The US scrambles to meet surging power demand by 2030

28 january 2026 16:00 CET | ***RaboResearch*** | Research

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For years, electricity demand barely moved – growing less than half a percent annually, kept in check by energy efficiency gains even as the economy expanded. But that long plateau is now breaking and the US power grid wasn't built for this decade's challenges. Can the gap of up to 170 GW between current generation capacity and 2030 peak demand be closed in time?

Summary

- Electricity demand in the US is surging after 20 years of flat growth. By 2030, electricity consumption could jump 20%, with peak load rising from 760GW to 850-930GW in 2030. Data centers, electrification, and onshoring of manufacturing are driving this combined surge, adding continuous, location-specific load that strains local infrastructure.

- Solar and storage dominate capacity additions through 2027, while gas lags behind. Solar leads the expansion, adding over 40GW of capacity annually through 2027. Storage follows with a 15GW of annual capacity growth through 2030. New gas plants ramp to an average 21GW of annual capacity additions, starting in 2027 through 2030 as turbine backlogs start to clear.

- Gas plant costs have tripled since 2022. A 1GW combined-cycle plant cost USD 722 million in 2022, USD 2.4 billion today, and could reach USD 2.8 billion by 2028 due to turbine backlogs and tariffs on steel, aluminum, and copper.

- Policy timelines are compressing. Projects starting by July 4, 2026, are safe-harbored for full Investment Tax Credit (ITC)/Production Tax Credit (PTC). Those starting after that date must complete by December 31, 2027 to qualify. Foreign Entity of Concern rules add a decade of annual compliance reviews on top of these compressed timelines.

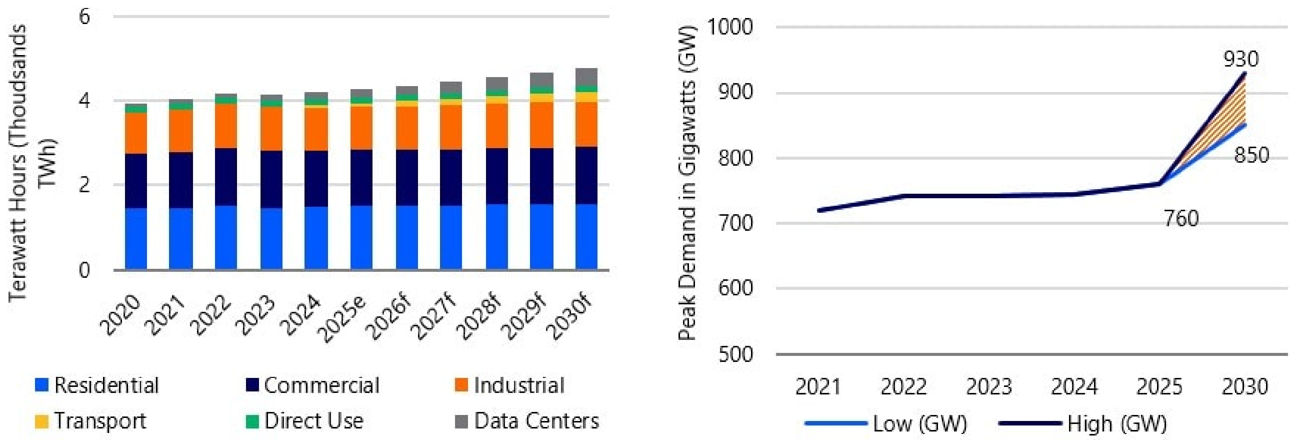
- LNG export growth could push power prices higher. US LNG capacity will increase by 67% by 2028. If gas scarcity develops and new gas plants remain expensive, wholesale power prices and Power Purchase Agreement prices could rise, potentially making renewables competitive without credits.

Twenty years of flatline growth has ended

For years, electricity demand barely moved – growing less than half a percent annually, kept in check by energy efficiency gains even as the economy expanded. But that long plateau is now breaking and the US power grid wasn't built for this decade's challenges.

After two flat decades, demand is rising again, and fast. By 2030, total electricity consumption could climb by as much as 20% from today's ~4,300TWh, and the system peak – meaning the highest moment of total grid demand – could jump from around 760GW today to between 850GW and 930GW (see figure 1). Importantly, the peak is rising faster than the average. That's because much of the new demand driven by data centers, electrified transport, and industrial reshoring, is continuous and location-specific, adding stress to certain regions even if the national average looks manageable.

Figure 1: Forecast US electricity consumption, 2020 to 2030



Source: US Energy Information Administration (EIA), ICF, American Clean Power Association, Grid Strategies, RaboResearch 2026

Data centers are among the most consequential drivers of this new load. Unlike homes or offices that follow daily usage cycles, data centers run 24/7, pulling large volumes of power continuously, with limited flexibility to ramp down. Once operational, they remain fixed loads on the grid for decades. Their location decisions hinge on where they can access uninterruptible power, transmission capacity, and fast interconnection approvals. As a result, electricity demand is clustering around key substations and transmission corridors in regions like northern Virginia, central Ohio, and west Texas, where load is rising faster than infrastructure can keep pace.

Beyond data centers, the electrification of vehicles, heat pumps, and water heaters doesn't just add capacity. It reshapes how and when electricity is used. As more homes and fleets move from gasoline and natural gas to electricity, the grid takes on the full weight of those sectors. Smartly designed programs such as time-of-use pricing and managed charging can help shift demand away from peak hours. But they do not eliminate the need to generate and deliver additional electricity.

This evolving demand profile is further reinforced by the return of heavy industry. The expected reshoring of battery plants, semiconductor chip manufacturing facilities, and advanced materials hubs could add a new layer of inflexible, round-the-clock electricity use. These sites require continuous supply of reliable power, as their load is constant and not seasonal. Like data centers, they tend to cluster in regions with available land, workforce, and transmission access, intensifying the strain on interconnection points already juggling queue backlogs and limited grid capacity.

Electricity demand is no longer a background concern. It has become the defining force in grid planning, shaping priorities and timelines, and determining where resources must go. With demand rising faster than expected, the next test is whether supply can keep up.

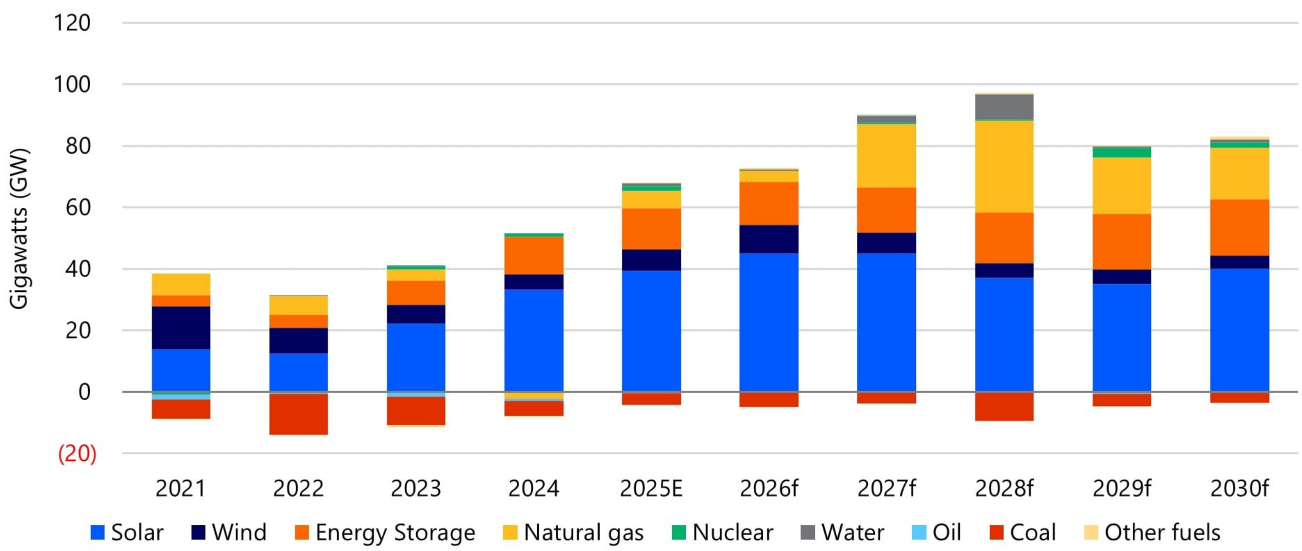
Renewables lead because they can be built fastest

Demand is setting the pace. The question is which technologies can deliver new megawatts fast enough to cover the expected 170GW gap between current capacity and 2030 demand.

In 2025, natural gas and coal contributed approximately 59% of total US generation, with gas at 43% and coal at 16%. Nuclear made up 19%, while renewables including wind, solar, hydro, and other sources accounted for 21%.[1]

The capacity being added looks very different from what's currently in place. The project pipeline through 2028 is dominated by solar and storage capacity. Solar additions are expected to average around 40GW annually from 2026 through 2030 (see figure 2). Battery storage is scaling alongside it, with about 15GW expected annually through the end of the decade. New natural gas plants enter later in the cycle, averaging 21GW per year starting in 2027, as turbine manufacturing backlogs start to clear. Coal retirements continue steadily across the decade. Two factors drive this sequencing: economics and delivery timelines.

Figure 2: Forecast net generation capacity additions, 2021 to 2030



Source: S&P Capital IQ, Bloomberg New Energy Finance (BNEF), Reuters, RaboResearch 2026

Renewables and storage lead on cost

On economics, Lazard's 2025 LCOE+ report shows utility-scale solar at USD 38 to USD 78 per megawatt-hour (MWh) and onshore wind at USD 37 to USD 86 per MWh. While wind economics remain competitive, development has slowed due to policy uncertainty and permitting constraints, with offshore projects paused and onshore development increasingly concentrated on private land in supportive states. Existing gas units that are already installed dispatch cheaply, at around USD 24 to USD 39 per MWh, depending on regional fuel prices. New combined-cycle gas turbines (CCGTs) sit higher, between USD 48 and USD 107 per MWh, depending on fuel and capital assumptions. The capital expenditure for CCGTs has increased sharply. In 2022, a 1GW gas plant cost around USD 722 million to build. As per a recent S&P Global Market Intelligence report, that same project would cost approximately USD 2.4 billion today, as tariffs on steel, aluminum, and copper add pressure and demand exceeds supply.

Battery storage costs vary widely depending on use case. Lazard places the levelized cost of a 100 MW or four-hour battery at USD 115 to USD 254 per MWh. Nuclear, while receiving renewed policy interest, remains the most expensive option at USD 141 to USD 220 per MWh, shaped by long permitting cycles, high financing needs, and construction risk.

Speed determines the buildout

Renewables and storage can be developed in 12 to 36 months if interconnection is available. That makes them the only technologies fast enough to respond to near-term load growth. Natural gas plants take significantly longer to reach commercial operation, with order books and EPC schedules now stretching into 2028. GE Vernova, one of the world's largest gas turbine manufacturers, reported that delivery timelines for turbines have extended as much as seven years, with limited new production slots available until the end of the decade.

This creates a visible sequencing driven by both economics and timelines. Solar and storage arrive first because they offer competitive costs, can be financed and built in 12 to 36 months, and qualify under compressed timelines of the One Big Beautiful Bill Act (OBBBA). Well capitalized developers and sponsors are fast-tracking projects that can start construction by mid-2026 and reach commercial operation before the qualification windows close. Natural gas generation, despite relatively competitive LCOE for new builds, arrives late in the decade as turbine backlogs ease and capital costs remain elevated. Nuclear remains a next-decade story, with high-costs and project starts gated by permitting timelines and construction risk. In the interim, the gap between rising demand and dispatchable capacity looms larger, raising the stakes for policy, price stability, and investment decisions heading into 2026.

The rush to beat the credit cliff

The buildout is now bounded by policy windows that are closing fast. The timeline to qualify for ITC/PTC is narrowing, sourcing rules are tightening, and tariffs are lifting capital costs. The window to qualify for tax credits is measured in months, not years.

The tax credit race

The One Big Beautiful Bill Act resets the tax credit clock. Projects that start construction by July 4, 2026, retain the familiar Inflation Reduction Act (IRA) path, showing continuous progress and reaching commercial operation within four calendar years. However, projects that start after July 2026 must be placed in service by December 31, 2027, to qualify at all. The broad IRA runway has become a narrow takeoff window.

Compliance burdens extend well beyond that start date. Foreign Entity of Concern requirements, significantly expanded under the OBBBA, now screen tax credits annually for ten years, with recapture provisions if projects fail in any compliance year. Starting in 2026, renewables and clean energy manufacturing facilities (such as battery cell and solar panel production plants) must progressively reduce content from prohibited foreign entities (PFE) in their supply chains. What was once a one-time procurement check is now a decade-long documentation and audit process.

The impact from tariffs on project viability

Import tariffs are compounding those compliance costs. Section 301 on anti-dumping and countervailing duties, and Section 232 tariffs on steel, aluminum, and copper were originally implemented in 2018. They were reinstated with significant expansions in 2025, raising input prices across technologies. Storage has been hit hardest, with tariffs on Chinese batteries and components driving project costs up by more than 60 percent. Steel, aluminum, and copper tariffs touch every asset class, from solar racking to substation transformers to gas turbine casings. Capital budgets built on pre-

2024 assumptions no longer hold.

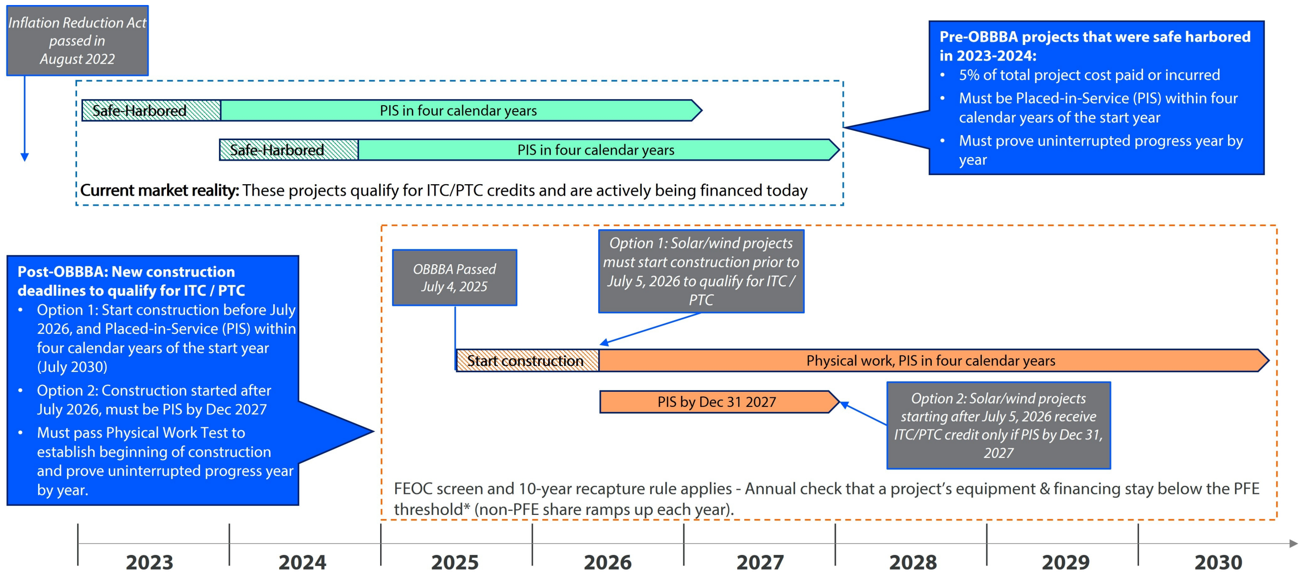
Siting restrictions

Beyond statutory changes, executive actions are reshaping where projects can be sited. Offshore wind pipelines have been paused through federal permitting reviews. Onshore wind and solar on federal land face extended environmental review cycles. Nuclear remains a stated priority, but licensing and construction timelines stretch well beyond this decade.

Which projects still qualify?

Pre-OBBBA projects still qualify. Assets that safe-harbored spending in 2023 or 2024, meeting the five percent expenditure test with documented costs, retain their IRA pathway (see figure 3). These are the projects most actively financed today, as their policy exposure is settled.

Figure 3: Tax credit timelines - pre-OBBBA versus post-OBBBA



Note: FEOC = Foreign entities may be prohibited, specified, or foreign-influenced, with limits on eligibility for projects using too many inputs from Prohibited Foreign Entities or giving "effective control; PFE=ProhibitedForeign Entity (China controlled or on National Defense Authorization Act restricted entity list, or any similar national security list) Source: US Department of Commerce, Federal Register, US White House, RaboResearch 2026

Post-OBBBA projects face two viable tracks. Start by July 4, 2026, and preserve the four-year window, or start after July 2026 and energize by December 31, 2027. Either way, annual FEOC compliance becomes a standing condition.[2] The market effects are visible in the pipeline. The solar and storage surge through 2027 reflects developers racing to meet the July deadline. Storage is the relative policy winner, with standalone ITC eligibility and short build cycles sustaining low-teens GW annual deployment even as solar and wind moderate post-2027.

Under OBBBA, credit monetization is about more than start dates. It requires traceable supply chains, annual attestations, and managing recapture risk over ten years. Safe harbor vintage, FEOC exposure by component, tariff-adjusted EPC costs, and interconnection queue position now sit alongside merchant exposure in credit committee memos. Policy no longer just supports the build. It determines who can build, with what components, and by when.

LNG growth could price gas out, and renewables in

Policy sets the rules. LNG sets the floor under the fuel. US LNG export capacity is on track to increase by approximately 67% by 2028, rising from ~15 billion cubic feet a day (bcf/d) to ~25 bcf/d. As Gulf Coast liquefaction trains reach commercial operation at Golden Pass, Port Arthur, Plaquemines, Rio Grande, and Corpus Christi Stage III, feed gas demand for liquefaction will climb sharply. That gas must come from the same basins and pipelines that supply power plants across ERCOT, SPP South, and the Southeast.

The math is straightforward. More LNG capacity means more feed gas pulled toward export terminals, tightening the availability of supply for domestic power generation. If scarcity develops, whether from production shortfalls, pipeline bottlenecks, or storage draws that can't keep pace, we could see natural gas prices rise, and that's only part of the cost pressure facing the power sector.

Layer in the elevated capital costs of natural gas plant at USD 2,400/kW today and potentially USD 2,800/kW by 2028, and the economics tighten further. New gas capacity arriving late in the decade will need higher power prices to justify the investment. Existing gas plants will capture the margin, but new builds require returns that reflect both expensive turbines and more volatile fuel costs. The result could be upward pressure on wholesale prices and the power purchase agreements (PPA) levels that developers use to finance new projects.

If wholesale power prices drift higher and PPA rates follow, the question becomes - do renewables still need subsidies to clear the market? They absolutely help, and they accelerate deployment. But with natural gas-driven higher power prices, renewables become increasingly viable on cost alone in many markets.

Can supply meet demand?

Can the gap of up to 170GW between current generation capacity and 2030 peak demand be closed in time? The buildout math suggests yes, but the reliability math is less certain. Solar and storage are moving fast enough to cover the capacity shortfall, but much of that capacity expected to come online is intermittent. If demand growth materializes as projected, the real test becomes dispatchable capacity. Gas plants won't scale until 2027-2028 and will arrive expensive, which could create a multi-year window where the grid manages rising peak demand with fewer firm resources than traditional planning assumed. How that potential gap gets bridged, whether through storage performance improvements, demand flexibility, novel generation technologies, or alternative development pathways that bypass traditional interconnection queues, will shape the next phase of grid evolution.

Footnotes

[1] U.S. Energy Information Administration – Electricity in the U.S.

[2] FEOC (Foreign Entity of Concern) compliance requires annual certification that projects do not exceed material assistance thresholds from prohibited foreign entities and that supply chain content from such entities remains below specified limits. Projects must maintain compliance for ten years or face tax credit recapture.

Disclaimer

Source

https://knowledge.rabobank.com/en/knowledge/d011512857-the-us-scrambles-to-meet-surging-power-demand-by-2030