REPORT

Electricity Demand Growth:

How Will the Grid Keep Pace?

Summary 3

Electricity Demand Growth Projections 5

New Generation. 10

Transmission Investment 13

Demand-Side Resources 16

Recommendations 18

Summary

The next phase of U.S. electricity demand growth will be defined less by how much demand rises and more by whether the power system can deliver.

High demand forecasts remain a major concern for energy stakeholders, but the more important questions are now: **Where can new demand be served? At what scale? And how quickly?**

Demand only translates into economic growth when the grid can support it. New data centers, industrial facilities, and electrified buildings and transportation all depend on the same basic condition: enough power, in the right place, at the right time. Without it, projects are delayed, costs rise, and growth slows.

ICF projects total **U.S. electricity demand** will increase **21% by 2030** and **39% by 2035 from 2026 levels**. Demand during peak periods, when the grid is under the greatest stress, is also expected to climb sharply—**up 14% by 2030 and 25% by 2035**. These pressures will not be evenly distributed. The greatest strains are likely to emerge in regions that are already constrained and seeing the fastest growth in data center development.

The U.S. has limited capacity to absorb this growth. ICF analysis finds only about **26 GW of excess generating capacity** above minimum reliability needs, equal to roughly **3% of total U.S. capacity**. In high-growth markets like ERCOT and PJM, there is no spare capacity to support new demand beyond next year. SERC and NYISO could face similar constraints within the next few years.

Meeting this demand will require more than adding generation. Whether new capacity translates into reliable service will depend on the system's ability to deliver power where demand is growing.

A large generation buildout is underway, but timing and scale are critical. ICF forecasts **445 GW of U.S. generation capacity additions from 2026 through 2030,** yet only **68 GW is expected in 2026**. Additions will need to scale rapidly later in the decade to keep pace with demand. Just as important, not every new megawatt contributes equally when the grid is under stress. Some resources provide less value during peak periods, so the effective capacity added to support reliability is much lower than the headline total.
On a peak basis, the 445 GW of planned additions contributes only about 191 GW.

Transmission and distribution investment is also increasing, but grid infrastructure takes time to plan, permit, interconnect, finance, and build. That creates a core mismatch: new loads are seeking service now, while the generation and grid infrastructure required to serve them may take years to come online.

Demand flexibility can help close the gap in the near-term. Demand-side programs and flexible large-load operations can reduce pressure during the most constrained hours and in the most constrained locations. While not a substitute for new generation, transmission, or grid investment, they are among the fastest and most cost-effective tools utilities can use while larger infrastructure solutions are built, and they can play a long-term complementary role.

This report identifies where these pressures are likely to emerge first and what it will take to align new demand with available supply. The central question is no longer just how much electricity demand is forecast, but how much demand can realistically be served—and where. The answer will shape where economic growth occurs, how reliably customers are served, and what they ultimately pay.

In this environment, the advantage will go to those who can align demand, infrastructure, and timing—before constraints determine the outcome.

U.S. electricity demand is expected to grow

21% by 2030

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445 GW

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2030

But only 68 GW

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and not all new capacity contributes equally during peak demand.

Confidence and Visibility Rise in Electricity Demand Growth Projections

For the past several years, utilities and grid operators have been facing a surge of large load interconnection requests from data center developers seeking the fastest path to power. Many requests were overlapping, speculative, or difficult to verify, making it harder to determine which projects were likely to move forward.

That process is beginning to mature. Utilities and grid operators are strengthening large load interconnection rules, introducing specialized tariffs, and requiring stronger financial commitments from developers. Already, 30 states have approved large load tariffs, with proposals pending in four more. Utilities are also adding stricter readiness requirements, diligence standards, and withdrawal penalties to separate viable projects from speculative requests. Uncertainty is still inherent in demand forecasting, but these changes are giving utilities and grid operators better visibility into which large loads may move forward, when they may come online, and what it will take to serve them.

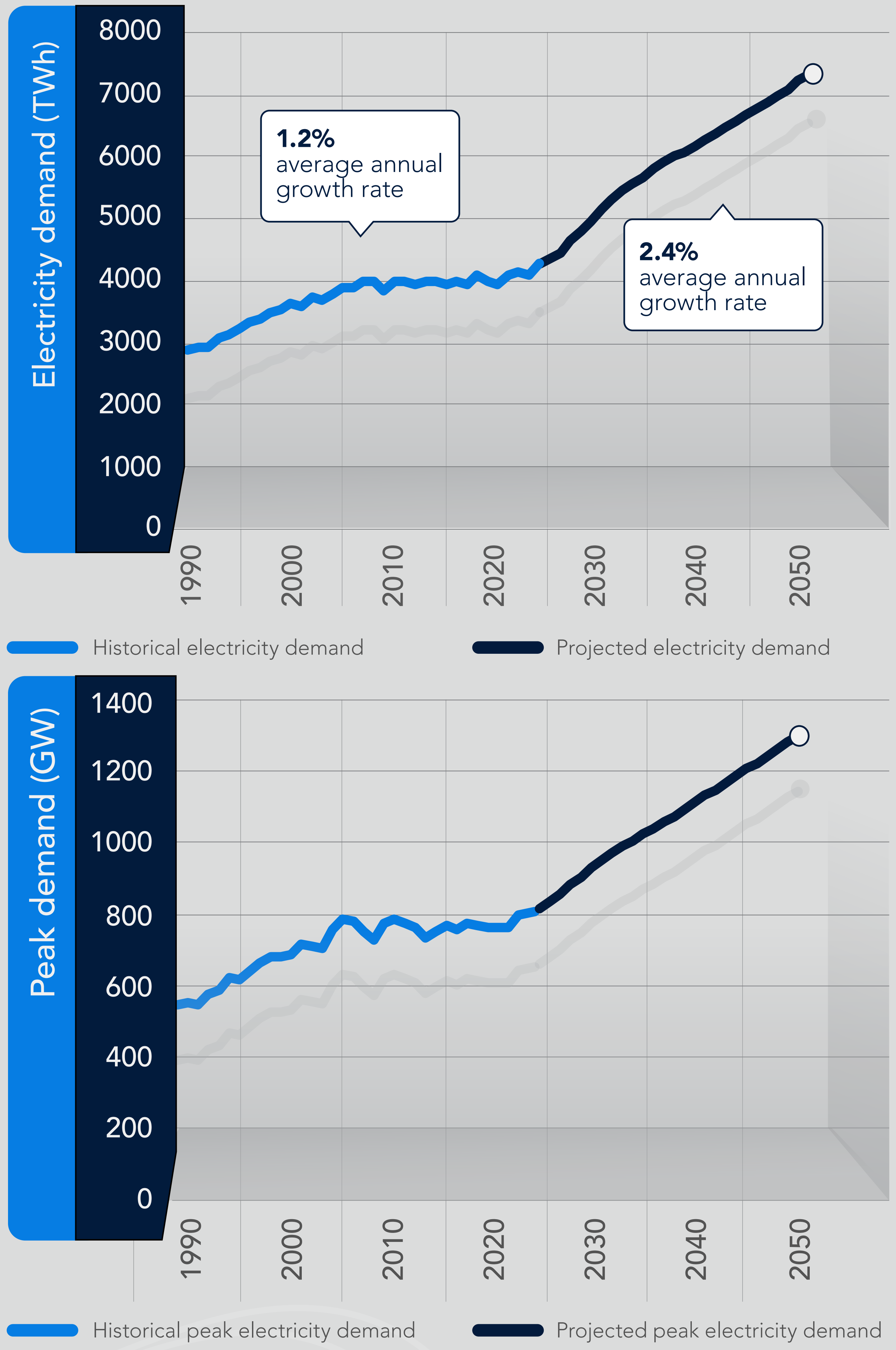
Long-term uncertainty remains high due to a wider band of ambiguity related to macroeconomic conditions, technology evolution, policy shifts, and load efficiency dynamics.

While uncertainty remains, ICF's outlook reflects current market signals and project execution trends. ICF projects total U.S. electricity demand will rise 21% by 2030 and 39% by 2035 from 2026 levels while U.S. peak electricity demand will grow 25% by 2035 and 57% by 2050 from 2026 levels, as shown in Figure 1.

Total electricity demand is growing faster than peak demand because many new load sources, especially data centers, consume power around the clock. These high-load-factor resources increase overall electricity use without increasing peak demand at the same rate.

Grid operators are also monitoring potential shifts in the timing of peak demand. Historically, summer evening cooling demand has driven system peaks in many regions. Expanding transportation and building electrification, combined with large load demand patterns, will change when and where peak conditions occur over time. For example, we project that Northeast markets will shift from summer peaking to winter peaking by 2040 on a weather-normal basis.

Figure 1: U.S. Electricity Demand and Peak Demand Growth



Source: ISO/RTO Forecasts, NERC ES&D, Utility IRPs, ICF

Notes: 1) Historical demand represents data from NERC ES&D from 1990 to 2024. 2025 represents forecast from NERC ES&D.

2) Q1 2026 represents ICF's demand projections from 2026 to 2050, based on data sources mentioned above.

Demand Growth Will Vary Significantly by Region

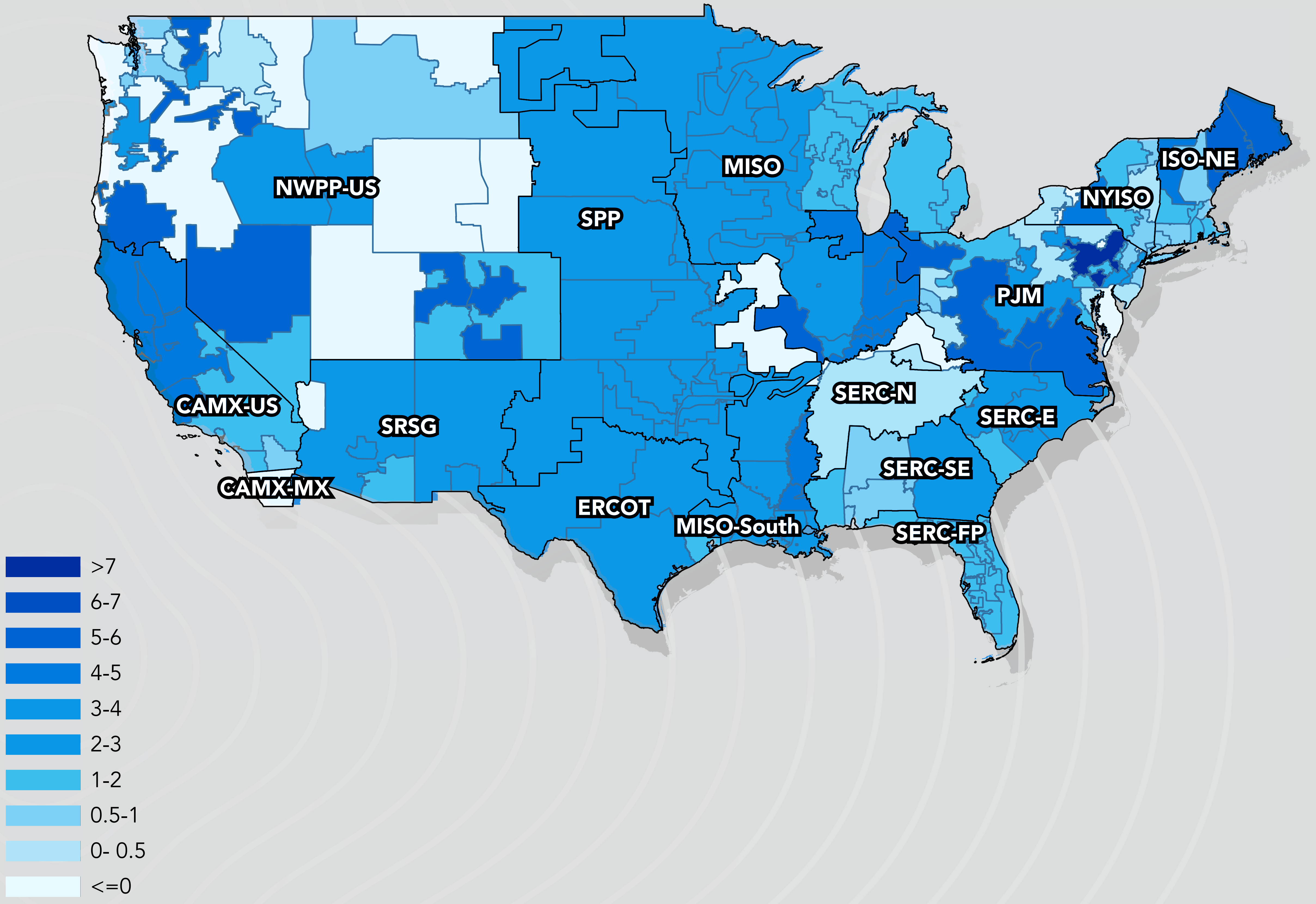
While total and peak electricity demand are expected to rise across the U.S., the increases differ substantially by region, as seen in Figure 2.

Grid operators and utility planners in regions with the highest forecast demand increases face the most daunting challenges to turn demand into serviceable load. Those regions must address tightening generation reserve margins and increased transmission congestion with significant infrastructure investment, while also pursuing flexible, lower-cost solutions that improve utilization of existing grid assets and customer-side resources.

However, they also face pressure from customers and policymakers to limit the rate increases needed to fund infrastructure investment and rising public opposition to the development of new large loads like data centers that are driving demand growth.

Figure 2: **U.S. Regional Electricity Demand Growth (2026-2035)**

Annual average electricity demand growth (%)



Source: Esri, TomTom, Garmin, FAO, NOAA, USGS, (c) OpenStreetMap contributors, GIS user community, and ICF

Demand growth variability:
A tale of 2 regions

In PJM, which spans 13 Mid-Atlantic and Midwest states and Washington, D.C., total electricity demand is expected to rise

43% by 2035

from 2026 levels.

By comparison, in NYISO, total demand is expected to rise

14%

over the same period.

Reliability Risks Are Rising as Spare Capacity Shrinks

Utilities and grid operators plan for more capacity than they expect to need on the highest-demand days. This planning buffer, known as a reserve margin, helps ensure reliability in all operating scenarios. Regulators will typically intervene to prevent reserve margins from dropping below these levels.

A reserve margin of about 15% above forecast peak demand is considered a minimum acceptable benchmark, though requirements vary by market. Reserve margins above this level indicate additional buffer against extreme weather risks, and the ability to absorb new load.

But in several high-growth regions, that buffer is getting thinner—or is already gone.

ICF projects several regions are already at resource adequacy minimums, as shown in Figure 3. As load growth has outpaced resource additions, any pre-existing excess capacity has quickly been absorbed.

There are several bottlenecks and supply-chain issues contributing to long lead times for the utility-scale generation and transmission expansions needed to keep pace with load growth:

- Long interconnection timelines
- Lack of distribution capacity at load hubs
- Siting and permitting hurdles
- Long order backlogs for key equipment
- Skilled labor shortages and workforce limitations

While the market is working to address equipment and labor supply chain issues, many of the other limitations could be alleviated through action by policymakers, regulators, and agencies at every level of government.

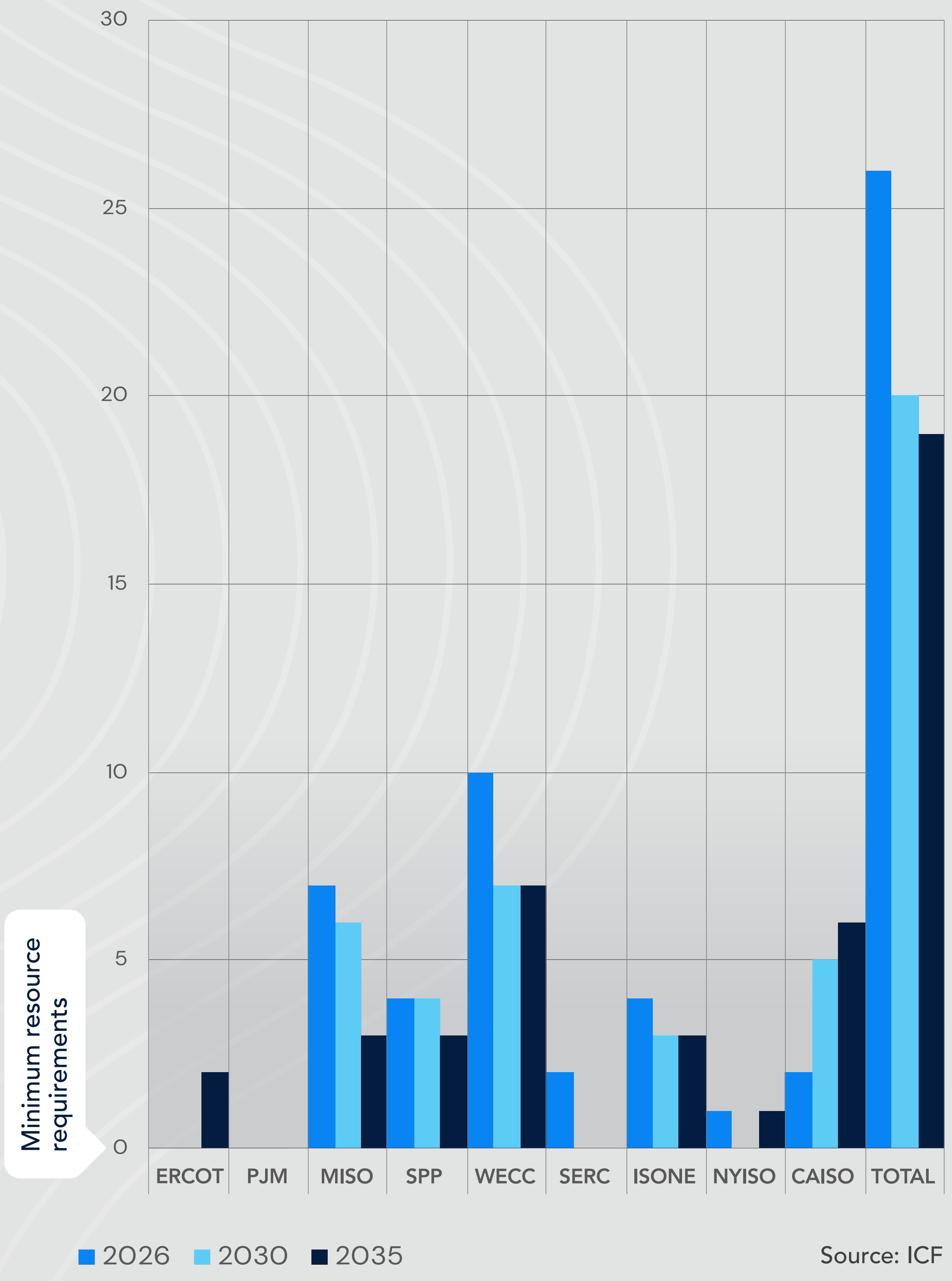
After accounting for required planning reserves, **the U.S. in total has only about 26 GW of excess generating capacity left as an additional cushion**.

That represents roughly 3% of total U.S. capacity beyond required planning margins.

This figure is already very low but is unlikely to fall to zero or become negative. This is largely because firm demand growth in high-growth regions with little or no excess capacity is likely to be constrained by the pace of new generation additions and the transmission needed to deliver that power. Any additional demand growth during this time will need to be non-firm, meaning the grid will not promise to serve it reliably and customers could be curtailed during periods of peak stress.

ICF forecasts that total cushion will fall to 20 GW by 2030, with most of the remaining spare capacity concentrated in regions with less data center interest. In high-growth regions, there is already little or no extra capacity available to absorb new demand. As a result, some new large-load interconnections are being delayed until enough infrastructure can come online to serve them reliably.

Figure 3: Regional Excess Capacity Above Minimum Resource Requirements (GW)



Source: ICF

Note:
Regions without a visible bar have no excess capacity above minimum resource requirements.

A tight electricity supply-demand dynamic is also a primary contributor to rising wholesale power prices, along with transmission congestion at critical points. Rising prices inevitably lead to affordability challenges for all electricity end users.

ERCOT and PJM have already reached the point of having zero excess generating capacity above minimum resource adequacy needs. SERC and NYISO are not far behind, with forecasts showing capacity could fall below minimum resource adequacy levels by 2030.

New Generation Is Scaling, but Timing and Location Matter

New generation investment is accelerating, supported by stronger market signals in many regions. For grids facing near-term capacity pressure, the key questions are practical:

- What types of generation will be built, and how much will they contribute to reliability during constrained periods?
- Where will that generation connect?
- How quickly can it come online, and what milestones or risks could affect that timeline?
- How much will serve the broader grid versus individual large loads behind the meter (BTM)?

> The timing challenge is clear: 2026 is expected to bring less new capacity than later years, even as large loads are seeking service now (Figure 4).

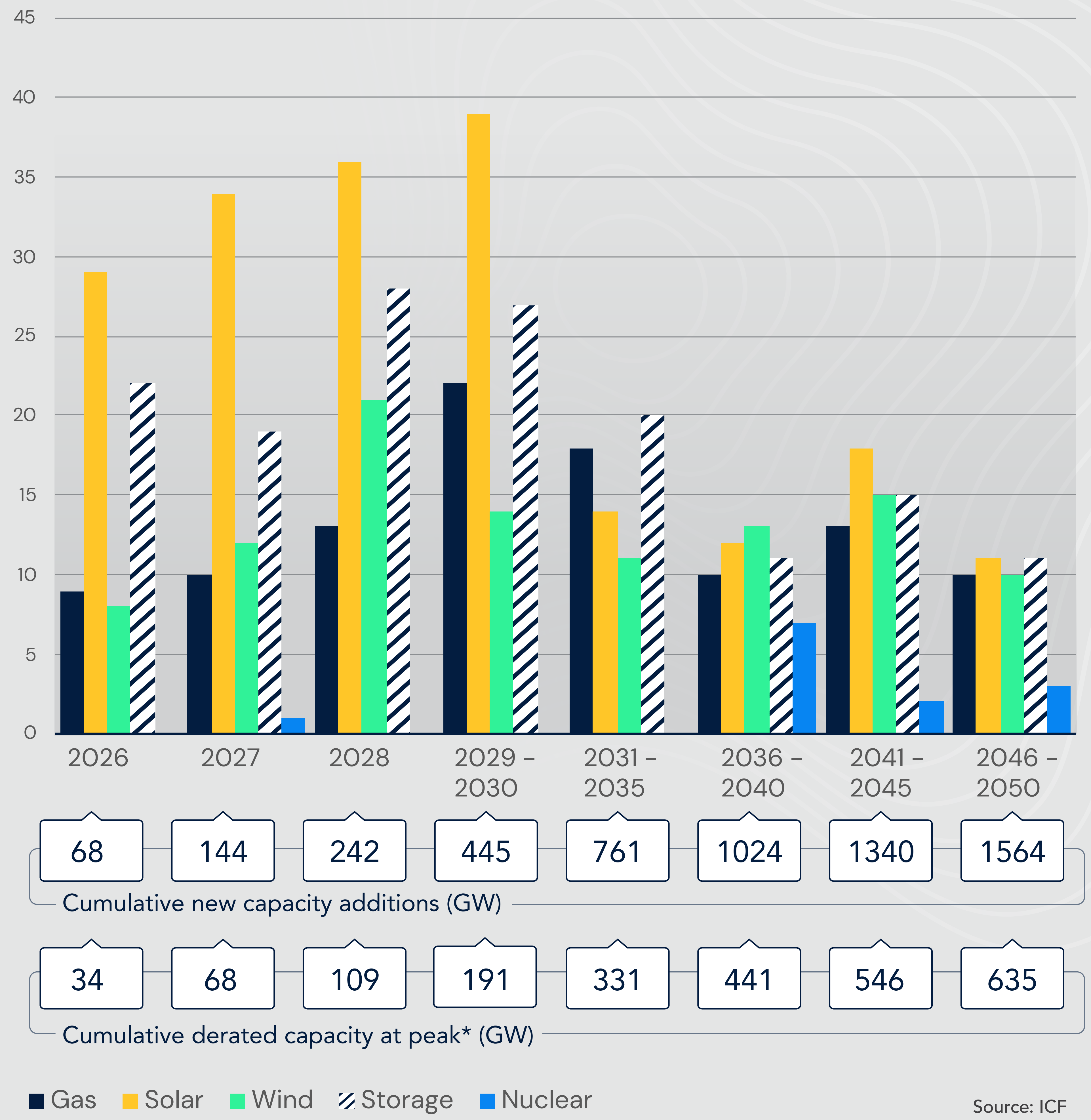
Progress and plans: ICF expects **68 GW of new generation capacity to come online in the U.S. in 2026**.

Additions increase to 76 GW in 2027 and roughly 100 GW per year in 2028, 2029, and 2030. In total, ICF expects 445 GW of new generation to come online from 2026 through 2030. Of that total, 88 GW is either under active construction or in testing phases today, and another 97 GW is fully permitted and under advanced development. While there are many projects in early-stage development, our forecast for 2030 implies that at least 260 GW of further capacity must advance quickly and begin construction in the next two to three years.

By comparison, the U.S. added 53 GW of new capacity to the grid in 2025, the highest amount of new capacity added in a single year since 2002 and up from 49 GW of new capacity installed in 2024.[1] This means the pace of new builds would need to roughly double from recent levels. The next one to two years show clear momentum, but if that pace cannot continue to increase, some demand additions may be delayed to preserve reliability.

[1] https://www.eia.gov/todayinenergy/detail.php?id=64586

Figure 4: U.S. Rate of Generation Additions (GW/Yr) by Resource



Source: ICF

*Estimated dependable capacity at peak reflects the portion of new capacity likely to be available when demand is highest.

Within this pool of generation, solar leads the pack with 29 GW of new capacity expected online in 2026 and 177 GW online in total by 2030 (Figure 4). Solar and battery storage are often developed together, as both a solution to renewable energy intermittency and to address peak demand challenges. ICF forecasts 120 GW of storage capacity coming online by 2030. Onshore wind has faced significant development challenges recently, and only 7 GW is expected to come online in 2026, but ICF forecasts that, with safe-harbored projects, a total of 62 GW will come online by 2030.

The rise of natural gas is another major trend in new U.S. generation supply. From a modest 9 GW of new gas generation expected to come online in 2026, ICF projects 77 GW of gas capacity to come online by 2030. Importantly, that does not reflect the large amounts of BTM generation being built by data center operators and other large load facilities. While limited disclosure makes national data difficult to assemble, recent announcements from data center hyperscalers make it clear that BTM additions could tally anywhere from dozens to 100 or more GW in the coming years.

These buildout numbers show that new generation is scaling. But capacity additions alone do not determine where and how quickly new load can be served. Several factors matter:

- **Capacity is not the same as electricity generated.** A gigawatt of solar and a gigawatt of combined-cycle gas do not produce the same amount of electricity over a year. Depending on market and operating conditions, 1 GW of solar may produce 1-3 TWh per year, while 1 GW of combined-cycle gas may produce 6-8 TWh per year.
- **Not all resources are equally suited to meet demand growth needs.** Even within a single resource type like gas generation, there are important quality factors to consider. Combustion turbines and reciprocating engines can be built faster but aren't as well-suited to serve the high load factors of data centers and some industrial facilities. Combined-cycle gas is a much better fit.
- **Location determines deliverability.** If new generation is not sited carefully, it may face long interconnection timelines before coming online. And even after it is built, transmission constraints can limit whether that power can reach growing load pockets.
- **Existing and onsite resources can also affect near-term serviceability.** In some regions, uprates, delayed retirements, life extensions, co-located resources, or BTM generation may help manage timing risk while new infrastructure is developed. These options will not eliminate the need for new generation, transmission, and distribution investment, but they can influence where and how quickly new load can be served.

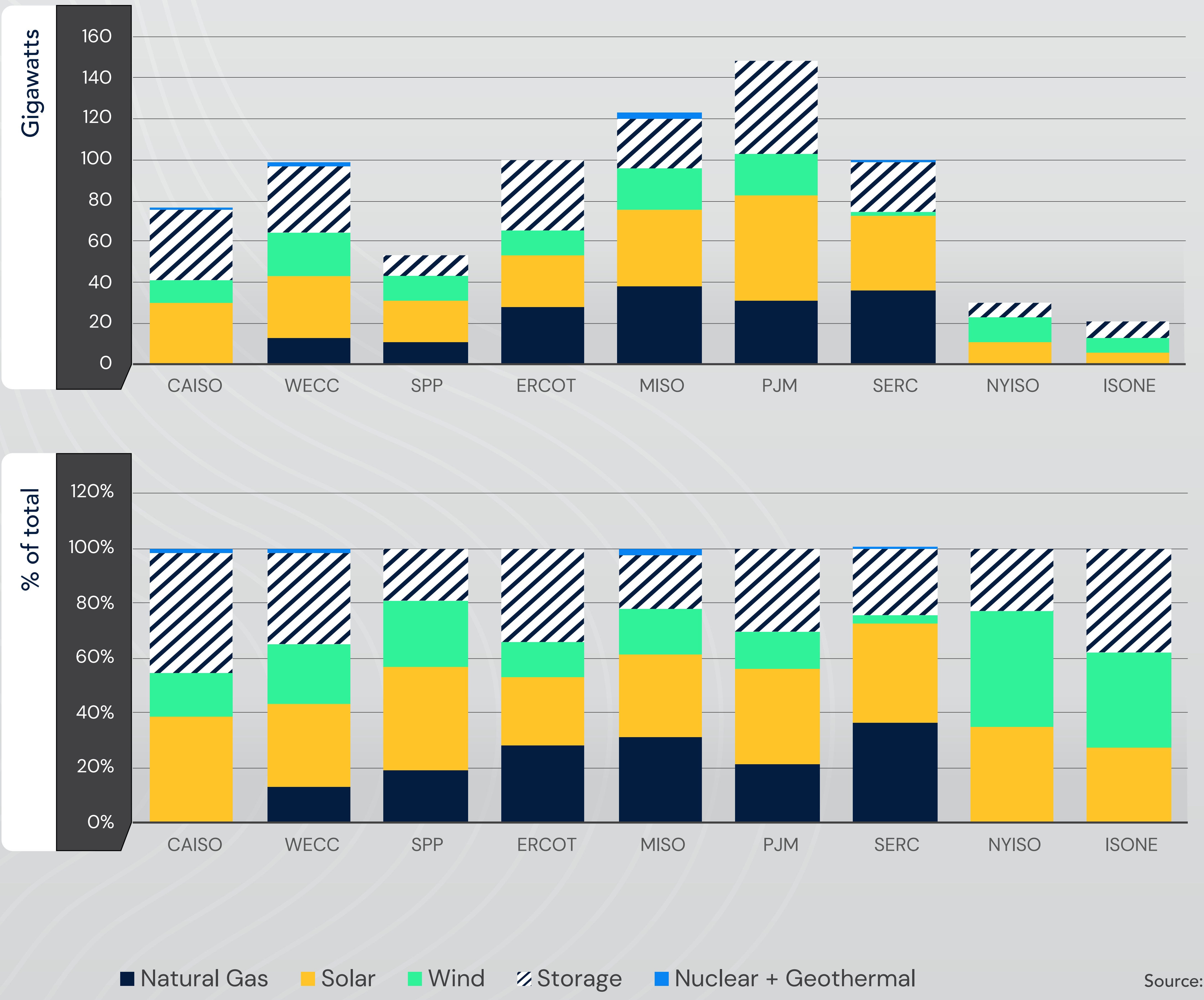
The Capacity Resource Mix Will Vary Significantly by Region

Each region in the U.S. is defined by different market conditions, policy environments, and load characteristics that determine the optimal path for building new generation resources.

In SERC, gas-fired generation is expected to account for 37% of new capacity through 2035. In CAISO, solar, wind, and battery storage are expected to account for 97% of new capacity over the same period, which comes as no surprise since California has a mandate to achieve 100% clean energy by 2045 and new gas power is extremely difficult to permit.

ICF projects that solar, wind, and battery storage will make up at least 60% of new generation capacity additions in every U.S. region through 2035 (Figure 5), but meaningful gas additions will also be needed to maintain reserve margins.

Figure 5: **Regional Capacity Additions by Resource Type (2026-2035)**



Source: ICF

Turning Transmission Investment Into Deliverable Capacity

Transmission investments have been growing steadily, with increasing levels of planned capital expenditures by utilities.

Transmission is a primary enabler of future load growth, but how quickly demand growth can be realized will depend not only on the sequencing and timing of major projects, but also on efforts to optimize the existing grid.

Progress and plans: U.S. investor-owned utilities are projected to spend about $178 billion on transmission investments between 2025 and 2028, according to the Edison Electric Institute. That is up from about $115 billion from 2021 to 2024. In recent years, much of this investment has focused on reinforcing and modernizing the grid to address aging infrastructure, reliability, generation interconnection, and other needs. Now, investment is also shifting toward meeting large load growth. DOE announced plans to support expansion of long-distance transmission line capacity by 16% by 2030, including building 7,500 miles of new transmission lines. This compares to approximately 450 high-voltage miles in 2023 and 900 miles in 2024.

While investment beyond 2028 is less certain, ERCOT, PJM, MISO, and SPP have recently approved large-scale transmission expansion plans to support demand growth. Many of these projects focus on extra-high-voltage lines and intra- and cross-regional integration to address reliability needs, interconnection needs, and congestion. However, rising planned investment is not the same as near-term deliverability. Large capital plans will not translate into timely relief in the highest growth areas without execution that navigates supply chain, siting, permitting, labor, and other challenges.

What more can be done?

In the interim, the grid must make better use of existing infrastructure. Grid-enhancing technologies (GETs), including dynamic ratings, advanced conductors, power flow control, and topology optimization, can increase utilization of existing corridors, but deployment remains limited.

Policy clarity is no longer the primary obstacle. FERC Order 881 requires transmission providers to use ambient-adjusted ratings, and FERC Order 1920 requires operators to consider GETs where they may be more cost-effective than traditional infrastructure. But recognition does not guarantee adoption. Cost recovery remains a key barrier. Utility recovery frameworks are still largely built around traditional capital investment. They do not always fit solutions that deliver capacity gains through software, operating changes, or lower-cost hardware. As a result, GETs can remain difficult to deploy even when they are technically sound, cost-effective, and aligned with regulatory intent.

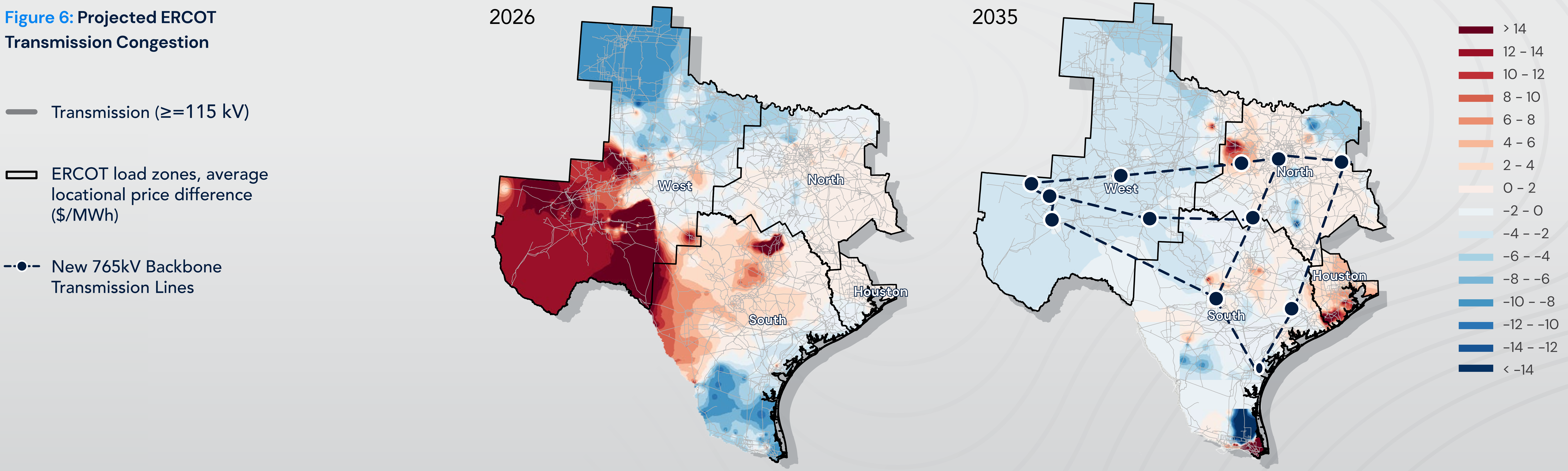
Finally, storage could play a larger role in relieving transmission constraints. The main barrier is the current revenue framework. Storage that earns regulated transmission revenue is typically precluded from participating in the energy markets, which limits its overall value compared with storage projects that can fully access market-based revenue streams. That tradeoff can discourage investment, even when storage offers clear grid benefits.

Regional Score Card: Beyond differences in demand growth, regions can also be differentiated by their relative “readiness” to serve new load—reflecting a combination of available capacity, transmission deliverability, and the timing of planned infrastructure additions. In the near term, this readiness varies significantly across markets and, in many cases, within subregions, reinforcing that the ability to serve new load is increasingly a localized and time-dependent question rather than a system-wide one.

ICF modeling indicates planned investments will help reduce congestion and improve deliverability in several regions. Yet, in some regions, other measures will be needed to supplement in the near term.

In ERCOT, for example, ICF projects demand to grow by 53% by 2035 relative to 2025 historical levels, reflecting an additional 45 GW of load. Recent investments have addressed localized constraints in the Houston area and further south. The new 765 kV transmission network will resolve the remaining severe constraints between West Texas and the rest of the market (Figure 6).

Figure 6: Projected ERCOT Transmission Congestion



Source: ICF

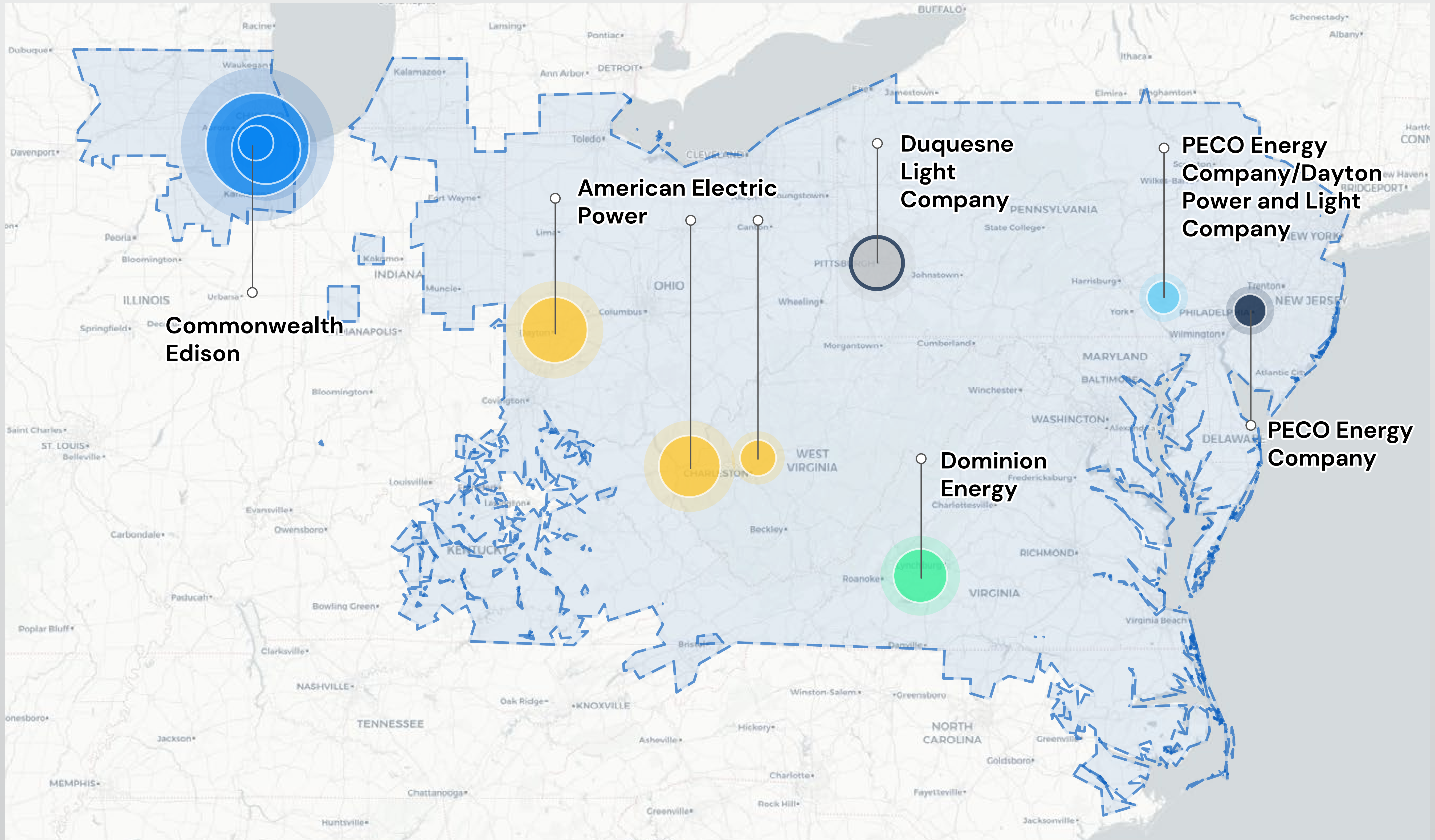
In PJM, the system operator recently approved a transmission expansion plan focused heavily on the Northern Virginia area, home of the world's largest concentration of data centers. As shown in Figure 7, ICF's analysis indicates that other preferred and emerging data center hubs in areas such as Chicago (Commonwealth Edison) and Ohio (AEP) are now projected to experience increasing transmission bottlenecks, with load growth averaging over 5% annually in both regions over the next ten years. These will likely be the focus of future transmission expansion plans. Because of the mismatch between the pace of transmission development and the rate of data center load growth, planners should explore the use of other solutions such as GETs that can bridge the gap. Measures such as conditional interconnection service and flexible load interconnection can also speed interconnection of large loads while transmission planning is catching up.

Figure 7: High-impact Transmission Bottlenecks Across the PJM Grid

Larger bubbles indicate constraints that affect a broader portion of the surrounding grid network

Busses impacted

556 busses | 200 busses | 55 busses



Source: ICF

Demand-Side Resources Can Help Bridge Near-Term Gaps

Demand-side resources will play a growing role in meeting electricity demand, especially during peak and stress periods when the grid is most constrained. They can also provide critical near-term capacity when infrastructure barriers and long lead times limit how quickly new generation and grid upgrades can come online.

These resources complement generation and transmission by bringing customer-side capacity, reducing peak demands, and improving use of existing infrastructure—helping more load be served within the system already in place. They can also move faster than many large infrastructure projects. In many cases, demand-side management (DSM) programs can be launched within 90 days of regulatory or utility approval.

> **The important question is not whether demand-side resources have potential. It is how much of that resource materializes when the grid needs it.**

Plans and progress: Utilities and distributed energy resource (DER) providers are increasingly showing that demand-side resources can deliver measurable reductions at the scale, consistency, and performance levels planners need.

One large Southwest utility's commercial program delivered approximately 130 MW of peak reduction, equal to about 3% of the utility's peak demand. Another large utility in MISO is demonstrating how better event design can make smart thermostat programs more consistent and more valuable as a grid resource. The program improved performance during the weakest hour of a four-hour event, when load reductions often fade, increasing reductions from 0.6 kW to 0.85 kW per customer account. Customer opt-outs also fell from 33% to 26% under similar event conditions, making the resource more dependable without increasing customer disruption.

By coordinating approximately 60,000 customer smart thermostats, the utility also has better visibility into how much load reduction the program can reliably deliver. That confidence allows the utility to use a portion of the flexible capacity to reduce market costs and pass savings on to ratepayers.

SMECO
Southern Maryland Electric Cooperative

Southern Maryland Electric Cooperative (SMECO) offers a constructive example of what can be achieved with full DSM buy-in. SMECO has enhanced its DSM capabilities through flexible load management strategies, including smart thermostat programs that support grid stability and reliability, water heater controls that provide grid flexibility, and electric vehicle programs that enable load management. From January to October 2025, the thermostat program shifted 622 MWh across 92 events. The water heater pilot achieved an average of 8.5 kW reduction per event and 1.06 MW of total demand reduction across 133 events in the same period. The EV charging pilot shifted 78 MWh over 106 events from May through September 2025, with over 93% of enrolled member EV charging occurring during SMECO's off-peak hours. Customer satisfaction with all three efforts remained high.

Learn more

These results signal a shift in how DSM is valued: from customer program potential to a dependable operational resource. Programs that can reduce peak demand at scale, sustain performance across the full event window, and participate in markets are more useful to planners and operators as capacity resources. They can help lower capacity needs, reduce capacity payments, and give utilities more flexibility to manage load growth while generation and grid infrastructure are still being developed.

Demand-Side Resources Are Maturing Into Dependable Grid Resources

Peak reduction at scale

~130 MW peak reduction from a single C&I load management program—equivalent to ~3% of utility peak demand, or powering roughly 100,000 residential homes.

More reliable event performance

Improved thermostat event design delivered stronger performance during multi-hour grid events.

Lowest-hour performance improved by more than 40%.

Customer opt-outs fell by 21%.

What more can be done? Utilities and other market operators can build on this progress by designing customer programs around dependable performance, not just enrollment. That means using better device-level data, customer targeting, dispatch controls, event design, and measurement practices to understand how much load reduction is available, where it is located, how long it can perform, and how consistently it responds under stressed system conditions.

This matters because reliability depends on the weakest hour, not the best hour. If a program delivers strong savings early in an event but fades later, planners and operators have less confidence in how much capacity it can provide. Programs that sustain consistent reductions across the full event window are more dependable as capacity resources and easier to integrate into grid planning and operations.

Utilities could continue advancing core DSM efforts, including energy efficiency, demand response, virtual power plants, managed charging, smart thermostat programs, and DER incentives. But the next phase requires a sharper focus on where and how these resources can provide dependable grid value. Programs should be targeted in constrained areas and designed for repeatable performance. Critically, they should also be integrated into planning so utilities can identify which demand-side resources can help serve near-term load growth and which gaps still require infrastructure investment.

Recommendations: Turning Forecast Demand Into Serviceable Load

Large load growth is no longer hypothetical; in many regions, it is now an execution challenge. The question is not whether new demand is coming, but whether it can be served reliably, affordably, and on time. Demand creates value only when it is translated into serviceable load through infrastructure readiness, disciplined planning, operational flexibility, and regulatory coordination.

Interconnection backlogs, grid constraints, permitting delays, equipment shortages, and fuel supply concerns are widening the gap between projected demand and deliverable power. Uncertainty around the timing, shape, and persistence of new load is adding to the challenge. As a result, the advantage is shifting to jurisdictions and market participants that can move most credibly from announced demand to actual service—not simply those that attract large loads.

Large-Load Developers, Generation Developers, Resource Planners, and Investors: Align Earlier to Deliver Faster

Faster service starts with earlier coordination on where projects locate, when demand ramps, how flexible the load can be, and whether the project is ready to finance. For large-load projects, that means providing clearer information sooner about when demand will arrive, how it will ramp, how the load will operate, and whether on-site or co-located resources are feasible. In constrained regions, those choices can shape upgrade needs, interconnection timelines, and the cost of service.

Generation developers and planners should align supply more directly with emerging large-load demand, focusing not only on capacity but also on location, deliverability, interconnection feasibility, and the reliability attributes needed to serve concentrated new load. In some cases, local generation, storage, or hybrid configurations may offer a faster path to service while larger network upgrades are pending. Earlier coordination between load and supply development can reduce delay and improve project readiness.

Investors, in turn, should further prioritize development assets with credible, near-term paths to execution. Projects that closely align load and supply are likely to command premiums because they may be less exposed to delay and more financeable than standalone developments that still need to secure buyers or sellers of power.

Transmission Developers, Owners, Planners, and Grid Operators: Close the Gap Between Planned and Deliverable Capacity

Transmission planners and operators are central to turning forecast demand into serviceable load. The challenge is not only load volume, but also timing, location, and uncertainty. Large-load growth is already congesting queues, creating contested upgrades, and raising questions about whether power can be delivered on timelines that often outpace traditional planning cycles. Planners need to distinguish speculative from committed demand, assess how large loads interact with existing system headroom, and coordinate with resource- and demand-side planning so decisions reflect where power is needed, how it will be delivered, and what flexibility is available.

Planners need to better connect forecast confidence to specific planning actions. That includes refining large-load readiness requirements, aligning load and supply studies with transmission expansion planning, and using more temporal analysis to assess deliverability under stressed and contingency conditions—not only annual adequacy. Planning criteria should place greater emphasis on attributes the system needs most, including flexibility and locational deliverability, and not just performance during peak conditions. More granular analysis of deliverability under stressed and contingency conditions, not only annual adequacy, should inform where and how expansion is prioritized. That sharper, granular analytical foundation also creates a natural opening for conditional firm service: by allowing load to interconnect on available headroom while transmission expansion is underway. Conditional firm can accelerate timelines without compromising system reliability—provided the curtailment terms and upgrade obligations are structured with sufficient clarity.

Realizing the potential of conditional firm service requires operational readiness. Utilities need the metering, telemetry, and control infrastructure to monitor and enforce curtailment obligations in real time, and the organizational alignment between planning and operations to ensure that what is approved on paper can be reliably managed in practice.

GETs and storage as transmission offer a faster and lower-cost path to expanding effective capacity on existing corridors and should be treated as preferred options in the planning toolkit.

Closer coordination with state agencies, regulators, and economic development leaders will be critical where policy goals, permitting, customer timelines, and grid constraints intersect. Transmission planners and grid operators can support that alignment by sharing practical metrics, including large-load interconnection timelines, equipment lead times, and other indicators that show whether integrated planning is shortening delivery timelines.

Customer Program Leaders, Aggregators, and State Program Administrators: Prove Performance, Not Just Participation

Program providers can help make demand-side resources more reliable, scalable, and valuable to the grid. To become relevant for system planning, these resources must meet the reliability criteria system planners require. That means exploring alternative funding sources, including investments from large-load developers, and designing DSM programs that increase participation without increasing opt-outs or creating poor customer experiences during peak events. It also means targeting load management and energy efficiency participation where it can have the greatest system impact.

Customer program leaders can design DSM portfolios around the same questions planners ask of supply-side resources: how much reduction is available, where it is located, how quickly it can be dispatched, how long it can perform, and how certain that reduction is under stressed system conditions.

Strong programs combine customer targeting, device-level data, event testing, and dispatch strategies to understand how resources perform under different conditions. They also reduce variability in customer behavior through shorter dispatch windows, pre-event communication, and comfort protections that lower opt-outs and improve repeat performance.

The next step is aggregating these resources into portfolios that deliver consistent, measurable reductions. Smart thermostats, managed charging, water heaters, commercial and industrial load control, battery storage, and other customer-sited resources do not need to perform identically to be valuable. But they do need to be coordinated, measured, and communicated in ways that give planners confidence in the total reduction available during constrained periods.

For program providers, the priority is no longer just increasing enrollment but proving dependable performance. Programs that can show when, where, and how they reliably reduce load will be better positioned to bridge near-term capacity gaps while generation, transmission, and distribution solutions are built.

Federal Agencies: Clear Delivery Bottlenecks

Federal agencies wield unique influence, from direct investment and financing programs to regulatory reform and interagency coordination. Because delivery and execution challenges span sectors, supply chains, and jurisdictions, federal action can address bottlenecks at scale.

Federal agencies can focus on the constraints that cut across regions, sectors, and jurisdictions. That includes:

- Advancing transmission corridor development, interconnection reform, and standardized approaches to infrastructure serving emerging load hubs.
- Supporting the fuel, storage, and firm capacity investments needed to maintain reliable service in constrained regions, including at critical large-load sites.
- Expanding the manufacturing, logistics, and workforce capacity needed to deliver grid infrastructure on time.
- Streamlining permitting, improving investment signals, and publishing timely data on interconnection queues, permit timelines, and equipment lead times.

DOE program offices, the Federal Energy Regulatory Commission, and other federal agencies can accelerate progress by aligning priorities with delivery constraints and the areas where delay is most costly. When federal action is grounded in delivery analysis, it can improve reliability, reduce costs, and shorten timelines.

State Agencies: Make Growth Ambitions Executable

States play a central role in determining whether forecast demand can become serviceable load. Doing so requires alignment across policy, infrastructure, permitting, and economic development—not just energy planning.

The challenge is not only setting direction, but balancing growth, affordability, reliability, and public acceptance of new infrastructure. Leading states are connecting economic development with energy system readiness by aligning large-load attraction with realistic views of capacity, interconnection timelines, and infrastructure needs. Streamlined siting and permitting processes are also critical, as delays can materially affect project viability and system costs.

States are also seeking to expand the use of demand-side resources and load flexibility to manage near-term constraints and reduce infrastructure costs, but they cannot do so effectively without close coordination with utilities and grid operators. The value of those resources will depend on whether they are targeted to the right locations and can demonstrate performance in ways that can be incorporated into planning. States that integrate policy, planning, regulation, and economic development into a cohesive strategy and communicate that strategy and associated tradeoffs clearly will be better positioned to attract investment while maintaining reliability and cost discipline.

Conclusion

Electricity demand growth is real, but demand alone is not the full story.

The next phase will be defined by delivery: how quickly the grid can add the generation, transmission, distribution upgrades, demand-side resources, and flexible load capabilities needed to serve new demand reliably and affordably.

The regions that coordinate these pieces most effectively will be better positioned to capture economic growth, manage costs, and maintain reliability.

Forecasts show where demand may grow. Delivery will determine where that growth can actually be served.

For more information, contact:

Deb Harris
Vice President, Energy & Climate Planning
Deb.Harris@icf.com

Pat Milligan
Director, Energy Markets
Pat.Milligan@icf.com

Himali Parmar
Vice President, Energy Markets
Himali.Parmar@icf.com

Justin Mackovyak
Vice President, Strategic Enablement
Justin.Mackovyak@icf.com

Shanthi Muthiah
Senior Vice President, Energy Advisory
Shanthi.Muthiah@icf.com

Maria Scheller
Vice President, Energy Markets
Maria.Scheller@icf.com

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