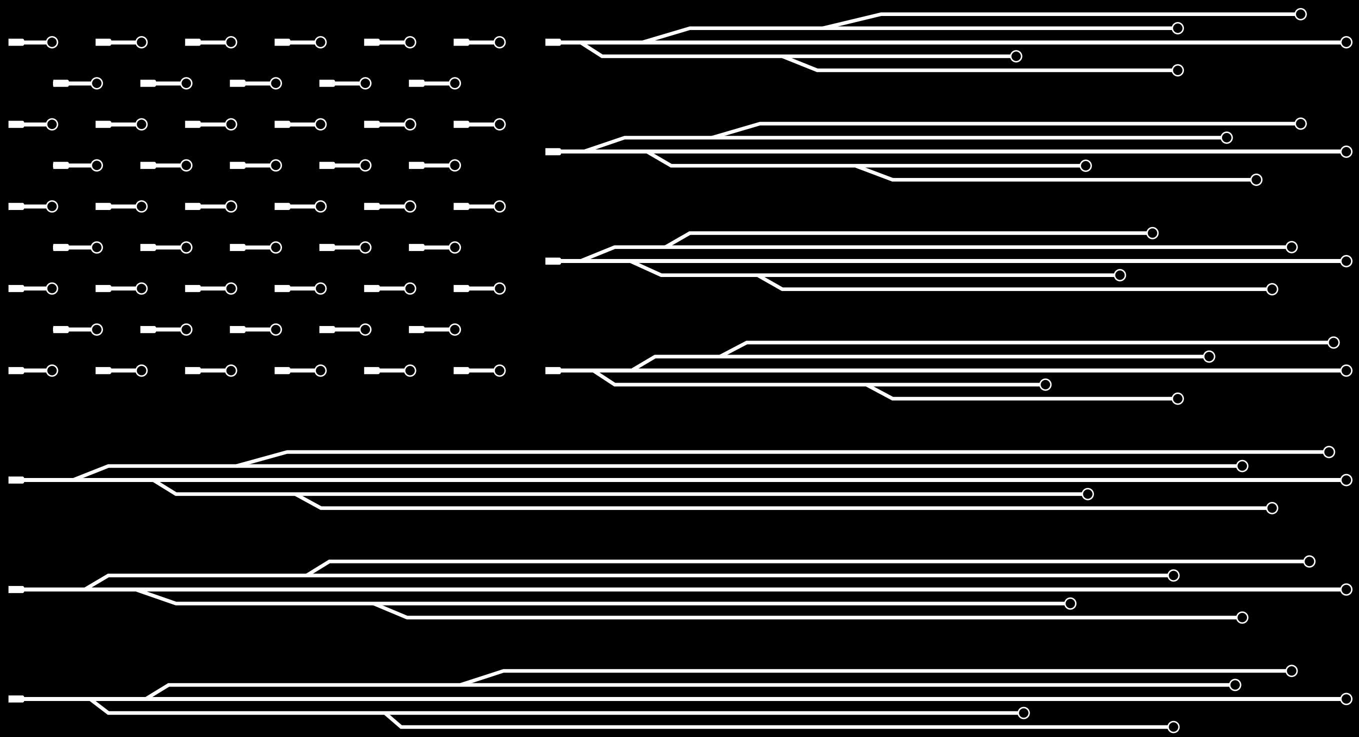

GROWING THE U.S. ELECTRICITY SYSTEM

OPPORTUNITIES AND CHALLENGES

UH Energy
UNIVERSITY OF HOUSTON

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About

About the Author

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Executive Summary

Electricity demand in the U.S. is expected to grow significantly in the coming years due to rapid expansion of data centers, as well as the ongoing electrification of the industrial and transportation sectors. How much demand will grow depends on several factors: Current projections call for demand to rise 32% by 2030, and it could be even higher, as the continued improvement in chip technology so far has increased computing intensity rather than reducing energy consumption. Or it could be lower if the more limited availability of capital means a handful of massive technology companies are the only entities that can afford to make these investments.

Adding to the complexity, utilities are increasingly requiring these hyperscalers — huge cloud computing and data center companies that can provide the infrastructure needed to support artificial intelligence and big data operations — to bring their own power sources or strong bilateral power supply contracts before allowing them to interconnect to the grid, which could slow demand growth.

Natural gas, solar, and batteries are expected to meet the increased demand in the short and medium term. Advanced geothermal and nuclear have potential in the longer term as those technologies mature. Interconnection bottlenecks and permitting challenges remain obstacles to deploying new generation resources in some areas. Given concerns about speed to power timelines, many data center projects are turning to behind-the-meter (BTM) generation systems, producing power on site and largely bypassing the utility grid.

Even with all these uncertainties, a few things are clear. The U.S. electricity system is aging and complex, and significant investment will be required to expand and increase the resilience of the grid. Simply building new sources of power generation won't be enough. Expansion of intra- and inter-regional transmission capacity will be critical to ensure new power supplies can reach the areas of increased demand. That in itself is complicated: the biggest challenge to constructing new transmission lines is the multi-layered permitting processes required at the local, state, and even federal levels. Increasing existing transmission capacity, known as reconducting, is often a faster and cheaper method of grid expansion.

Distributed energy resources (DERs) or virtual power plants (VPPs) can include on-site generation, energy storage, industrial demand flexibility, bi-directional electric vehicle charging, and smart thermostats and water heaters. These offer significant potential to improve grid flexibility and resilience as well as reduce costs. However, they face regulatory and market challenges in many areas.

But there are also opportunities, even a few relatively simple concepts that can be deployed. Because the power system — generation, transmission, and distribution — is built to serve infrequent spikes in demand, including when air conditioning (cooling) use spikes during the hottest summer days, less than half of system capacity is used throughout the year. This provides an opportunity to improve grid management to increase system utilization and reduce the investment required to accommodate growing demand. If new electricity demand can be added to the existing power system where and when there is spare capacity, the system's fixed costs will be shared by more customers, putting downward pressure on rates. Higher system utilization while demand is growing can be accomplished in three ways. New load can be added at locations with existing headroom, new load can be added at times with spare capacity, or incentives can be provided to reduce existing demand at system peaks.

Two major potential technology improvements could dramatically shape the future of the U.S. grid: the development of cost-effective long-duration energy storage (LDES) and the development of advanced grid technologies. Inter-day LDES is defined as shifting power by 10–36 hours and includes almost all mechanical storage technologies and some electrochemical technologies (e.g., flow batteries). Multi-day/week LDES is defined as shifting power by 36–160+ hours and includes many thermal and electrochemical technologies. Multiple advanced grid technologies are likely to be available to address near-term hotspots and modernize the transmission and distribution grid. These technologies focus on transmission line capacity, situational awareness and system automation solutions, grid-enhancing technologies that improve system utilization and performance, and the associated foundational systems necessary to enable advanced technologies and a modern grid.

Significant investment will be required to expand and increase the resilience of the aging and complex U.S. electricity grid. Along with building new sources of power generation, expansion of intra- and inter-regional transmission capacity will be critical to ensure new power supplies can reach areas of increased demand.

Two emerging issues inject additional uncertainty into demand, especially related to data centers. The first is water consumption. Data center developers are increasingly tapping into freshwater resources for cooling, putting the water supply for nearby communities at risk. Today data center developers most commonly withdraw water from freshwater sources and employ water-intensive practices, such as air cooling through water evaporation. However, other options can reduce reliance on community water supplies, including projects planning to use oilfield wastewater rather than freshwater. The second issue is growing community opposition to data centers locating nearby, driven by increased water use and wastewater treatment requirements, noise pollution, competition for land, and visual aesthetics. At least 7 in 10 Americans now say they would oppose a data center being built near their home. Some geographic jurisdictions are considering significant restrictions or even bans on data center development.

Background

The U.S. electricity system is a large and complex part of the overall energy system and is poised to undergo significant growth and change over the next two decades. Demand is expected to grow significantly, accompanied by continued pressure to reduce the carbon intensity (CI) of energy generation. Major investments need to be made even with the ongoing uncertainty as government policy is evolving and new players and business models are emerging.

Symposium Focus

The Gutierrez Energy Management Institute (GEMI) in the C. T. Bauer College of Business at the University of Houston held a symposium and workshop in April 2026, “The Role of Electricity in the Changing U.S. Energy Landscape — Enablers, Constraints, and Future Pathways.” The focus was on likely demand and generation growth, transmission infrastructure and grid management challenges, and the role of new technologies and included a keynote presentation, followed by panel discussions and small-group discussions of key questions.

Participants included high-level energy executives, academics, and other energy thought leaders, with sessions conducted under the Chatham House Rule, used around the world to encourage inclusive and open dialogue in meetings. Its guiding spirit is to share the information you receive without revealing the identity of the source of the information or that of other participants.

This white paper is based on information from the symposium, along with additional research.

The Ultimate Level of Demand Growth

Electricity demand in the U. S. has been relatively stable for years, as the increase in electricity-consuming activities, mainly in the residential sector, was offset by increased energy efficiency improvements. That's about to change.

While U.S. annual electricity demand rose only 10% over the past 20 years, or less than 0.5% annually,[1] it is now forecast, in a recent study by the University of Houston, to grow by an average of 5.2% per year over the next five years. Peak demand growth is forecast at 166 gigawatts (GW), a 3.7% annual rate (Figure 1). Over the past three years, the five-year forecast of utility peak load growth has increased by more than a factor of six, from 24 GW to 166 GW. Electricity use is forecast to increase even more quickly than peak power demand. By 2030, forecasts indicate total electricity use will increase by 32%.

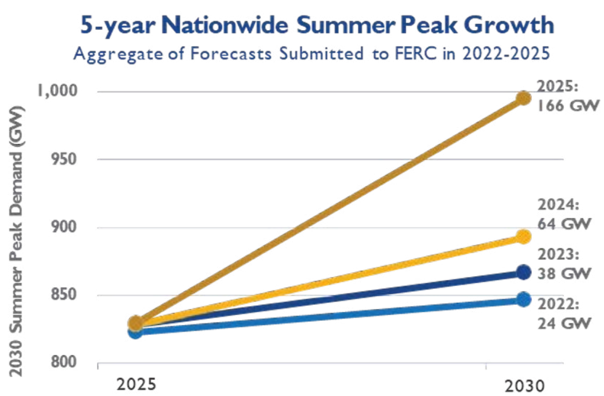


Figure 1. Potential Demand Growth.
Source: Grid Strategies National Load Growth Report (November 2025)

Of that 166 GW of forecast peak load growth over the next five years, roughly 55%, or 90 GW, is linked to data centers. In addition to being the largest collective source of increased demand, data centers also make up the largest individual loads on the grid today. The top 10 are all data centers, with loads ranging from 500 megawatts (MW) to 1,400 MW. This compares to the 10 largest non-data center loads, which range from 200 MW to 500 MW and include industrial users such as aluminum smelters, steel plants, energy and chemical plants, and new semiconductor plants. Many of these industrial plants cover part of their demand through on-site generation and are managed as an interruptible load, able to reduce their demand at times of high stress on the grid. The level of data center demand growth could be higher than forecast due to continued improvement in chip technology, which so far has focused on boosting computing intensity rather than reducing energy consumption.
Actual demand growth could also be lower than expected due to more limited availability of capital, leaving these investments to be funded by the balance sheets of only five or six hyperscalers. How this capital will flow through those balance sheets is not necessarily transparent.

Industrial and manufacturing drives about 30 GW of anticipated demand growth over the next five years, with the oil and gas and mining sectors contributing perhaps 10 GW more. Other drivers, representing about 30 GW of growth, include general residential and commercial growth (building electrification), EV charging (transportation electrification), and other factors (Figure 2). Industrial electrification is taking place in sectors such as steel and cement.

In buildings, the stock of installed heat pumps, operating on electricity, has nearly doubled over the last 10 years, from 13 million to 23 million, and heat pumps have consistently outsold gas furnaces since 2021. In addition, over the past 10 years, electric heat pumps have increased in the monthly market share of residential cooling equipment, to 47% from 33%.[2]

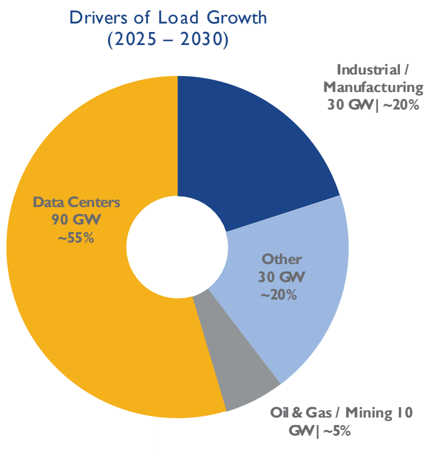


Figure 2. Drivers of Load Growth.
Source: Grid Strategies National Load Growth Report (Nov 2025)

U.S. annual electricity demand is forecast to grow by an average of 5.2% per year over the next five years, with peak demand growth expected at 166 gigawatts (GW). Of that, around 55%, or 90 GW, is linked to data centers.

A shift in heavy-duty trucking also has the potential to significantly increase demand. Tesla's recent introduction of a new model with a 500-mile range is estimated to have a comparable levelized cost of trucking ($/ton-mile) at $0.12/kWh compared to $3.00/gal for a diesel truck, even with a purchase price double that of a diesel truck.[3] Finally, while EV demand in the U.S. has stalled with the repeal of the $7,500 federal tax credit originally included in the Inflation Reduction Act, higher gasoline prices and potential EV price declines could lead to a resumption in light-duty EV sales growth and electricity demand.

Growing electricity demand will not be felt equally across the country. The Dominion service territory within PJM, Southern Company service territory within SERC, and the Electric Reliability Council of Texas (ERCOT) West zone in West Texas are among the areas expected to have the highest growth. Those service territories are forecast to see total annual electricity demand growth exceeding 7% and peak demand growth exceeding 5% through 2035.[4]

In ERCOT, as of April 2026, the interconnection queue included over 1,800 projects with a total capacity of 465 GW, or about five times the current peak demand. Not all of those projects will ultimately be built and come online; ERCOT's associated probability-weighted estimate is for an additional 113 GW of demand, more than 130% of current peak demand. At present, only about 11 GW of additional capacity is actually under construction, although ERCOT estimates about 60 GW of additional capacity is likely to be completed in the next five years,[5] which is higher than other forecasts. Implementation of Senate Bill 6, passed by the Texas legislature in 2025 to regulate data centers and large energy loads connecting to the ERCOT grid, should provide more clarity and will likely lower that estimate.

In terms of limits to growth for large data centers, securing long-term contracts and interconnection permissions are at the top of the list today but NIMBY — Not In My BackYard — sentiment against the projects appears to be growing.

Generation Sources Most Likely to Meet This Demand

Regardless of exactly how demand grows, new utility-scale generation capacity will be needed. Most analysis indicates an "all of the above" generation mix across technologies and fuel types will be required to meet rising demand, based on a cost optimal approach that delivers reliability.[6]

Natural gas, onshore wind, solar, and energy storage are expected to be the primary growth sources over the next 10 years, with advanced geothermal and small modular nuclear potentially growing in the longer term. On a market share basis, onshore wind, solar, and battery energy storage will grow to about a third of the market share by 2035 (Figure 3). This mix is driven by the relative cost advantages of these generation technologies.

While estimated levelized costs of electricity (LCOEs) vary, most estimates show the cost of these sources are now comparable in Texas (Figure 4). Note that onshore wind and hybrid solar, coupled with four-hour battery storage, are not 24/7 baseload generation, while natural gas combined-cycle gas turbine costs don't include the cost of carbon capture and storage (CCS) to decarbonize gas generation. Recent work on 24/7 solar generation schemes based on an overbuild of solar capacity with battery storage suggests that in good solar locations these facilities can meet 97% of annual demand at costs approaching $100/MWh, a 50% reduction in the last five years.[7] Meanwhile, costs for new gas turbines are increasing due to supply shortages. With estimated costs of adding carbon capture and storage of $40/MWh in locations with favorable geology,[8] costs of 24/7 solar and decarbonized gas generation appear to be roughly comparable.

Some of this new capacity will be installed "behind the meter" (BTM). BTM resources can usually be deployed faster because the full data center load does not depend on the grid. However, projects employing BTM resources are typically more expensive than those that are fully dependent on the grid. These costs for the developer include overbuilding redundant backup generation capacity and an entire microgrid system that would be unnecessary if the facility relied completely on grid power.

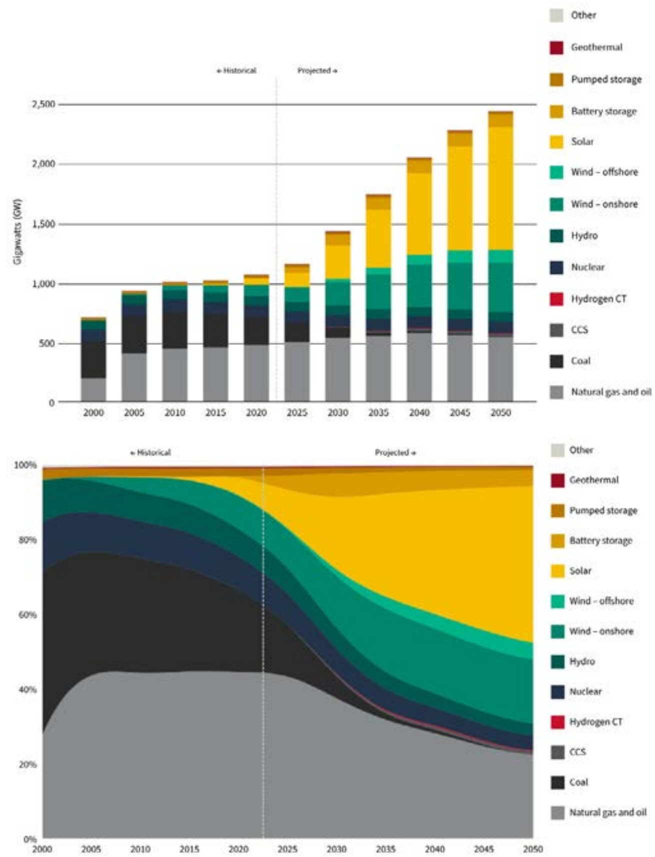


Figure 3. Installed Generation and Projections for Electricity Mix Change in GW.
Data Source: EIA

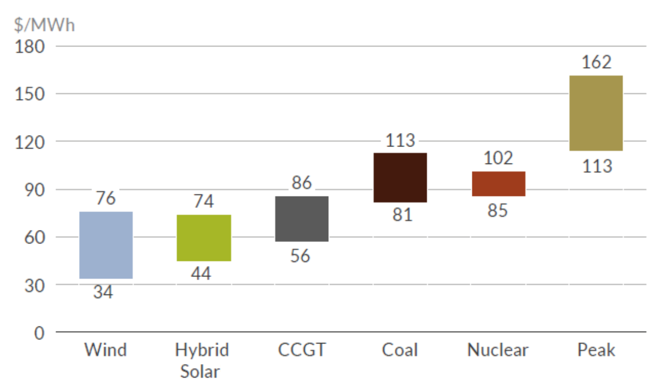


Figure 4. Levelized Cost of Electricity.
Source: Aurora, The Role of Electricity in the Changing US Energy Landscape (April 2026))

The public at large also loses when those investments are made outside the shared grid, as they do not necessarily finance generation, transmission, or distribution infrastructure that benefits other ratepayers. About 25% of announced data center projects include their own BTM power. Nearly every hyperscaler is pursuing BTM power projects, either directly (Meta, Microsoft, Google, Amazon, and Oracle) or through signed leases (OpenAI and Anthropic). Development in just five states (Texas, Utah, Pennsylvania, Ohio, and New Mexico) accounts for 83% of all proposed BTM capacity. Texas alone accounts for over 40%.

Top states for data center development tend to have proximity to major natural gas production as well as regulatory frameworks that favor rapid development. States in the Northeast, for example, may face higher gas costs and potential pipeline bottlenecks that can emerge in times of extreme weather. Lengthy permitting processes and strict rules about large loads connecting to the grid complicate the issue in many states.[9]

New legislation in Texas has tightened the regulatory framework for projects within the ERCOT grid. Outside of ERCOT, a data center developer has to have accredited capacity to fit into the margin framework across the various balancing authorities in the West, Midwest, and Northeast. Utilities in these areas are often only willing to work with hyperscalers if they bring their own generation or their own bilateral power supply contract. Many states with regulated utilities would require legislation to allow anyone other than the utilities to build generation capacity.

Given concerns about speed to power timelines, the equipment being deployed for most of these BTM plants is not what utilities typically buy to generate power. Heavy-duty combined-cycle gas turbines — the most efficient option for baseload gas-fired power — have long lead times and are largely unavailable in the short term. Lead times for gas turbines averaged around five years in 2025, and prices are expected to triple to $600/kW by 2027 from 2019 levels.[10] Data center developers are instead turning to:

- Mobile gas generators strapped to semitrucks
- Aeroderivative turbines originally designed for aircraft and warships
- Reciprocating engines that ramp fast but are less efficient
- Refurbished turbines acquired from industrial operations

Data centers are also increasingly installing on-site solar or new dedicated solar plants as renewables and storage continue to be the fastest way to get new electrons on the grid while they wait for additional gas-fired generation to be built. There are also concerns that the powerful combination of rising LNG exports and soaring demand for power from mushrooming data center build-out will drive up U.S. gas prices to nearly $5/million British thermal units (mmBtu) in constant dollars by 2035.[11] Many developers are deploying hybrid clean power systems featuring utility-scale solar and battery storage to meet rapid deployment timelines. Enbridge recently announced a 365 MW solar project with 200 MW battery storage in Wyoming as part of a 1.6 GW agreement to supply clean energy to Meta. Leading developer NextEra Energy has a 110 GW inventory of stand-alone and co-located battery storage projects.[12]

New technology is also being deployed to speed up the timelines of solar projects. Some are pre-designed in software and installed in large part by robots, allowing them to go up in months, rather than the several years that it typically takes solar projects to move from development to power.[13]

At least one company, Google, is changing its data center energy procurement business model from a typical commercial relationship between a data center customer and a power plant builder towards more vertical integration. In December 2025 it purchased Intersect, a builder of data centers and related energy infrastructure. Google has already initiated two data center projects in Texas leveraging these capabilities. The first, announced prior to the acquisition, involves a data center co-located with solar and storage. The second is a data center with wind, solar, battery storage as well as on-site gas generation.[14]

Transmission and Interconnection Bottlenecks

REGION	REGIONAL PLANNING	INTERREGIONAL PLANNING	ENGAGEMENT	OUTCOMES	OVERALL GRADE	2023 GRADE
California	A+	B-	A-	A	A-	B
Northwest	F	C	F	B+	D+	D
Southwest	D+	C	F	B-	C-	D-
Texas	C	F	B	C-	D-	D+
Plains	A	C	B	B-	B-	C+
Midwest	A	B-	B+	C	B	B
Southeast	F	F	F	F	F	F
Mid-Atlantic	B	D+	B	C-	C	D+
New York	B+	C+	A-	C-	B-	C+
New England	B	C	A-	A	B	D+

Figure 5. Regional Transmission Report Card.
Source: Grid Strategies, 2025 Transmission Planning and Development Report Card (February 2026)

The U.S. electricity system is made up of a massive web of transmission and distribution lines, power poles, and other facilities. That includes 600,000 miles of transmission lines, 240,000 miles of which are considered high-voltage lines, and more than 5.5 million miles of local distribution lines, with over 180 million power poles.

In addition, there are more than 79,000 substation transformer facilities and more than 60 million distribution transformer facilities. Substation transformer facilities convert high-voltage power to levels that can be sent throughout the distribution network, while distribution transformers are smaller devices attached to distribution poles that further convert voltage to safe and efficient levels for industrial, commercial, and residential users.

Like much of the system, these facilities are aging: 70% of power transformers are at least 25 years old, 60% of circuit breakers are at least 30 years old, and 70% of transmission lines are at least 25 years old. Significant investments are required to replace this aging equipment, in addition to what is needed to meet growing demand. Continued investments also are needed to increase resilience, as over 80% of all transmission and distribution outages are due to weather events.[15] The current state of transmission varies significantly by region (Figure 5). The California grid receives the highest score, while the Southeast grid receives the worst.[16]

Upgrading transmission systems will matter. Studies considering the future of the U.S. grid show the lowest-cost electricity system portfolios that meet future demand growth and reliability requirements include substantial expansion in transmission.

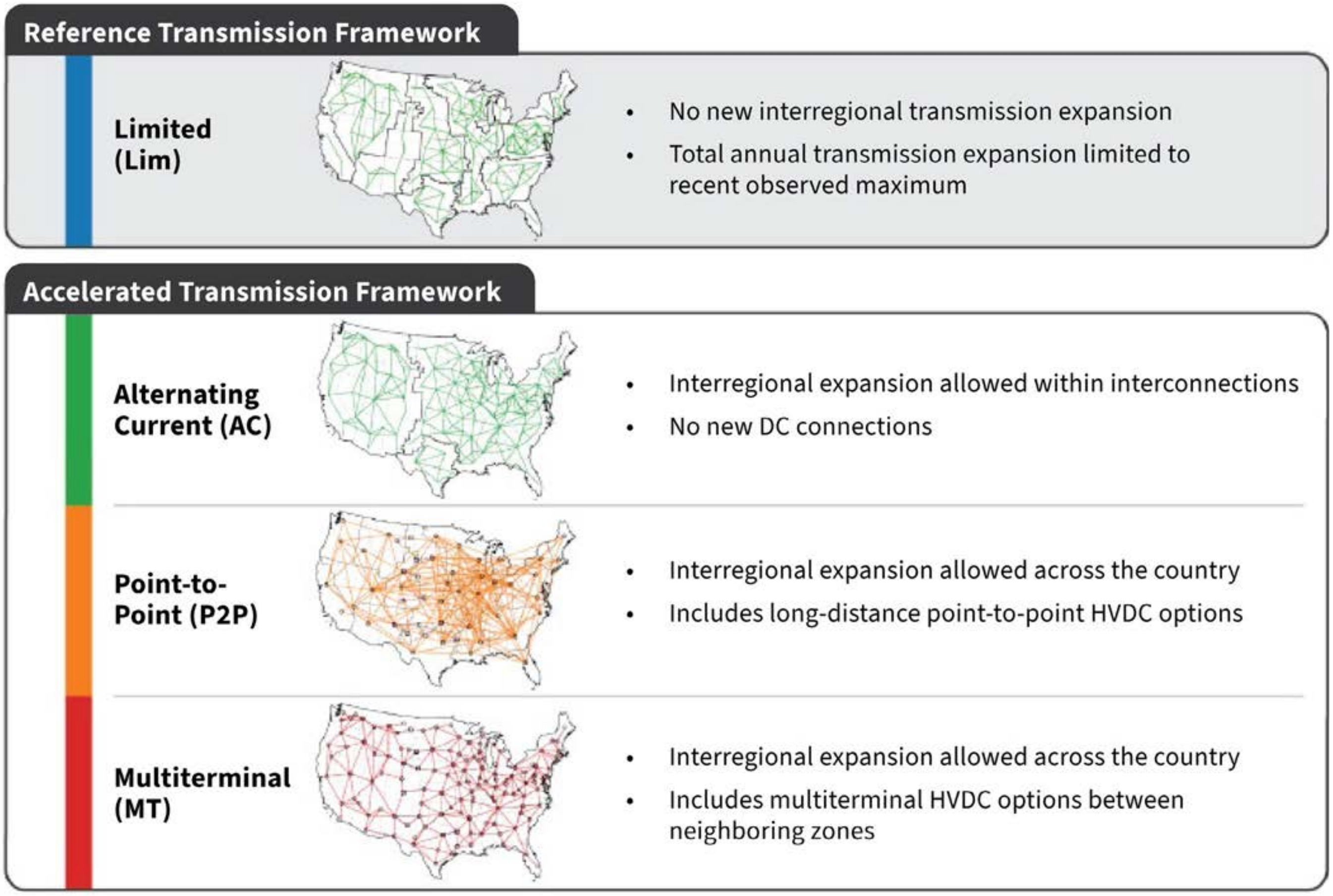


Figure 6. Transmission Expansion Scenarios.
Source: DOE, The National Transmission Planning Study (September 2024)

The U.S. DOE developed four different scenarios with increasing levels of transmission expansion over the next 30 years (Figure 6). The most limited investment scenario involves regional expansions tied to recently observed maximum rates and no new inter-regional capacity, which results in a grid expansion of 40% over 30 years (Limited Scenario). The most aggressive build-out scenario of regional and inter-regional transmission expands the system to 3.5 times its current size. The study finds that the absolute benefits increase in terms of generation, transmission, and storage costs commensurate with expansion (Figure 7). The benefit per dollar spent on transmission also climbs as investment increases. In the core scenarios, the benefit-to-cost ratio is 1.6 for the Alternating Current Scenario, 1.7 for the Point-to Point Scenario, and 1.8 for Multiterminal Scenario.[17]

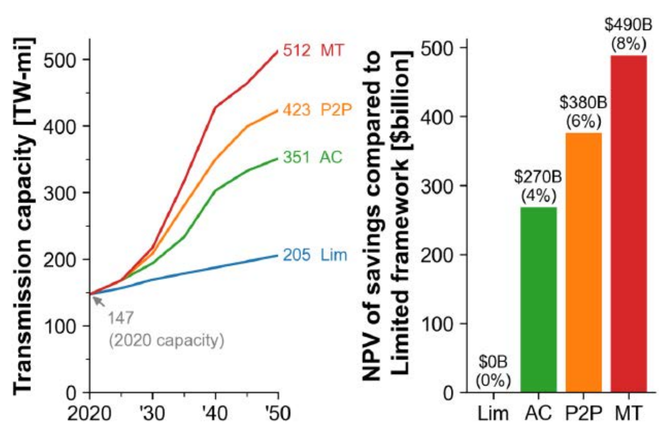


Figure 7. Transmission Expansions Scenarios' Impacts.
Source: DOE, The National Transmission Planning Study (September 2024)

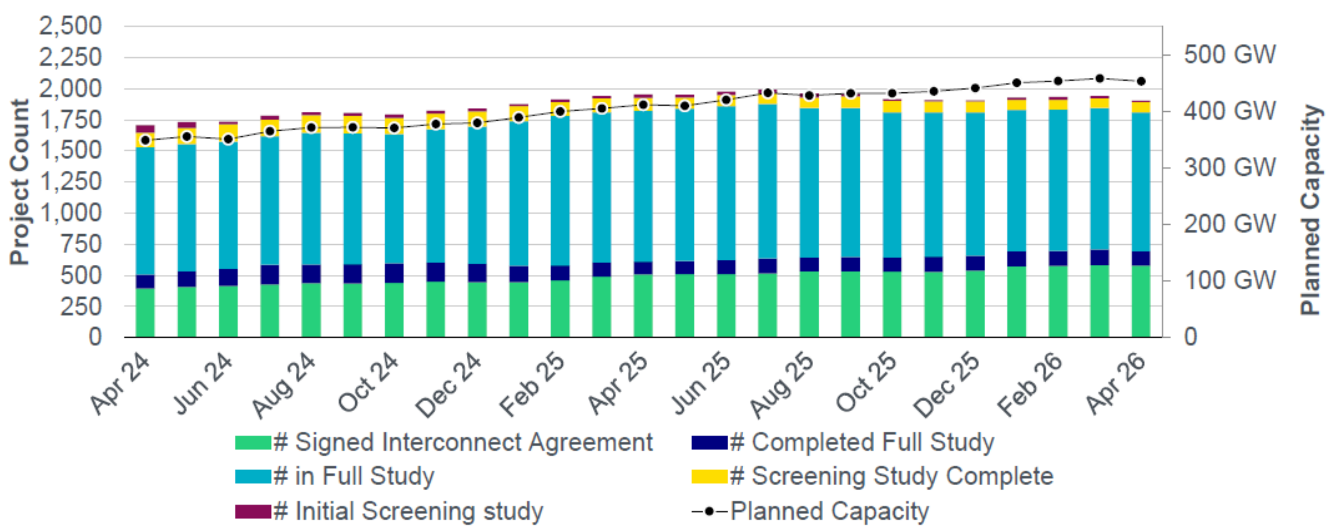
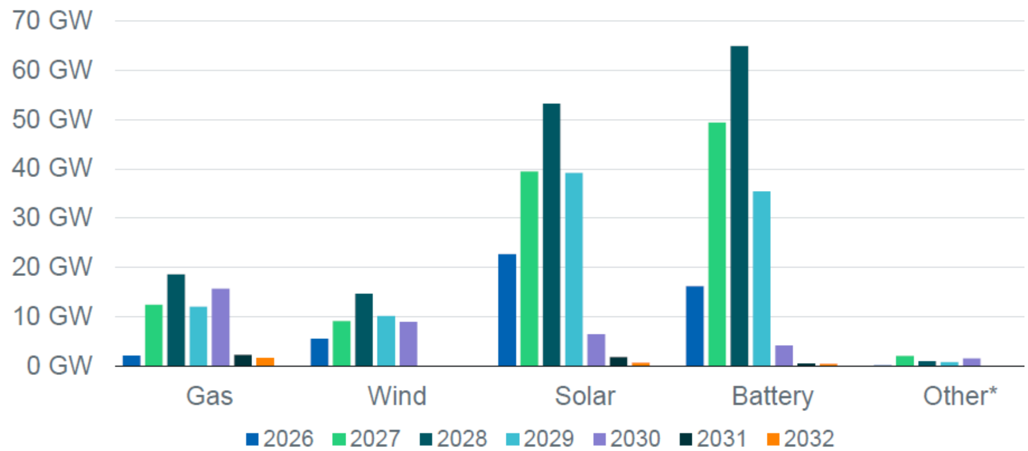


Figure 8a. ERCOT Interconnection Queue by Project Phase.
Note: Covers 1965 active generation interconnection projects
Source: ERCOT Monthly Operations Overview (April 2026)



	Share
Gas	14%
Wind	11%
Solar	36%
Battery	38%
Other	1%

Figure 8b. ERCOT Interconnection Queue by Energy Type.
Note: Covers 1965 Active Generation Interconnection Projects
Source: ERCOT Monthly Operations Overview (April 2026)

Advanced geothermal companies are also eying BTM systems due to transmission bottlenecks in the western U.S. Fervo Energy, which is developing the first large-scale advanced geothermal project in Utah, has mentioned BTM as a growing possibility for its new plants.[18]

Interconnection bottlenecks are another increasing source of concern for data center operators. In ERCOT, the current interconnection queue is over 400 GW, or nearly five times the system current peak demand (Figures 8a and 8b). The vast majority of that is for solar and batteries (Figure 9). Texas has adopted new legislation for projects to be added to the queue and a new “batch” method to process interconnection requests, but it remains to be seen how much better visibility will be for the actual load likely to be connected. A number of policy changes are being discussed in various regional transmission organizations to modify their interconnection procedures.

Role of Distributed Energy Resources

Given the rapid growth in power demand and the potential for transmission and distribution infrastructure constraints, distributed energy resources (DERs) or virtual power plants (VPPs) could offer substantial benefits. The theoretical potential of VPPs to maximize the use of existing energy infrastructure — thereby reducing the need to build additional poles, wires, and power plants — has long been recognized. But there are significant coordination challenges between equipment manufacturers, software platforms, and grid operators that have made them both impractical and impracticable.

The components of VPPs can vary but typically include on-site generation, energy storage, industrial demand flexibility, bi-directional EV charging, and smart thermostats and water heaters (Figure 10).

The value proposition for VPPs is broad and includes generation resource adequacy, resilience, transmission and distribution infrastructure relief, as well as affordability and flexibility (Figure 11).

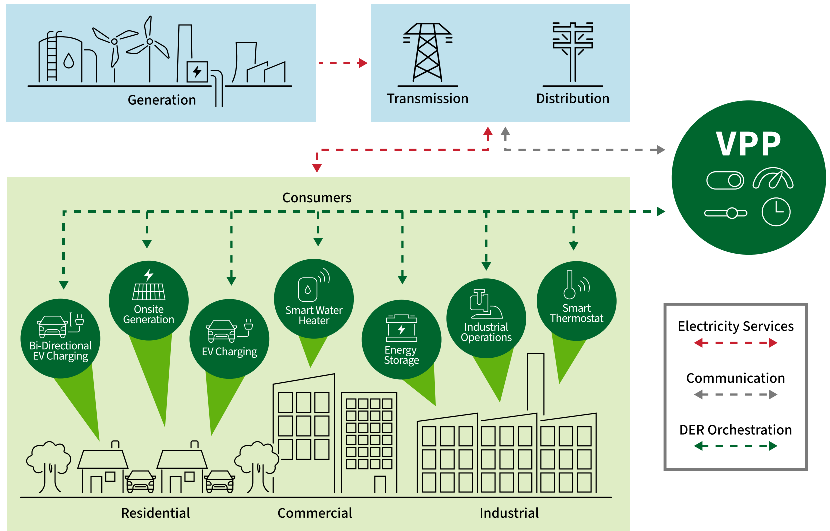


Figure 10. Potential Elements of Virtual Power Plants.
Source: DOE, Pathways to Commercial Liftoff – Virtual Power Plants (September 2023)

VPP value proposition

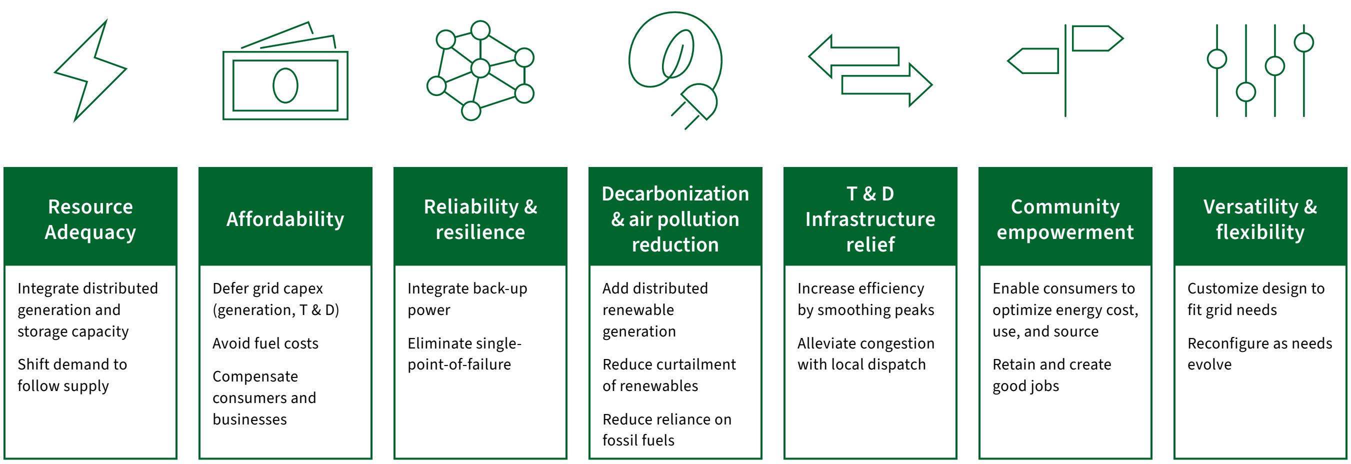


Figure 11. Potential Virtual Power Plant Value Proposition.
Source: DOE, Pathways to Commercial Liftoff – Virtual Power Plants (September 2023)

Electricity markets weren't designed for individual consumers to function as localized power producers. The VPP model also often conflicts with utility incentives that favor infrastructure investments. And some say it would be simpler and more equitable for utilities to build their own battery storage systems to serve the grid directly.

While VPPs today provide roughly 37.5 gigawatts of flexible capacity, the DOE forecasts that these could scale to between 80 gigawatts and160 gigawatts by 2030. That's equivalent to around 7% to 13% of current U.S. utility-scale electricity generating capacity (Figure 12).

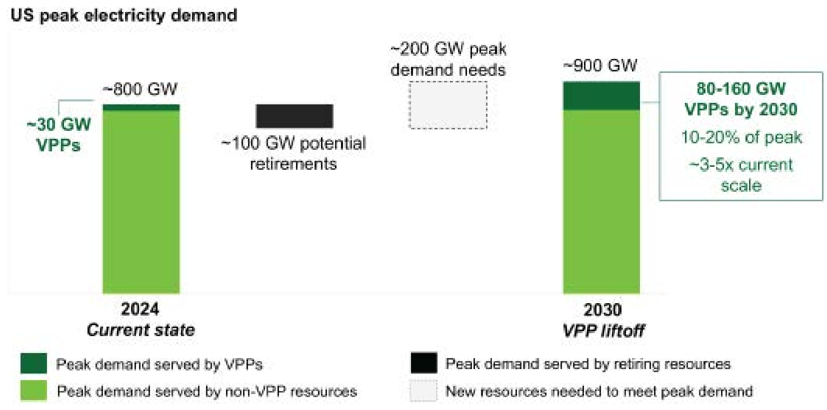


Figure 12. Potential Virtual Power Plant Impact.
Source: DOE, Pathways to Commercial Liftoff – Virtual Power Plants (September 2023)

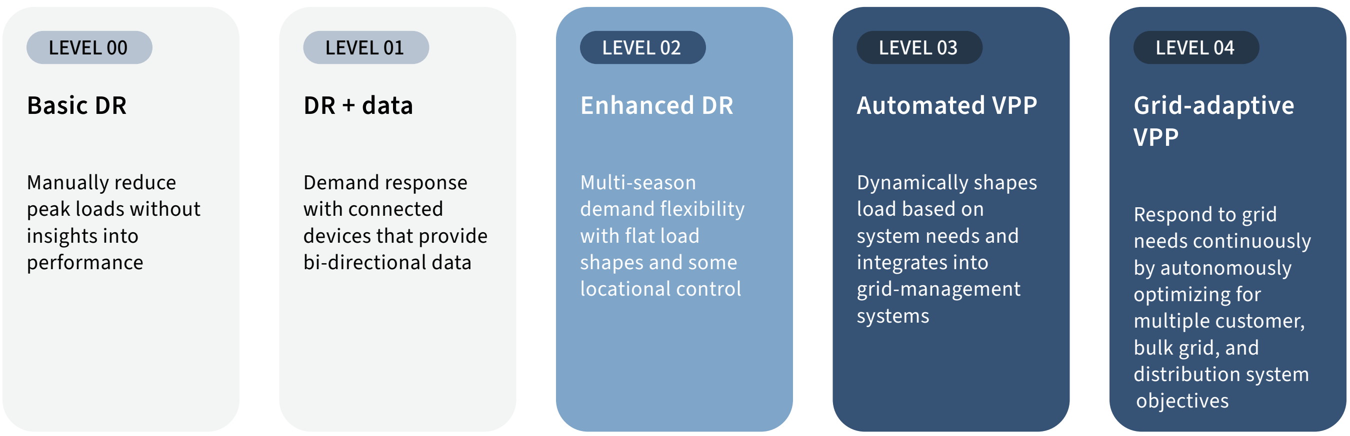


Figure 13. Virtual Power Plant Maturity Model.
Source: Energy Hub, Building Trustworthy Virtual Power Plants: The VPP Maturity Model (December 2025)

However, friction between the utility side and the regulatory side complicates efforts to align incentive programs with real needs. These points of friction include requirements to communicate real-time performance data — even for minor, easily modeled metrics such as a smart thermostat's output — as well as utilities' hesitance to share household-level metering data with third parties, even when it's necessary to enroll in a VPP program.

Grid operators risk overlooking the unique value VPPs can provide, particularly on the distribution grid, which delivers electricity directly to homes and businesses. Here, VPPs can help manage voltage regulation or work to avoid overloads on lines with many distributed resources, such as solar panels — things traditional power plants can't do because they're not connected to these local lines.

Understanding of the capabilities of VPPs has increased significantly and maturity models have been developed to characterize their potential capabilities (Figure 13).

The potential value delivered by VPPs has also become better understood (Figure 14).

One challenge is that most utilities still lack a natural incentive to support this resource. That's because investor-owned utilities — which serve approximately 70% of U.S. electricity customers — earn profits primarily by building infrastructure such as power plants and transmission lines, receiving a guaranteed rate of return on that capital investment. Successful VPPs, on the other hand, reduce a utility's need to build new assets.

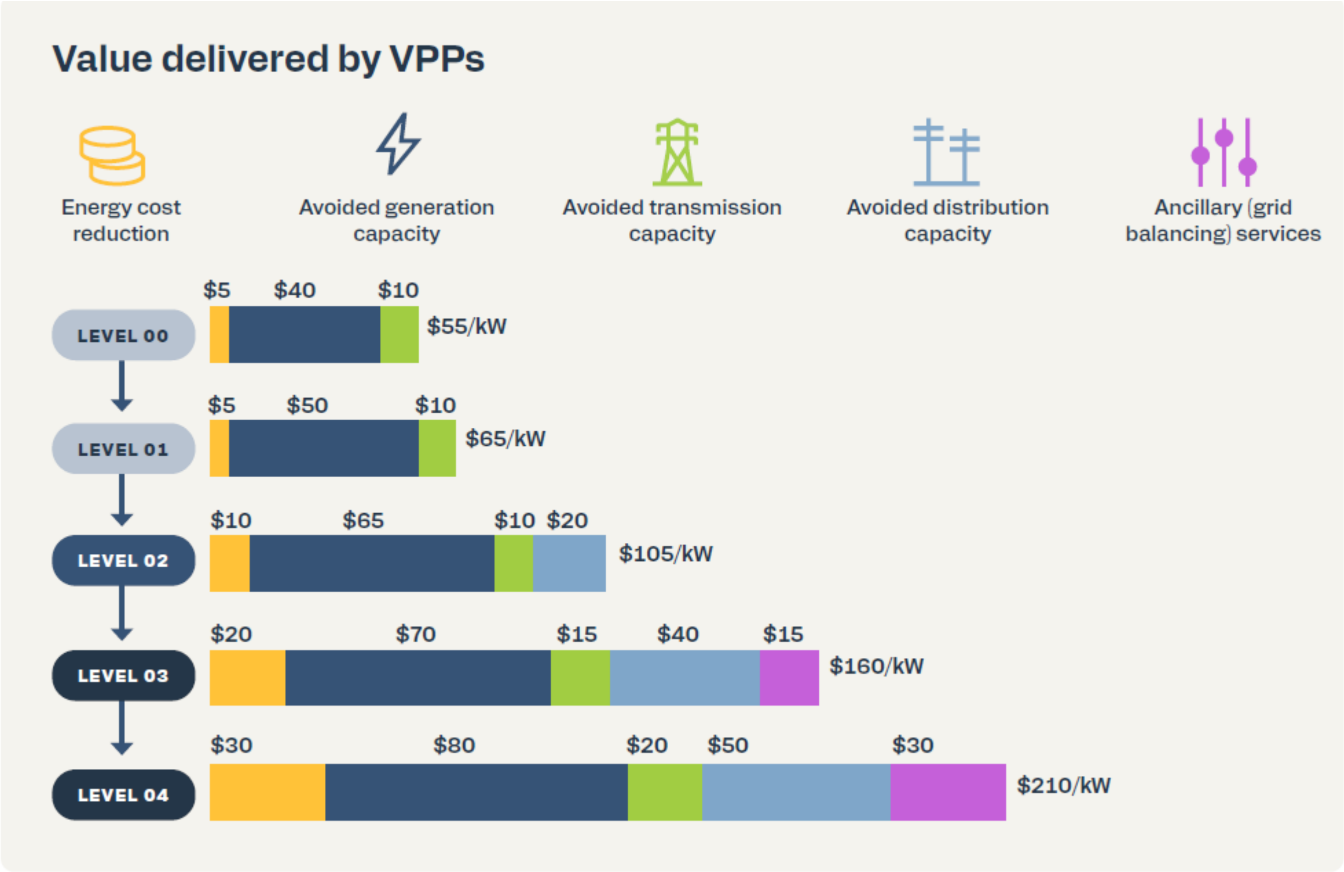


Figure 14. Potential Value Delivery by Virtual Power Plants.
Source: Energy Hub, Building Trustworthy Virtual Power Plants: The VPP Maturity Model (December 2025)

To increase adoption of VPPs, one option is to incentivize or require utilities to incorporate battery storage systems at either the transmission or distribution level into their long-term plans for meeting demand. Large-scale batteries would also help utilities maximize the value of their existing assets and capture many of the other benefits VPPs promise at a larger size, and therefore benefit from a lower unit cost. However, many VPP advocates also note that with grid interconnection queues stretching on for years, VPPs offer a way to deploy aggregated resources far more quickly than building out and connecting new, centralized assets.

Ultimately investor-owned utilities (IOUs) are unlikely to be able to build generation, transmission, and distribution facilities fast enough due to shortages of materials, equipment, and people. VPPs offer an option to accelerate expansion at lower cost.[19]

A challenge to be addressed for distributed energy resources, or DERs, is the need for Remedial Action Schemes, which are automated grid-protection mechanisms that detect abnormal conditions and rapidly execute pre-planned actions to maintain stability and prevent cascading blackouts without requiring immediate manual intervention. These systems monitor line flows, voltages, and system frequencies and once predetermined thresholds are crossed, trigger automatic corrective actions like generation tripping, load shedding, and system reconfiguration.

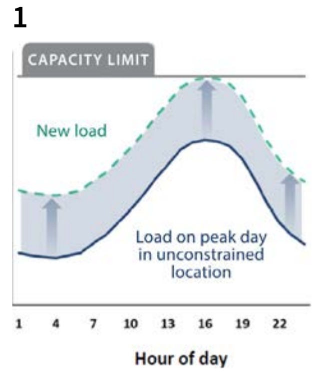
Grid Management Improvements

Because the power system (generation, transmission and distribution) is built to serve infrequent spikes in demand, less than half of its capacity is used throughout the year based on analysis of transmission areas defined by utilities and zones covered by RTOs/ISOs. This provides an opportunity to increase system utilization and reduce investment required to accommodate growing demand.

If new electricity demand can be added to the existing power system where and when there is spare capacity, the system's fixed costs will be shared by more customers, putting downward pressure on rates. By increasing annual system utilization by 10%, the new load is integrated at lower-than-average costs. Relative to current conditions, rates for all customers can be reduced by 3.4% (or by 4.8% relative to the status quo load growth scenario). Assuming annual U.S. electricity sales increase by 30% over the next five years, this would result in consumer savings of $170 billion on electricity bills over 10 years due to system utilization improvements. Additionally, utility earnings would increase and connecting the new load to the power system could be accelerated by several years.[20]

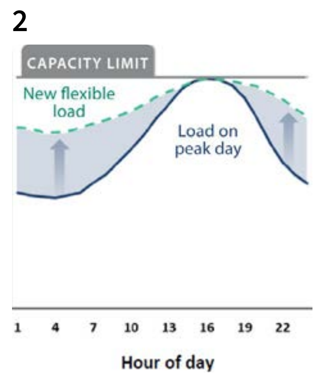
Higher system utilization while demand is growing can be accomplished in three ways (Figure 15). New load can be added at locations with existing headroom, new load can be added at times with spare capacity, or incentives can reduce existing demand at system peaks. There are a number of tools available today that can increase grid utilization (Figure 16).

1



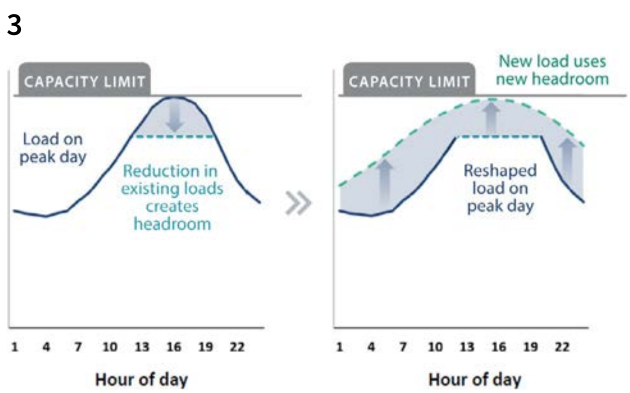
Add new load in locations where sufficient headroom already exists on the system.

2



Add new load at times when there is spare capacity. This is possible if the new customers are flexible and/or can self-supply during peak conditions.

3



Incentivize technologies and behavioral changes that reduce peak demand of existing load. This creates new headroom on the system, which can then accommodate the addition of new load.

Figure 15. Three Ways to Increase System Utilization.
Source: Brattle Group, "The Untapped Grid" (March 2026)

TOOLS	IMPACT
Batteries	Batteries can charge from the grid at times when there is spare capacity, and discharge to the grid to create headroom during peak hours.
HVAC Controls	HVAC controls allow heating and cooling to be reduced during a limited number of hours per year when demand for electricity is highest using smart thermostats.
EV Charging Controls	EV charging controls can shift electric vehicle charging load to hours when there is excess system capacity (e.g., overnight hours).
Smart Panels	Smart panels are an emerging technology to manage customer demand through circuit-level monitoring and control.
Time-Varying Rates	Time-varying rates provide customers with a financial incentive to shift consumption to off-peak hours.
Flexible Interconnection Policies	Flexible interconnection policies are agreements between the utility and the customer to operate the customer's load within prescribed limits (operating envelopes).
Targeted Energy Efficiency	Targeted energy efficiency focuses efficiency investments on locations and end uses where they provide the greatest grid value, such as constrained feeders or peak-driven substations.
Grid-Enhancing Technologies	Grid-enhancing technologies increase the usable capacity of existing transmission and distribution assets through advanced monitoring, control, and power flow optimization.
Data Center Flexibility	Data center flexibility can directly reduce the power system impact of large loads through operational adjustments or the use of on-site generation (i.e., Texas Senate Bill 6).

Figure 16. Tools to Increase Grid Utilization Available Today.
Source: Brattle Group, The Untapped Grid (March 2026)

Future Technology Developments

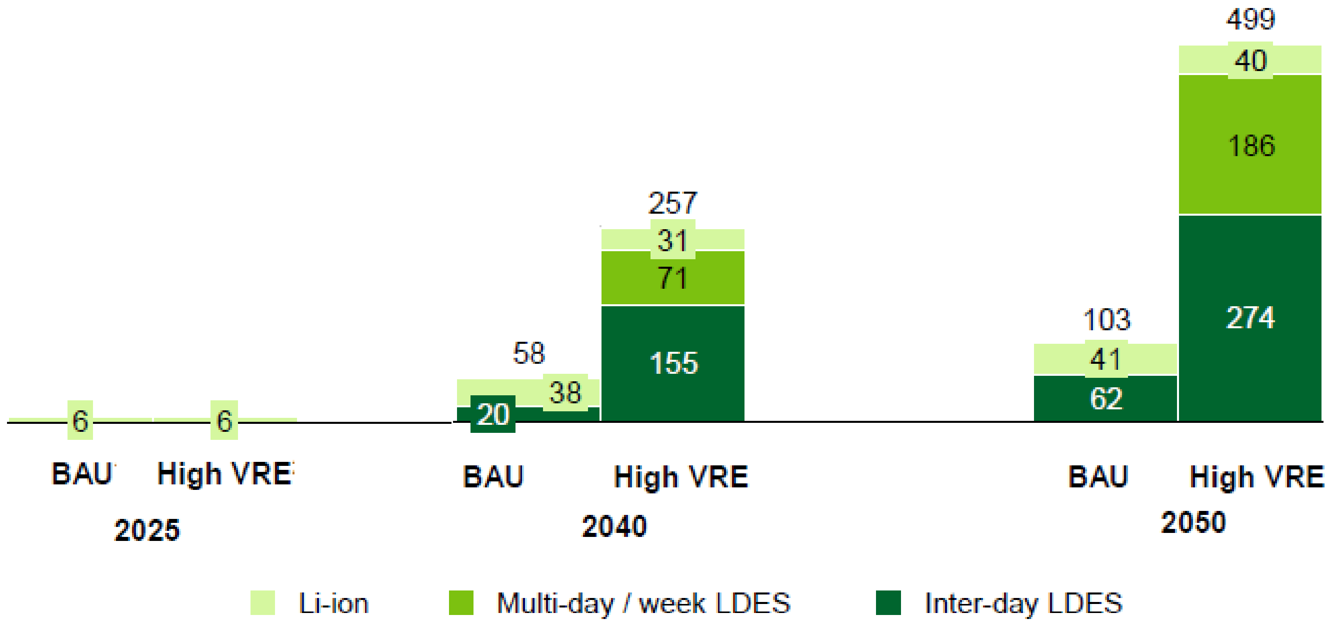


Figure 17. Potential U.S. Deployment of Long Duration Energy (GW) Storage.
Source: DOE, "Pathways to Commercial Liftoff: Long Duration Energy Storage" (March 2023)

Two major potential technology improvements could dramatically reshape the future of the U.S. electricity grid: cost-effective long duration energy storage (LDES) and advanced grid technologies.

Based on analysis by the U.S. DOE, the U.S. grid may need between 225 GW and 460 GW of LDES capacity for power market applications for a net zero economy by 2050, representing $330 billion in cumulative capital (Figure 17). While this requires significant investment, analysis shows that by 2050 LDES expansion would result in between $10 billion and $20 billion in annualized savings in operating costs and avoided capital expenditures.

The focus of LDES is defined as shifting power by between 10 hours and 36 hours and includes most mechanical storage technologies and some electrochemical technologies (e.g., flow batteries). These technologies primarily serve a diurnal market need by shifting excess power produced at one point in a day to another point within the same or next day. Multi-day/week LDES is defined as shifting power by 36–160+ hours and includes thermal and electrochemical technologies. It fills a market and end-use customer need where there may be an extended shortfall of power (e.g., multiple days of low wind and solar or resiliency applications) several times per year; multi-day/week LDES can also reduce the required curtailment/interconnection overbuild to support variable renewables.

Duration	Energy storage form	Technology	Nominal duration, hrs	LCOS[5], $/MWh	Min. deployment size, MW	Average RTE, %	TRL
Inter-day	Mechanical	Traditional pumped hydro (PSH)	0–15	70–170	200 – 400	70–80	9
		Novel pumped hydro (PSH)	0–15	70–170	10–100	50–80	5-8
		Gravity-based	0–15	90–120	20–1,000	70–90	6-8
		Compressed air (CAES)	6–24	80–150	200–500	40–70	7-9
		Liquid air (LAES)[1]	10–25	175–300	50–100	40–70	6-9
		Liquid CO2[1]	4–24	50–60	10–500	70–80	4-6
Multi-day / week	Thermal	Sensible heat (e.g., molten salts, rock material, concrete)[2]	10-200[2]	300	10–500	55–90	6-9
		Latent heat (e.g., aluminum alloy)	25–100	300	10–100	20–50	3-5
		Thermochemical heat (e.g., zeolites, silica gel)	XX	XX	XX	XX	XX
	Electrochemical	Aqueous electrolyte flow batteries	25–100	100-140	10–100	50–80	4-9
		Metal anode batteries	50–200	100	10–100	40–70	4-9
		Hybrid flow battery, with liquid electrolyte and metal anode (some are Inter-day)	8–50[2]	XX	>100	55–75	4-9

Figure 18. Long Duration Energy Storage Technologies.
Source: DOE, Pathways to Commercial Liftoff: Long Duration Energy Storage (March 2023)

Long duration energy storage systems provide three primary, market-related benefits:

- LDES technologies support and complement the expansion of variable renewables.
- LDES can enhance grid resiliency and reduce the need for new natural gas capacity.
- LDES can diversify the domestic energy storage supply chain. While these technologies will potentially require new supply chain elements, many have little to no reliance on hard to source raw materials (e.g., mechanical technologies).

LDES technologies can be divided into three groups based on physical characteristics: mechanical, thermal, and electrochemical. They exhibit a range of maturities based on readiness to be deployed beyond the lab (Figure 18). Mechanical technologies are generally the most mature, and some are already in the commercial demonstration stage. Mechanical technologies typically require a relatively large minimum size for a demonstration project (i.e., 50–100 MW costing $100 million or more). Thermal technologies used in power applications are moving into commercial demonstrations and also require large demonstration projects. Although many electrochemical technologies are "in lab" or in pilot testing, they can be deployed and tested in smaller, discrete projects and in conjunction with other technologies. This flexibility means that electrochemical technologies are moving into several first-of-a-kind (FOAK) commercial demonstrations that may lead to more rapid iteration and innovation versus other technologies.[21] Sodium ion batteries specifically appear to be a viable technology in high-heat environments such as deserts, where the cooling load for a traditional lithium ion "big battery" is cost-prohibitive.[22]

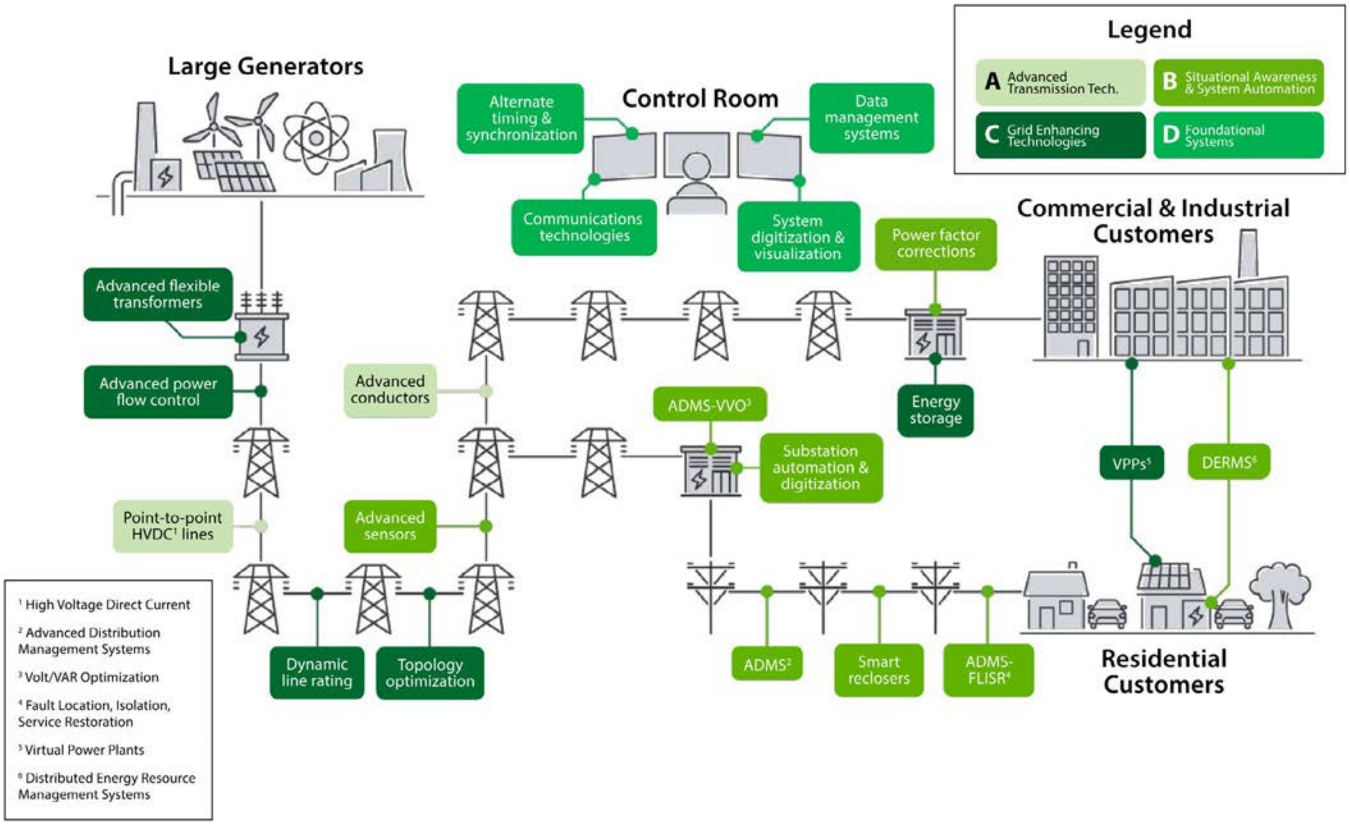


Figure 19. Advanced Grid Technologies.
Source: DOE Pathways to Commercial Liftoff: Innovative Grid Deployment (April 2024)

Multiple advanced grid technologies are likely to be available to address near-term hotspots and modernize the grid (Figure 19). These technologies include four categories that apply across the transmission and distribution system:

- Advanced transmission technologies that expand firm line capacity.
- Situational awareness and system automation solutions that improve visibility and decision-making.
- Grid-enhancing technologies (GETs) and applications that improve system utilization and performance.
- The foundational systems necessary to enable advanced technologies and a modern grid.[23]

Deploying these technologies could increase capacity significantly in excess of expected demand growth (Figure 20).

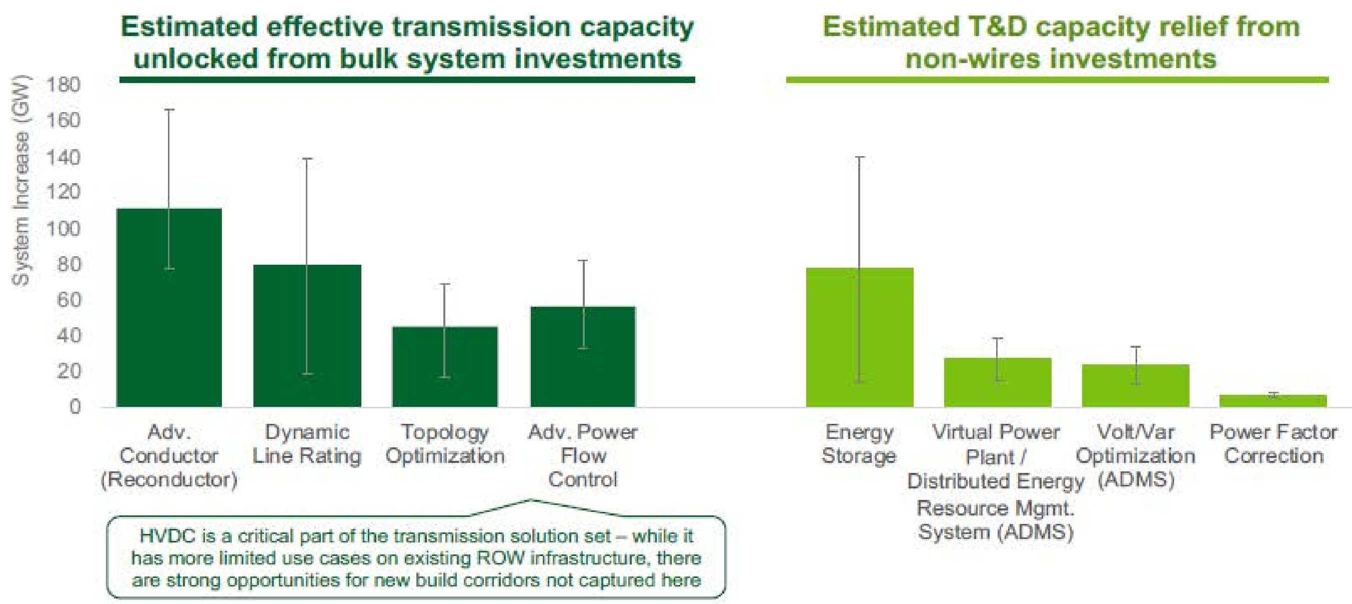


Figure 20. Capacity Impact from Full Advanced Grid Technologies Deployment.
Source: DOE Pathways to Commercial Liftoff: Innovative Grid Deployment (April 2024)

> Cost-effective long duration energy storage and advanced grid technologies are two major potential technology improvements that may dramatically reshape the future of the U.S. electricity grid.

Other Challenges

Several emerging issues inject additional uncertainty into demand, especially from data centers. The first is water consumption. Data center developers are increasingly tapping into freshwater resources to quench the thirst of data centers, which use the water directly for cooling and indirectly for fossil fuel power generation. That puts the water supply of nearby communities at risk and has sparked large-scale protests against the centers, which can consume up to 5 million gallons per day, equivalent to the water use of a town with between 10,000 and 50,000 people.

As data centers use more energy for operations and to meet AI requests, they consume larger amounts of water to cool their processor chips in order to avoid overheating and potential damage. This excludes indirect water use in thermal power generation that often supplies the power to the data center and water used in chip manufacturing. Additionally, although approximately 80% of the water (typically freshwater) withdrawn by data centers evaporates, the remaining water is discharged to municipal wastewater facilities. The large volume of data center wastewater may overwhelm local treatment facilities.[24]

This problem is likely to be particularly acute in the western U.S. A report last year estimated that data centers across Arizona, Colorado, Nevada, New Mexico, and Utah could use 7 billion gallons of water annually by 2035, enough to meet the annual needs of up to 194,000 people, just for on-site cooling.[25] There are similar concerns in ERCOT. Currently, data centers consume about 3% of the water used in Texas. A recent study by UH projects that this share could grow to about 10% of water use in the state over the next decade, driven by direct (for cooling) and indirect (for electricity generation) water use related to data centers, depending on the data center growth rate and the generation mix used to meet their electricity demand.[26] Recent modeling by Compass in conjunction with the University of Texas shows that data center direct and indirect power generation water use will average nearly 6% of all Texas water use by 2040 under a range of scenarios, with extreme cases indicating as much as 9%.[27]

Data centers in Arizona, Colorado, Nevada, New Mexico, and Utah could use 7 billion gallons of water annually by 2035, which is enough to meet the annual needs of up to 194,000 people, for on-site cooling.

Today, data center developers most commonly choose to withdraw water from freshwater sources and employ water-intensive practices, such as air cooling through water evaporation. However, there are options which can reduce water consumption. These include the following:

- Closed-loop cooling systems enable the reuse of both recycled wastewater and freshwater, allowing water supplies to be used multiple times. A cooling tower uses external air to cool the heated water, allowing it to return to its original temperature. These systems can reduce freshwater use by up to 70%.
- Free cooling is a method where outside cold air is drawn into the data center to cool the equipment. Data centers must be located in cooler climates for this strategy to be effective.
- Air cooling involves air conditioning vents and tubes that remove heat generated by chips as they process data and AI requests. This is most effective in areas where electricity is cheaper and water resources are limited.
- Immersion cooling involves bathing servers, chips, and other components in a specialized dielectric (or non-conductive) fluid. Hardware is submerged in specially designed tanks filled with the coolant. The non-conductive liquid absorbs the heat from the chips and transfers it to a heat exchanger, where it is cooled before flowing back into the tank. Immersion cooling entails higher upfront costs than conventional direct liquid cooling but provides significant energy savings and space-optimization benefits for data center developers.
- Using non-potable water sources like recycled wastewater and captured water.[28]

A second issue is community opposition due to increased water use and wastewater treatment requirements, noise pollution, competition for land, and visual aesthetics. At least seven in 10 Americans would now oppose a data center being built near their home, according to a new Heatmap Pro poll, a record high that reveals a staggering shift in public opinion against facilities powering the artificial intelligence boom. Now 55% of Americans — an absolute majority — "strongly" oppose a data center project built near where they live, and an additional 16% are "somewhat" opposed. Only 21% of Americans would support a new nearby data center. The public has swung 49 points against data centers in just nine months, underscoring the heightened political salience of the facilities and the AI industry they embody.[29]

Policy Opportunities

POLICY AREA	PRIMARY CHALLENGE	EXAMPLE OF POLICY TOOLS
Load Forecasting	Forecasting uncertain load growth to avoid over- or underbuilding grid infrastructure	Better data, scenario analysis, customer commitments and financial safeguards
Facility Permitting	Lengthy, fragmented permitting processes delay grid infrastructure development	Streamlined process, agency coordination, strict deadline and expedited reviews
Interconnection Process	Inefficient interconnection processes create queue delays and uncertainty	Cluster studies, firm study deadlines, financial and commercial readiness requirements
Markets & Operations	Maintaining grid reliability amid increasingly dynamic supply and demand	Demand response, dynamic pricing, fast-response resources and grid-support services
Cost Allocation & Ratemaking	Ensuring fair cost allocation for grid investments driven by large loads	Large-load tariffs, long-term contractual and financial commitments, exit fees
Mitigating Ancillary Impacts	Addressing local environmental impacts	Water, noise, land-use requirements, tax and tariff incentives

Figure 21. Summary of Challenges and Policy Options.
Source: Contributor Analysis

Federal, state, and local governments and agencies are grappling with the policy implications of the rapid growth and changing structure of the U.S. electricity grid. Many jurisdictions are actively considering or have implemented changes in laws and regulations designed to facilitate this change and avoid unintended consequences. These efforts are focused on a number of common challenges and policy options (Figure 21).

Load Forecasting

Changes in load forecasting processes focus on improving the accuracy of load forecasting given the increased uncertainty of future load and the risks associated with utilities underbuilding or overbuilding generation, transmission, and distribution infrastructure. A number of best practices have been proposed:

- Build forecasts from verified, geolocated data center inventories and historical performance data when available, reconciling interconnection queues with actual energization timelines to ground projections in reality.
- Use a range of scenarios to understand the realm of possibility (e.g., AI "bust" vs. AI "boom") and the impact of key levers.
- Leverage demand response to provide an operational buffer against volatility and uncertainty.
- Incentivize load flexibility, such as by offering faster interconnection to customers who agree to curtail and/or shift load.
- Require load commitments and credit support for speculative customers to protect ratepayers. This can be achieved by using risk mitigation tools tailored to each stage of the project lifecycle to reduce stranded asset risk.[30]

Facility Permitting

Efforts to create more responsive permitting processes at the state and federal levels can ensure timely review and approval of proposed generation, transmission, and distribution facilities.

Permitting involves a complex network of federal, state, grid operator, and local agencies. Large projects involving federal lands or waters can involve National Environmental Policy Act (NEPA) reviews conducted by the U.S. Army Corps of Engineers or the U.S. Fish and Wildlife Service. The Federal Energy Regulatory Commission (FERC) has responsibility for large grid interconnections, interstate transmission and interstate natural gas pipelines, and supply generation facilities.

There is significant congressional and federal support for permitting reform. Executive Order 14318, "Accelerating Federal Permitting of Data Center Infrastructure," was issued in July 2025, and additional executive orders and pending congressional legislation focus on accelerating federal permitting.

Because permitting involves multiple agencies and laws, the national Council on Environmental Quality (CEQ) previously coordinated among them by implementing NEPA regulations, which created significant delays. To address this, the administration shifted the regulatory burden away from the unified, centralized guidelines by issuing Executive Order 14154, "Unleashing American Energy," which, among other things, directed the CEQ to rescind the regulations. Federal agencies, including FERC, can now use their own permitting guidelines for interconnection and the grid system.

At the same time, Congress is working on a number of major bills to make the permitting reforms durable. These include the SPEED Act (Standardizing Permitting and Expediting Economic Development Act), which would limit environmental reviews and litigation; the CERTAIN Act (Create Expedited Reviews to Transform American Infrastructure Now Act), which would set strict deadlines for federal agencies to review permitting applications; and The FREEDOM Act (Fighting for Reliable Energy and Ending Doubt for Open Markets Act), which would amend several energy statutes related to impediments to energy investments.

States also play a major role in ensuring adherence to a number of federal statutes involving air and water pollution, including the Clean Air Act and the Clean Water Act, as well as state statutes around utility interconnection and water use. Finally, county and city regulations cover land use, zoning, site development criteria, and construction or special use permits.

Interconnection Process

Process changes that aim to increase the transparency and certainty of distribution and transmission load interconnection processes, reduce speculative requests, and create faster, more flexible kinds of interconnection service, including options for interconnection customers to reduce connection times by building their own generation and transmission facilities.

FERC initiated work in this effort with FERC Order 2023, overhauling previous orders that specified first-come, first-served interconnection. This order represents the most significant overhaul of interconnection rules in decades for generators. It changes the interconnection rules through three primary mechanisms:

- Cluster Studies: Instead of studying projects one by one (serial processing), providers must now study them in annual groups (clusters). This allows engineers to identify network upgrades that benefit multiple projects simultaneously and split the costs among them.
- Stricter Financial Readiness: To enter a cluster, developers must pay study deposits, demonstrate they own or rent the property at issue in the proposed development, and pay withdrawal penalties.
- Firm Deadlines for Utilities: Historically, utilities were only required to use "reasonable efforts" to complete studies on time — a standard so vague it was effectively unenforceable. Order 2023 replaces this with firm deadlines and financial penalties for transmission providers that fail to complete studies on schedule.[31]

ERCOT was one of the first to implement new interconnection processes in line with the FERC 2023 principles via Texas Senate Bill 6 in 2025. SB 6 issued a series of directives for the Public Utility Commission of Texas (PUCT) and ERCOT, including adoption of rules to reform interconnection processes and large-load financial contributions to interconnection costs, implementation of curtailment requirements for certain large loads through a demand response procurement program, and developing demand management and reliability services. SB 6 also requires the PUCT to evaluate current transmission allocation processes to ensure all loads appropriately contribute to recovery of transmission costs.[32]

ERCOT has subsequently developed a "batch process" for interconnection requests, with applications for the first batch due in mid-2026.

Another possible improvement would include establishing a single, unified cluster study interconnection queue that includes both generation and large demand side loads. Separate queues can potentially lead to coordination failures that undermine system planning. FERC could require large-load interconnection requests to include firm power purchase agreements or equivalent commercial commitments before entering the queue, mirroring FERC Order 2023's financial security requirements for generators.

Power markets are adapting to the influx of intermittent renewables and massive large loads (like data centers and AI computing) by shifting from rigid baseload planning to flexible capacity markets, dynamic pricing, and strict grid reliability standards.

Markets and Operations

New rules under consideration provide greater operational flexibility through changes in real-time energy markets and transmission service to manage intermittent generation sources, large-load demand variability, and virtual power plants. Power markets are adapting to the influx of intermittent renewables and massive large loads (like data centers and AI computing) by shifting from rigid baseload planning to flexible capacity markets, dynamic pricing, and strict grid reliability standards.

Grid operators and regulators are implementing critical changes to manage three main grid operational challenges:

- Accommodating Intermittent Power — market and operations changes include rewarding Fast-Frequency Response (FFR) generation sources such as grid-scale batteries and fast-ramping peaker plants, allowing solar and wind farms to actively control active power and frequency and creating operational rules to throttle back renewable output during over-generation periods, preventing grid congestion.
- Integrating Massive Loads — changes include incentivizing or requiring large data computational facilities (including data centers and crypto miners) to reduce consumption or shift workloads spatially and temporally during extreme peak demand events and encouraging on-site generation.
- Market Evolution and Regulatory Reform — exposing large-load customers to highly granular, locational marginal pricing (LMP), which incentivizes them to consume power during off-peak hours and self-hedge price volatility, and allows distributed energy resources, like smart thermostats, EVs, and home battery systems, to aggregate and compete in wholesale capacity and ancillary markets, essentially turning demand into supply.

Cost Allocation and Ratemaking

Focus is on new cost allocation methods with clear rules for how the cost of grid investments to accommodate new large loads will be allocated to avoid unfairly burdening existing customers with the costs and risks of underbuilding or overbuilding facilities to accommodate them. One way that regulators are seeking to manage this spillage is by developing or updating large-load tariffs that define electricity rates and terms of service for these customers. Some of the more common policies include:

- Full Funding of Large Loads: Implementing rules to ensure large-load developers fully fund required transmission and substation infrastructure, shielding residential ratepayers from the costs.
- Minimum Contract Term Lengths and Monthly Billings: Including the minimum length of time the large-load customer must operate under the tariff and its terms, and the portion of the customer's contract capacity they must pay demand charges for, regardless of usage.
- Collateral Requirements: Financial security or credit information to demonstrate creditworthiness and reduce the risk of default.
- Exit Fees: Compensation to the utility if a customer exits their contract early.
- Capacity Reassignment: The ability for a customer to transfer part of their contracted capacity and related financial obligations to another eligible customer.[33]

Mitigating Ancillary Impacts

Other policy initiatives are focused on mitigating the ancillary impact of load growth, especially from data centers. In addition to concerns about grid capacity and electricity rate hikes, local entities are increasingly voicing concerns about water use and wastewater treatment requirements, noise pollution, competition for land, and visual aesthetics, as well as the financial impact of sales, property, and corporate tax exemptions.

There is an opportunity for federal agencies such as FERC and the EPA to address these public concerns by jointly developing a federal framework requiring large electrical loads to disclose water consumption, Scope 2 greenhouse gas emissions, and air quality impacts as a condition of interconnection service.

State environmental agencies also could play a role by conditioning large-load interconnection approvals on compliance with state water quality, air quality, and noise standards, and by requiring environmental impact assessments for projects in sensitive or water-stressed regions. More importantly, federal and state tax incentives, accelerated depreciation, and other tariff programs could reward data centers that demonstrate high power usage effectiveness ratings, water recycling, and air-cooling technologies.

Federal agencies such as FERC and the EPA can address public concerns about water requirements, noise pollution, land competition, visual aesthetics, and tax exemptions by jointly developing a federal framework.

Conclusions

The U.S. electricity system is at a crossroads. Even though there are major uncertainties about how much demand will grow and how much generation and infrastructure technology will evolve, a major increase in grid planning and investment is required.

The fragmented nature of the U.S. grid and complex regulatory environment will make meeting this challenge difficult. Fortunately, there are policy solutions underway in many jurisdictions to accelerate the building of new generation capacity, including behind-the-meter capacity, and the interconnection of large loads like data centers.

However, far more work remains to be done. Significant market reform and regulatory initiatives will be required to fully utilize the existing grid infrastructure and minimize the cost of the build-out through increased deployment of renewable generation, expanded inter-regional and intra-regional transmission, integration of VPPs, and the deployment of new long duration storage and advanced grid technologies.

Beyond these complex technical and regulatory issues, other stakeholder issues increasingly demand to be addressed. Those include community pushback on locating data centers in certain areas due to concerns about water use and other ancillary effects, as well as ensuring that investment burdens are fairly shared among grid customers.

The U.S. electricity system needs a major increase in grid planning and investment.

Significant market reform and regulatory initiatives will be required to fully utilize the existing grid infrastructure and minimize the cost of the build-out.

Notes

About UH Energy

UH Energy is the University of Houston's signature energy initiative, integrating research, education, industry engagement and innovation to address the most pressing energy challenges of the 21st century. Located in the energy capital of the world, UH leverages multidisciplinary expertise across engineering, science, business, law and public policy to develop reliable, affordable, resilient and sustainable energy solutions. UH Energy brings together UH's energy-related talent and resources to produce a highly skilled workforce and strategic leadership for the evolving sector. It is recognized for research breakthroughs and technological innovations that drive today's energy industry. This integrated approach spans the full energy system spectrum—from traditional hydrocarbons to renewables and emerging technologies—all guided by UH's role as The Energy University®.

About GEMI

The Gutierrez Energy Management Institute (GEMI) is responsible for the energy education program at the C. T. Bauer College of Business at the University of Houston. GEMI partners with the energy industry by developing and placing future leaders with relevant knowledge and experience of the industry, undertaking research in business matters of interest to the industry, and providing opportunities to discuss relevant issues in a neutral setting.

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