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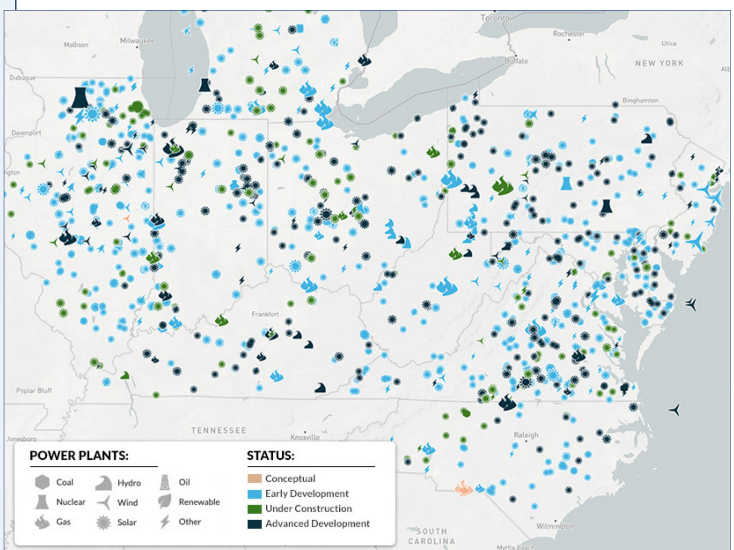
YES ENERGY

ISSN 2377-8016 : Volume 2026/Issue 1 ▪ January 6, 2026

2026: A LOOK AHEAD

Your Guide to the Issues Dominating the Regulatory Landscape

Can Restructured Markets Meet the Challenge of Data Center Demand Growth?



Yes Energy

Getting new generation developed to maintain reliability and affordability in the face of new demands driven by large loads is the key issue facing FERC and the organized markets it oversees in 2026 and beyond.

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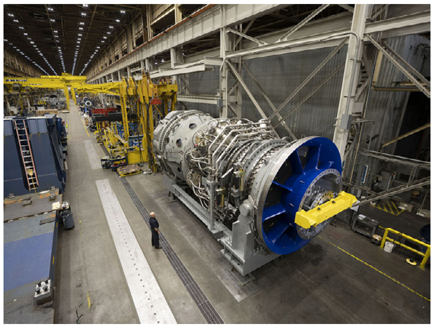
Dominion Energy

Trump Scoring Victories as he Goes Tilting at Wind Turbines (p.44)

Wind power is an important part of the U.S. power portfolio, producing as much electricity in 2024 as hydroelectric and utility-scale solar generation combined.



GE Vernova

Natural Gas Generation in Demand, and Priced Accordingly (p.38)

Soaring demand for new natural gas generation faces manufacturing backlogs and other constraints.

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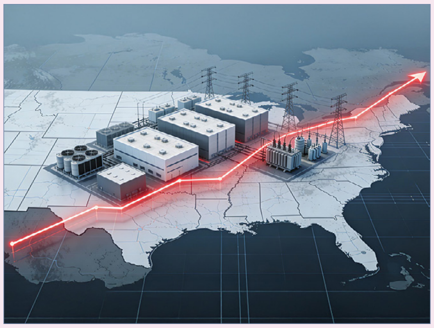

Illustrated by Perplexity

2026: The Year the Humble Electron Becomes Politicized (p.4)

Shoring up the grid from potential disturbances caused by data centers is going to be increasingly important, while the facilities' impact on resource adequacy will also continue to be a major issue facing the entire power industry.

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Editor's Note: The Only Certainty in 2026 is Continued Uncertainty

Ken Sands

If we learned anything about U.S. energy policy in 2025, it's that regulatory and legislative changes are unpredictable given the political landscape. As we enter 2026, there's little to suggest this will change.

Federal agencies under President Donald Trump's control, such as the Department of Energy, the Bureau of Ocean Energy Management and the Bureau of Land Management, are aggressively fighting wind and solar generation, while promoting continued use of coal and methane to produce electricity.

Will Congress attempt to reassert some authority? Will the courts intervene? And will the turnover of FERC commissioners result in policy shifts?

All the attention on generation is because of the expected explosion of load from AI-focused data centers. Hundreds of projects representing many billions of dollars are on the drawing boards of high-tech companies looking for the states most willing to fast-track permitting and siting.

And then there's the transmission needed to connect generation to load, and who will pay for it.

How do the RTOs plan for generation, load and transmission needs decades into the future when the short-term outlook is so uncertain? They're in need of a Goldilocks solution: The infrastructure buildout shouldn't be too big, and it must not be too small. Getting it just right is a tall order.

In this special edition of *RTO Insider*, we look at the most pressing issues in 2026 for each of the RTOs. We look at the landscape of each of the major sources of generation. And our columnists weigh in with their views on where this is all headed.

We hope you all enjoyed a break over the holidays. There's much work ahead. Buckle up.

— Ken Sands

Whither FERC?

By Steve Huntoon

Why This Matters

The unitary executive theory doesn't make any sense because it's premised on the notion that Congress can't pass a law granting a federal agency some element of independence from the whims of a president, writes Steve Huntoon.

Steve Huntoon

As Yogi Berra didn't say (at least not first): It's tough to make predictions, especially about the future.

But I'm going to stick my neck out and predict that the dozens of independent federal agencies like FERC will survive the Supreme Court's revisiting of *Humphrey's Executor v. United States*.

The conventional wisdom is that the court will invoke something called the "unitary executive theory" to reverse 90 years of precedent, and allow the president to unilaterally fire whoever he wants from any federal agency for any reason at any time.

The unitary executive theory doesn't make any sense because it's premised on the notion that Congress can't pass a law granting a federal agency some element of independence from the whims of a president. Why can't Congress do that? It's the first branch of our government with the power to pass laws. That's what it's supposed to do. And let's remember that the president can always veto a law he or she doesn't like, which then requires Congress to muster an overwhelming majority to override the veto. And let's note that the veto is a "legislative" power (it's in Article I after all), which discredits the notion that legislative and executive powers can't mix.

But somehow the idea emerged that Congress' legislative power to pass laws, subject to veto, is circumscribed by a president's executive power to override such laws because, well, he's the president.

Let's put aside all the intricacies and nuances that have inspired countless law review articles on this subject.

Instead let's surmise what the swing justices think of Donald Trump's conduct. Justices don't live in a vacuum. They see the same stuff that we do (or at least I hope so).

Prior drafts of this column listed 34 of Trump's worst Constitutional, legal, ethical and aesthetic outrages in 2025 (actually 37 when I added the latest offshore wind, Greenland and battleship-naming outrages). But having depressed myself assembling the list, I realized that I shouldn't pass it on, at least not in the holiday season. You may have your own list. And I hope the swing justices do as well.

I am guessing, and hoping, that the cumulative effect on the swing justices will be that they just can't stomach giving Trump more power. They won't take this further step toward autocracy, as happened in other countries. "Centralization of head-of-state control over the executive branch of government provides a pathway to autocracy. Indeed, unilateral presidential control of the executive branch constitutes a defining characteristic of autocracy."

But maybe this is just wishful thinking.

Speaking of wishes, I wish you and yours the best for the year ahead. ■

2026: The Year the Humble Electron Becomes Politicized

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

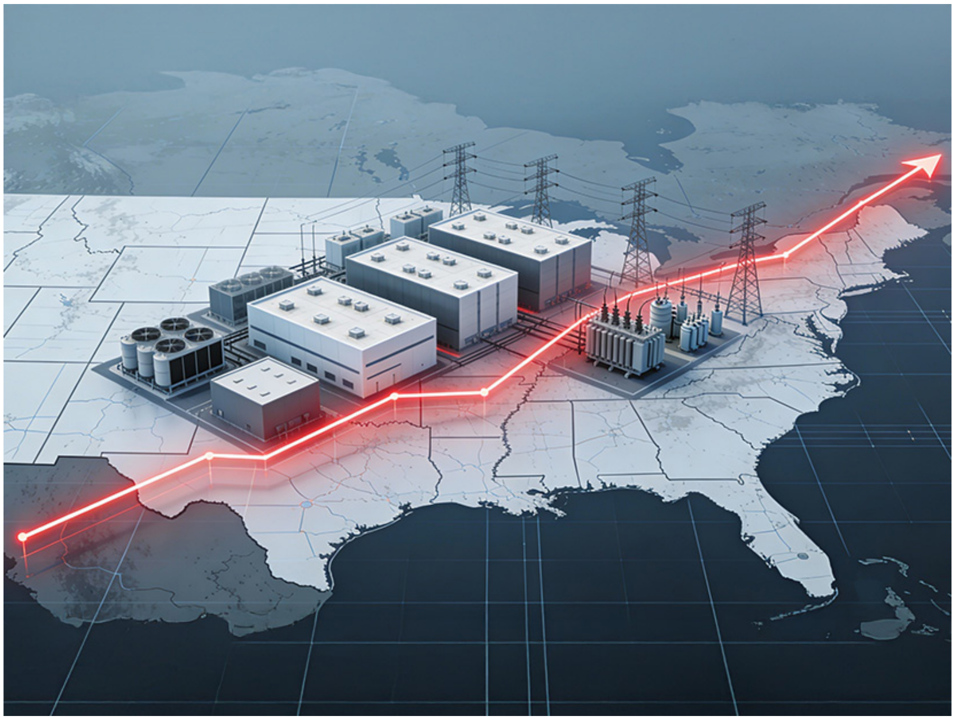
As we turn the page from 2025 to 2026, the trends of the past year are not just continuing, they are accelerating. The defining story of the coming year will be the widening chasm between electricity supply and demand, a dynamic driven by a slow-moving supply side, coupled with the explosive growth of energy-hungry data centers.

Physical bottlenecks: Access to hardware, whether for generation or transmission, is becoming a big problem. Transformers, switchgears and turbines are in short supply and increasingly expensive. Even when equipment is available and developers can put steel in the ground, the existing interconnection process is far too sluggish to meet projected demand. While some grids are working to fast-track these issues, and even employing AI to assist with the process, it's not fast enough.

Even if we could access equipment and resolve the interconnection issue, there's simply not enough existing transmission to accommodate new supply. That barrier exists largely because the permitting process is agonizingly slow — where transmission facilities traverse multiple states. The SunZia and Grain Belt Express projects are strong examples: Each took well over a decade to get approvals lined up.

Why This Matters

Between massive AI loads and the infrastructure permitting debate, the stage is set for a collision between the fast-moving culture of Silicon Valley and the regulated and risk-averse power sector, says columnist Peter Kelly-Detwiler.



Capacity prices overlaid on top of data centers sitting astride the U.S. | *Illustrated by Perplexity*

Software and applied intelligence augment the existing system's capabilities to do more, with applications such as dynamic line rating, topology optimization and power flow management. They, as well as reconductoring of existing transmission lines, can provide some relief but cannot meet the magnitude of the challenge.

These infrastructure timelines are simply incompatible with the "I-want-it-yesterday" urgency of the data center industry — the modern-day equivalent of Rumpelstiltskin that no longer spins straw into gold, but rather converts data, silicon chips and power into enormous digital wealth.

Financial and National Security: There's also a pressing national security imperative. Those countries that dominate the data also will dominate the future economy and military battlefields. The Russia-Ukraine conflict, rapidly shifting from a people-centered struggle to one driven by software, fiber optics and lethal drones, clearly demonstrates how swiftly AI is transforming modern warfare and how urgently the global AI race must be won.

The Astonishing Accelerating Pace of Change: Three short years ago, AI had a relatively minimal profile. The launch of ChatGPT 3.0 catalyzed a rapid shift in that industry, and a race to feed chips and machines with power. Here, though, the virtual world collides with the physical reality and complexity of the electric grid. That collision creates significant uncertainties because of the speed and the magnitude of the projected growth in demand.

In this new world, billions of dollars now seem trivial, AI companies make circular investments in each other, and chip technologies and AI modeling approaches constantly evolve. It's also a world in which few AI companies are demonstrating profitability. We may well look back at 2026 as the start of a golden age, or as a repeat of the dotcom bubble — leaving behind enormous, stranded assets if the promised returns fail to materialize.

The Federal vs. States' Rights Collision: In 2026, the electron will sit square in the middle of the centuries-old tug-of-war between state sovereignty and federal oversight. This is epitomized by the Department of Energy-mandated FERC rulemaking to standardize large load interconnection processes.

The related debate is contentious. By the recent comment deadline, approximately 150 comments had been filed. State entities such as the National Association of Regulatory Commissioners (NARUC) and the National Conference of State Legislatures pushed back, with NARUC commenting: "The commission should avoid any action that would circumvent or negate state decisions governing the provision of retail service." Similarly, the NCSL stated: "This new proposed rule would bring under federal jurisdiction an issue that is currently handled by the states and has been for decades. … Such actions should also not remove decision-making powers that have historically been left to the states."

FERC must publish its determination by April 2026. Given the size of the prize at stake, it's likely to be controversial and spark ongoing debate regarding states' rights.

As big as that issue is, it may be eclipsed by legislation related to permitting of new energy infrastructure. Construction of such infrastructure inevitably raises questions about states' rights, eminent domain and property rights. States have been quite successful in either delaying or terminating many infrastructure projects proposed over recent decades. That's one critical reason so little energy infrastructure has been built recently. But it's also not a sustainable model for the future, given the pressures on today's fragile grid that are further exacerbated by data loads.

When Elephants Fight, Grass Gets Trampled: With obvious shortfalls in capacity to meet new large loads, we already are seeing the impacts on other customers' wallets. The past three capacity auctions in PJM have resulted in punishingly high prices for load. In the first two auctions, the revenues associated with existing and forecast data center load were estimated to exceed $16.6 billion, representing more than half of the entire revenues paid to capacity. The second auction, for 2026/27, would have gone higher had a negotiated cap not been in place.

The most recent auction in mid-December for 2027/28 saw prices hit the cap again, clearing at $333.44/MW-day, and likely adding an additional $8 billion of data-related costs to the data center-related tab. Worse yet, when PJM ran a simulated auction absent the cap, prices catapulted to $529.80.

This burden falls squarely on other ratepayers, with capacity costs now representing well over 25% of the wholesale power bill. Absent political or regulatory intervention, the effects may get much worse, since the June 2026 auction for 2028/29 no longer is capped.

The Rise of Flexible Load: To mitigate these effects, many PJM members insist that new large loads must bring their own capacity or agree to be interrupted. They maintain this is the only way to ensure that other ratepayers are not affected. Clarity is hard to come by: A dozen proposals related to large load interconnections recently were considered by PJM stakeholders, but none were approved, leaving lack of clarity as to what to do next.

Meanwhile, a FERC ruling told PJM to develop a clear set of rules (and report back by Jan. 19, 2026) for co-located data centers siting next to generation to speed access to power, and their associated impacts on transmission.

Meanwhile, in Texas, Senate Bill 6 was signed into law in 2025, authorizing ERCOT to use the so-called "kill switch" to cut power to data centers during grid emergencies. Details as to how that will work in practice are being resolved. Just to the West, SPP has approved an expedited interconnection process of just 90 days if data loads commit to being interrupted when necessary.

2026 a Volatile Mix: With electricity bills rising, data-related loads have become a lightning rod. The coming year promises a heated political environment. Already House Democrats have floated the "Protecting Families from AI Data Center Energy Costs Act," urging FERC to examine ways to manage rising power costs associated with data centers.

Add to that President Donald Trump's Dec. 11 executive order "Ensuring a National Policy Framework for Artificial Intelligence." Between massive AI loads and the infrastructure permitting debate, the stage is set for a collision between the fast-moving culture of Silicon Valley and the regulated and risk-averse power sector. Then throw in the centuries-old tension between states and federal power just to spice up the mix. In 2026, electricity no longer will be just a commodity; it will become a political flashpoint. ■

Will Batteries Remain a Clean Energy Bright Spot in 2026?

By Dej Knuckey


Dej Knuckey

Energy storage is the great enabler of the clean energy revolution, moving electricity in time, much like transmission moves it in space. In 2026, utility-scale energy storage projects in the United States will face headwinds that could slow the pace of a technology that is fast becoming a global grid staple.

The question is whether the challenges the energy storage industry faces will outweigh the strong demand for its services. And if they do, what implications will it have for the grid?

Batteries are the Pinch Hitter of the Grid

Battery energy storage systems (BESS) provide a vital service for clean energy that is generated with a side of intermittency — solar and wind — by taking electricity generated at one time of day and storing it until it's needed. The obvious benefits of smoothing supply and limiting wasteful curtailment are just the start.

BESS can provide stability, resilience and resource adequacy services to the grid, even when wind and solar aren't involved, supporting baseload reliability. And at a time when interconnection queues are measured in years, integrating BESS can enable developers to build larger renewable projects than the interconnection point otherwise would allow.

These benefits provide real, measurable value. For example, a recent report found that solar and battery storage growth could reduce New England wholesale energy costs by more than two-thirds of a billion dollars a year by 2030. (See *Report Shows Cost Savings from New Solar, Storage in New England*.)

Emerging Stability After a Year of Uncertainty

2025 was a doozy: on-again-off-again tariffs, supply chains redirected to avoid foreign entities of concern (FEOC) restrictions, political standoffs over critical minerals, massive renewables projects suspended on a whim and U.S. battery manufacturing rushing to fill the gap. Yet despite everything, growth in the onshore manufacturing base and deployment of utility-scale BESS grew throughout the year.

The energy storage market, which law firm Troutman Pepper Locke called *"bruised but buoyant,"* largely was spared in President Donald Trump's tax bill (One Big Beautiful Bill Act, or OBBBA) because of batteries' role in providing baseload power. "However, the battery storage industry faces significant constraints from the OBBBA, most notably, the FEOC rules. These restrictions — which vary depending on the tax credit and tax year in question — prevent entities linked to adversarial nations, particularly China, from accessing, directly or indirectly, the benefits of U.S. energy tax incentives," its *report* said.

Wood Mackenzie and the American Clean Power Association *attributed the year's strength* to rising demand and the need for grid reliability. "These installations deliver the flexible, reliable grid support America needs today, boosting reliability and keeping power bills in check," said John Hensley, ACP senior vice president of markets and policy analysis.

So, what lies ahead for our versatile friends in 2026?

Trend 1: Market Solid as Global Supply Chain Concerns Fade

2026 should see a solid, but not stellar, market.

The good news: The volatility of early 2025 has settled. Early 2025 saw so much regulatory whiplash that analysts resorted to issuing high and low predictions. One thing the market hates more than new regulations is uncertainty, and the return to single-scenario forecasts shows a return to confidence.

Analysts are mixed about 2026. The most optimistic expect only a modest rise, while others expect a modest pullback. There's no concern about demand; supply constraints and interconnection queues will dictate how the year will unfold.

The often-conservative *EIA estimates* that U.S. utility-scale BESS will grow from 45.6 GW at the end of 2025 to 65.6 GW at the end of 2026, more than doubling total installed capacity since the end of 2024. The 20 GW addition is only a slight increase from 2025's 18.6 GW capacity addition, according to its December 2025 Short-Term Energy Outlook.

> **Why This Matters**
>
> At a time when interconnection queues are measured in years, integrating batteries can enable developers to build larger renewable projects than the interconnection point otherwise would allow.

On the other end of predictions, *Wood Mackenzie* forecasts that supply chain issues in the near term will drive an 11% contraction in the U.S. utility-scale storage market in 2026, followed by an 8% decline in 2027. Despite the expected pullback in 2026, the medium-term outlook is rosier than in early 2025. "Notably, the utility-scale five-year forecast has increased 15%" compared to pre-OBBBA projections.

Materials and manufacturing constraints will continue to throttle the market.

The U.S. may have some of the not-so-rare-earth materials needed to build batteries, but even when they can be mined, there's often no way in the U.S. to refine them to battery-grade purity. It hasn't been economically viable in the past, and building out those capabilities won't happen overnight.

Similarly, building a battery factory requires a significant amount of time, as well as massive amounts of capital, which is flighty in a time of *political intermittency*. Battery manufacturing had a head start as factories already were under construction. In 2026, we'll see several of those plants come online and others expand production, increasing the supply of cells and batteries made in the U.S. LG Energy Solution's plant in Arizona should come online, and its Michigan plant should increase production. SK On's

Georgia plant should begin production in the second half of the year after pivoting from automotive to stationary energy storage.

Trend 2: Energy Storage Everywhere

In the past five years, BESS has begun to be decoupled from renewables. Its versatility means it's solving problems throughout the increasingly overburdened grid. While many solar farms have BESS on site, 2026 will see an increase in the use of BESS to provide resilience, stability and reliability. A couple of examples: In Oregon, *backup systems sited at substations* provide resilience, while in California, a *whole-town backup* system with BESS and hydrogen fuel cells has been installed in Calistoga to power the town during public safety power shutoffs on high-fire risk days.

While most of the new utility-scale energy storage capacity will be in California and Texas, the need for resilience knows no borders. With the rise in extreme weather events that can knock the grid offline, there's increased demand for grid-tied microgrids that support critical infrastructure such as hospitals.

Energy Storage and the Growth of AI

The rise in AI data centers has upended forecasts from just a few years ago and is driving creative ways to meet demand without yearslong delays. This need to move quickly in an industry slowed by regulation and the need for so many rounds of community engagement is bringing forth creative ways to slip energy projects in with AI data centers that are being fast-tracked.

One potential solution is what *RMI calls "Power Couples,"* which use batteries so AI data centers can be built out without affecting local electricity reliability and cost. RMI defines a Power Couple as the "pairing of a large electricity consumer with new-build solar, wind and battery resources sized to meet the on-site load, all located near an existing generator with an approved interconnection."

This would mean the customer who benefits could bear the costs and take advantage of fast-track approval for connecting the new generation resources to the grid, and strict physical safeguards would ensure that the new load cannot affect grid reliability.

| Shutterstock

Trend 3: Community Resistance will Go Pro

While most other headwinds will die down in the coming year, *community resistance* will be an increasingly significant problem in 2026. Concern about BESS' safety has grown following the high-profile January 2025 fire at Moss Landing, Calif., at the time the world's largest lithium-ion battery system. It raised awareness of the potential risks of having BESS sited nearby, and armed community opposition groups around the country with a vivid example.

When they occur (which is not that often), lithium battery fires are difficult to extinguish and can produce toxic substances such as hydrogen fluoride, phosphorus pentafluoride and phosphoryl fluoride. Community groups can draw on a growing body of evidence that the risk persists beyond the initial fire, such as the *recent report* on toxic residue in the Elkhorn Slough wetland near Moss Landing.

Some lithium battery chemistries are safer than others; for example, lithium iron phosphate (LFP) batteries are less likely to have thermal runaway than lithium nickel manganese cobalt (NMC), the battery chemistry used at Moss Landing. For that reason, LFP will take an ever-larger share of the market — estimates put LPF at about 80% of the utility-scale market in the U.S. But once a developer is educating the public about the nuances of battery chemistries, it's already losing the public relations battle.

NIMBY, Meet BESS

The forces that don't want renewables to flourish (I'm looking at you, *oil and gas*) have taken a leaf from the misinformation campaigns used by the tobacco industry (if you haven't seen "*Thank You for Smoking*," it's a must watch). So far, solar and wind farms have been their primary targets, but if they haven't already, these "astroturf" campaigns will set their sights on BESS.

Astroturf is the tongue-in-cheek term for non-local organizations that are trying their darndest to look like grassroots efforts. Of course, some of the opposition is grassroots, but astroturf groups supercharge them, supplying ready-to-execute playbooks that savvy political insiders have tested and refined.

How to tell if they're behind community opposition campaigns? Look for overly wholesome names (Patriotic Americans for Energy Freedom, anyone?) and search their materials for language that been used to stonewall projects throughout the country. For example, *NIMBY groups* protesting solar farms consistently described them as "industrial solar," a negative term that proved effective in early anti-solar fights.

Astroturf is not the only resistance strategy. Other opposition will grow through under-funded *local media, which spreads misinformation* on a pay-to-play basis, and *local codes or guidelines* written to limit certain development.

Are they succeeding? In part. In the past year, significant projects were shelved due to community pressure, including a *650-MW project on Staten Island* that was canceled. Others, like the *320-MW Seguro project in San Diego*, are mired in hearings. Some of these projects are large enough to materially affect regional storage deployment, and all will cause developers to think twice about planning projects anywhere near communities.

Batteries Withstanding Market Battering

Taking all the positives and negatives together, 2026 should be a solid, though not soaring, year. Batteries will continue to be the bright spot in the clean energy landscape in the United States, and their ability to support the grid and delay costly transmission projects makes them critical.

To help the market grow, developers will need to get ahead of community resistance or focus on projects away from residential areas or rural idylls rather than risk being mired in endless permit fights. Groups like American Clean Power need to continue educating and lobbying critical audiences to ensure BESS projects aren't unduly harmed.

And the industry needs to differentiate types of lithium-ion batteries to end-run community and fire service objections. LFP, despite its lower energy density, will continue to take an ever-larger share of the market, at least until new chemistry batteries are widely available.

Project developers and the grid their projects connect to operate in time frames well beyond any single administration. BESS projects are fortunate to have avoided the Trump administration's crosshairs, which harmed other clean energy sectors. My hope for 2026 is that it will continue to work its magic, quietly installing reliability and avoiding controversy. ■

— Power Play columnist Dej Knuckey is a climate and energy writer with decades of industry experience.

Why 2026 will be the Year of Flexibility

It Makes Renewables Dispatchable, Turns Buildings into Grid Assets and Cuts Electric Bills

By K Kaufmann

K Kaufmann

Why This Matters

Clean energy will continue to grow, but the more significant paradigm shift will be toward policies that promote flexible technologies, ensure they are valued and compensated appropriately and accelerate permitting, says columnist K Kaufmann.

The first time I heard an energy industry official mention the word "flexibility" was back in the early 2010s, when I was a fledgling energy reporter at *The Desert Sun* in Palm Springs, covering the permitting and construction of an 800-MW natural gas power plant to be located north of the city. The *Sentinel plant* and its eight, 90-foot-tall emission stacks were needed for system flexibility, a representative from CAISO told me.

As more and more variable renewables came online — like the hundreds of wind turbines also located north of Palm Springs and the first utility-scale solar projects on federal land east of the Coachella Valley — flexible power that could come online quickly was critical, the official told me. And back then, fast and flexible meant natural gas.

Sentinel was a peaker — ideally used only to fill gaps in power supply at times of high demand — and was licensed to operate only one-third of the time. It could fire up in about 10 minutes, and according to an environmental impact report that I read in detail, could put up to one million tons of carbon dioxide per year into the region's already polluted air.

(Despite its status as a major resort area — and home to one of the country's largest music festivals — the Coachella Valley has notoriously poor air quality, due in part to the hundreds of diesel-powered 18-wheelers rolling through it daily on the Interstate 10 highway.)

CAISO ran its first demonstration projects using energy storage for system flexibility between 2014 and 2016 — after I left Palm Springs — but the results were impressive. I was in D.C. at the Smart Electric Power Alliance by then and remember another conversation with a contact at CAISO, who told me the storage was faster and more flexible than a natural gas peaker.

Ten years on, California has 17 GW of energy storage online, allowing the state to ride out summer heat waves — just one sign that flexibility has gone from marginal to mainstream. It also is a core attribute of the various scenarios and solutions being discussed to meet the snowballing estimates of U.S. electric power demand that drove headlines in the industry and mainstream media in 2025.

2026 is going to be all about how to further integrate flexibility as part of a clean, reliable and affordable electric power system. The technology is available, with prices going down and advanced capabilities expanding at speed and scale, powered by artificial intelligence. The lag, as ever, is on the policy and regulatory side.

The questions will be about what kind of new or different market mechanisms and regulatory guidelines will be needed to ensure the U.S. power system can take full advantage of all the different value and revenue streams flexibility can offer.

Specifically, regulators have yet to figure out how to fully integrate and compensate distributed technologies, like storage, which do not fit into traditional categories of supply and demand — generation and load, charge and discharge — and how these different technologies are rated on the grid.

But the typically glacial pace of regulation — with endless pilot projects and decisions often years in the making — is no longer tenable. Demand growth, rising electric bills and the need for system reliability and resilience are converging to accelerate the pace of change, with big tech hyperscalers — companies like Google building gigawatt-scale data centers — pushing all the various envelopes involved.

What is ahead will be exciting, uncomfortable and unavoidable for all stakeholders, including President Donald Trump and his supporters, who, despite all evidence to the contrary, are stubbornly clinging to fossil fuels as the primary solution for all the challenges of demand growth.

The Flex Front 2025

Any discussion of grid flexibility probably should start with a working definition. In grossly oversimplified terms, we know that our electric power system is overbuilt to handle periods of high demand that may occur only a handful of times each year, which means it often is grossly underused. That excess capacity can be optimized with grid-enhancing technologies — like advanced conductors and dynamic line ratings — which in turn can allow for the flexible integration of different forms of carbon-free generation and storage.

Further, electric power can be "flexed" at all levels of the system, from residential, commercial and utility-scale to distribution and transmission.

That flexibility in and of itself framed new and innovative views of the grid in 2025, beginning with a Duke University *study*, released in February, suggesting that if data centers were willing to curtail their electric use even .25% of the time, it would open up space on the grid for 76 GW of new generation. A curtailment rate of 1% could mean enough headroom to add 126 GW of new power.

The study has been widely cited, and Tyler H. Norris, its lead author, quickly became a much-sought-after speaker at industry conferences and webinars. In November, Google hired Norris to lead its market innovation and advanced energy initiatives.

Other key developments on the flex front included:

- The July 29 virtual power plant *demon-*

stration in California: More than 100,000 residential batteries simultaneously discharged for two hours, from 7 to 9 p.m., pumping out 539 MW of electricity, or the equivalent of a mid-sized power plant. An *analysis* of the demonstration by The Brattle Group concluded that the aggregation of behind-the-meter solar and storage "can deliver reliable, utility-scale capacity at a significantly lower cost than traditional solutions."

- Energy Secretary Chris Wright's Oct. 23 *directive* to FERC: Wright proposed new rules for the interconnection of "large loads" — that is, data centers — which would allow expedited approvals for co-location of centers and generation if power at such facilities could be curtailed or dispatched by a grid operator. FERC received more than 200 comments on Wright's proposed rules, with hyperscalers in particular opposing any rule that linked expedited interconnection to curtailment controlled by grid operators or utilities.
- The Electric Power Research Institute's *DCFlex* initiative: Significantly, EPRI launched this new program in 2024, with the goal of developing data centers as flexible grid assets. A heavy-hitting list of project collaborators includes Google, Meta, Microsoft, Nvidia and Schneider Electric, along with major utilities, RTOs and ISOs. An interactive *map* on the DCFlex website shows that utilities in 41 states already have some kind of flexible load or demand management programs.

Clearly, everyone — even Chris Wright — knows that change is coming; flexibility will be a critical must-have, and those who are not ready or willing to innovate and invest will be left behind.

Above Politics

The physics, economics and politics of the next few years are well known. Estimates of the amount of new power the United States will need by 2030 increase with almost every new report. Back in February, the Duke University study estimated that data centers alone would drive 65 GW of new demand by 2029.

An *ICF report* from May called for 80 GW of new power to come online per year for the next 20 years, while in November, Grid Strategies *upgraded* an earlier estimate of 128 GW needed by 2030 to 166 GW.

The Sentinel natural gas peaker plant north of Palm Springs | *Diamond Generating LLC*

The turbines that will power new natural gas plants could take years to deliver due to material and labor shortages and leave consumers vulnerable to the turbulence of natural gas prices. Renewables are cheaper and faster to build — and according to *interconnection.fyi*, still make up about 88% of projects sitting in interconnection queues nationwide — but face a virtual obstacle course as the Trump administration, RTOs and some utilities prioritize natural gas and nuclear.

Natural gas and renewables also will require new transmission and streamlined, accelerated permitting, all of which, including new data centers, are likely to face local opposition.

And electric bills are going nowhere but up — period. The ICF report estimates that residential rates could rise 15 to 40% by 2030, depending on the region.

Flexibility redefines everything and, again, is available immediately with existing technologies, which will get cheaper and smarter with speed and scale. This is why it will be essential for system evolution at all levels in 2026.

Flexibility turns grid-edge renewables from variable or intermittent to flexible and dispatchable resources that can shave peak demand, as seen in California's VPP demonstration. Homes, businesses and data centers all can serve as flexible grid assets, which can help cut electric bills and drive behavioral change.

Consumers increasingly will see the value of adopting technologies that combine energy efficiency with flexibility — like solar and storage — so they can participate in even more sophisticated demand management programs.

In addition, upgrades that make existing transmission and distribution systems more flexible could allow for more distributed renewables, while triggering less local NIMBYism and reducing the need for new fossil-fueled generation.

In other words, flexibility is a no-brainer. It is above politics, and it just makes sense.

Fail and Scale Fast

President Trump notwithstanding, clean energy will continue to grow — though at a slower rate — in 2026 because it is faster, cheaper, cleaner and more flexible than fossil fuels. But the more significant paradigm shift this year will be toward policies, again at all levels, that promote the adoption of flexible technologies, ensure they are valued and compensated appropriately and accelerate permitting.

While Trump and some major players in the industry frame the current crunch in demand growth as an "energy emergency," it actually is a long overdue and extremely cool opportunity for the electric power sector to reinvent itself. It has been dragging its feet on a 21st-century makeover, while its customers increasingly move at the blistering speed of AI.

High-tech hyperscalers are setting the pace. They want power, speed and flexibility for their data centers. They have the technology, the experts and the money to invest in system change; they know how to fail and scale fast; and they do not like waiting for regulators or utilities unless they absolutely must.

Interconnection policies have become the front line of change, where expedited approvals for projects turn on their ability and willingness to flex their power. Texas pioneered this kind of "conditional interconnection," now codified via *SB6*, signed into law in June. California followed suit in August with its *Limited Generation Profiles* policy, which limits the amount of power distributed projects can export to the grid at times of system stress.

What is particularly exciting here is the implicit acceptance of flexibility as a central attribute of the grid and how that in and of itself redefines reliability and resilience.

PJM will provide the acid test of this approach as it works to comply with FERC's recent *order* requiring an overhaul of the RTO's interconnection policies for new generation co-located with data centers. In particular, the order requires PJM to adopt rules and the associated tariffs for co-located generation that can self-curtail or flex its demand on an interim or regular basis. (See *FERC Directs PJM to Issue Rules for Co-locating Generation and Load*.)

Any final rules from FERC promoting flexible interconnection should send a signal to other grid operators, states and utilities. Wright's directive called for the federal regulators to complete work on his proposed rules by April, which would be warp speed for the commission, especially given the many concerns raised by stakeholders.

Demand management also is going to move fast. With Tyler Norris on board, we can expect to see new initiatives in this area from Google, which has *signed* flexible demand agreements with the Tennessee Valley Authority and Indiana Michigan Power. Meanwhile, Amazon is promoting *grid-enhancing technologies* as a way to get more renewables online.

Building on California's demonstration, 2026 will see a ramp in VPPs. A recent *article* in *Energy Storage News* details three new VPPs being launched by a range of developers and utilities in California, as well as in Texas, Washington, Arizona and the Tennessee Valley. One example is a new partnership between software developer Leap and independent power producer Enel North America that aims to connect commercial distributed resources to utility demand management programs.

Why is any of this important? As flexibility becomes the new normal, it makes us think about electric power differently. It redefines our relationship to how we produce it, how we use it and what we can do with it. It makes us aware that we as consumers have an active role to play here, and that we can do more than complain about rising electric bills and then pay them.

Let us also remember that when we talk about flexibility and renewables, we are talking about climate change and reducing greenhouse gas emissions, whether we use the actual words. We have shifted from an environmental to a practical, business case for climate action, which is equally if not more effective.

Coming full circle, in 2024, the Sentinel plant was approved for a 17.18-MW, 34.36-MWh battery storage system to provide black start capability, so the plant can restart itself even if it goes offline.

When peakers need extra flexibility, we are way past the point of no return; 2026 is going to be a good year. ■

Can Restructured Markets Meet the Challenge of Data Center Demand Growth?

By James Downing

Why This Matters

Getting new generation developed to maintain reliability and affordability in the face of new demands driven by large loads is the key issue facing FERC and the organized markets it oversees in 2026 and beyond.

The biggest issue facing FERC and the organized power markets it oversees is how they can meet rising demand reliably and affordably.

The Advance Notice of Proposed Rulemaking on large loads from Energy Secretary Chris Wright and the co-location proceeding in PJM are both undergirded by the need to build new power plants. (See *FERC Directs PJM to Issue Rules for Co-locating Generation and Load*.)

"As I've been saying now for five years, PJM is heading for a reliability crisis, and now we're there," former FERC Chair Mark Christie said in an interview. "It's no longer over the horizon. It's right on the street with us, and the latest capacity auction results just drive home how bad the crisis is, when they fall short 6 GW of meeting the reliability requirement." (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

The primary driver for that crisis is the demand from new data centers, which has so far not been met with new generation to match it, he added.

"Really the problem is financing more than anything else," Christie said. "We're not getting large baseload generation built. We're not getting combined cycle gas, which is the baseload generator of choice."

Coal plants are not feasible at this point, and nuclear is not going to be ready at scale in time to meet the demand from data centers plugging into the grid soon, Christie said. Wind and solar, which dominate the queue, add much needed electricity to the grid, but they cannot be counted on to serve demand from data centers that want 99.999% reliable power, he said.

Christie's home state of Virginia is a major contributor to the issue because it is home to the largest data center market in the world, Data Center Alley, and has contributed to the demand growth recently by plugging in new facilities that are ultimately served by imports from elsewhere in PJM.

"The Dominion zone was a big contributor to the deficit," he added. "And we're going to see whether the new governor and the new legislature are going to take action to try to get large baseload generation built."

The supplies being added to the grid are either wind and solar or combustion turbines, and Christie is skeptical that the market on its own can add new baseload plants.

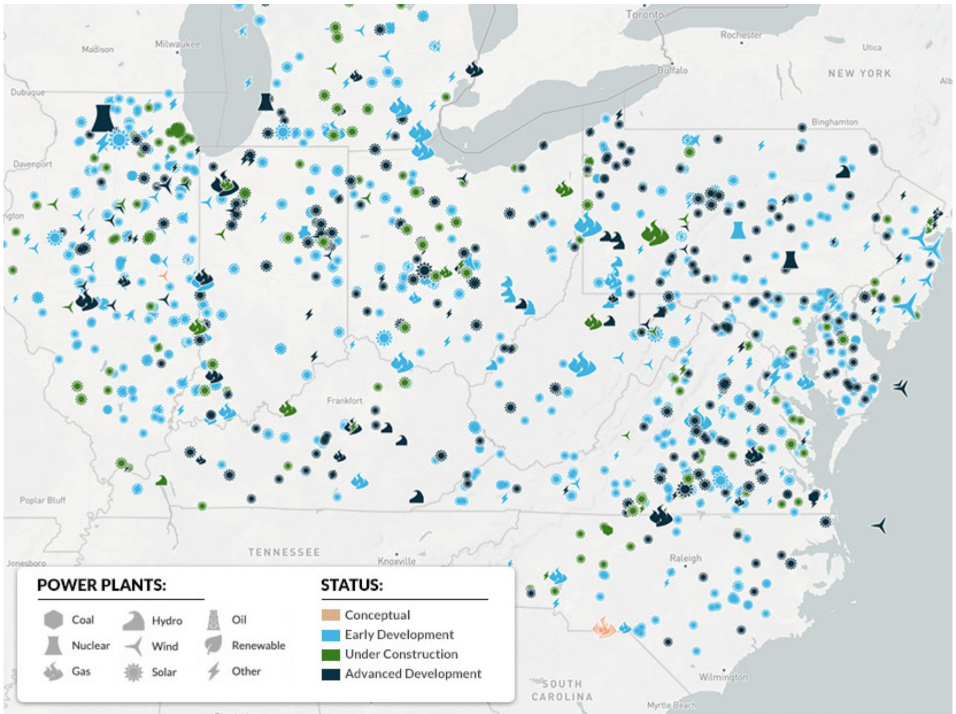
"I don't know how high prices have to go to get large baseload generation built, but politically, you're already getting a huge backlash because we've hit three all-time highs in the capacity market," Christie said. "And we're not getting large baseload generation announced."

Virginia is one of the vertically integrated states in PJM, which means its political establishment needs to support the construction of new baseload, Christie argued.

"When I was on the Virginia commission, we approved four combined cycle natural gas generation units for Dominion, and every one of them got built," Christie said. "Every one of them was ratebased, but the political leadership was supportive."

PJM sits on top of huge supplies of natural gas in the Marcellus and Utica shale fields, which could power a new wave of combined cycle units.

"In the deregulated states, where they do not allow utilities to own generation, the question becomes: Who is going to build the large new combined cycle gas?" Christie said. "Are the [independent power producers] going to build it? We haven't seen announcements of that."



Planned new generation in PJM | *Yes Energy*

When states restructured their industries a quarter-century ago, PJM had excess supply, and the generators in those states were forced to sink or swim in the market, Christie recalled. Many sank, and it brought the reserve margins down for demand growth to return in a way no one expected.

"Now we're in a perfect storm that, frankly, at the beginning of capacity market 20 years ago, nobody saw," Christie said. "Nobody saw the explosion of demand coming from data centers 20 years ago."

The capacity market was put in place at a time of wide reserve margins and slow, steady load growth. Ultimately, Christie thinks the states will have to address the issue on both sides of the supply and demand equation.

"The answer is really at the state level, not FERC," Christie said. "The states have to deal with the demand side, with how they interconnect these large new data centers, and the states have got to deal with the supply side and getting generation built."

Will the Market Respond?

Electric Power Supply Association CEO Todd Snitchler said the market will respond because PJM has now had three capacity auctions in the past year that have cleared at high prices.

"We've seen almost 12,000 MW of new generation that's expected to be added to the PJM grid between now and roughly 2030," he said.

EPSA and a fellow IPP trade group, the PJM Power Providers, created a *chart* showing all the projects, including uprates and new builds, that have been committed to serve load in the market. They argued that market participants should continue responding to the higher market prices seen in the last auctions, even though they have been muted by a cap that the RTO agreed to after a complaint from Pennsylvania Gov. Josh Shaprio (D). (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

"I think the compressed timeline of the auction has made it appear that the market is slower to respond," Snitchler said. "But you know, you don't drop a $2.5 [billion] or $3 billion investment in six months, or even maybe 12 months. And so, I think you're going to see people who have had some time to digest the auction results lead to outcomes that are going to include that new generation that everyone wants to see."

Before the July 2024 auction, the previous three cleared at low prices that were effectively signaling generators to retire just before the issue of meeting demands from new large loads like data centers started to become a reality, Snitchler said.

"As you see real load growth for the first time, really in probably 30 years, it's triggering a response, and that response takes a little time to develop," Snitchler said. "You're already starting to see where there is incremental investment and new investment being made in PJM, but also in other parts of the country."

The issue of rapidly rising demand leading to narrowing reserve margins is not unique to restructured markets, with vertically integrated states in MISO and SPP facing the same issues, he noted.

"It's really a systemic issue that we're all trying to address and resolve because everybody wants to make sure that we ensure, first and foremost, a reliable system that is also cost-effective and affordable," Snitchler said. "I mean, if those two tenets aren't met, then the rest of this is academic. We have to be sure that we're

The Paradise Combined Cycle Plant in Drakesboro, Ky. | *TVA* meeting those two objectives."

The load growth the industry is facing is different from that of the past, which was driven by economic and population growth. The new large loads are clustering in specific submarkets like Arizona, central Ohio and Loudoun County, Va.

Data centers might have plans to ultimately consume the same amount of power as a major city, but generally they do not immediately plug into the grid seeking to consume a gigawatt.

"There's a construction ramp where they start from zero, and then you have that first tranche where you need to power it up," Snitchler said. "Then they add the next phase until they're finally complete."

That gives the industry some time to respond to the load forecasts, which Snitchler argued are overstating future demand. While the power sector has limited supply chains for components like combustion turbines, the tech industry has a limited capacity to build the advanced chips needed for artificial intelligence-related data centers springing up around the world.

"If you look at the number of chips that are available from Nvidia and the fact that they're sold out for the next couple of years, and there's only 60 GW of new energy demand from those chips globally, [and] if you look at what is being projected in PJM and Texas, it would require every chip that Nvidia is going to sell for the next two years and more, and that's not how that's going to work."

Utilities have also issued optimistic load forecasts that reflect plans for data centers that are not going to be built, Snitchler argued. When AEP Ohio put in place a new tariff for large load customers, it saw a pipeline of 30 GW of data centers cut down to 13 GW, and it's not clear if all those will come to fruition, he said.

"They're clearly an effective advocacy tool if you want to secure the ability to ratebase new generation, because 'nobody's moving as fast as a utility could.' … I've never heard anyone say [that], but that's the story that's being told," Snitchler said. "Then you need to have as big a number on your load forecast as possible, because that means you're the solution to the problem that you're creating."

Multiple utilities have pushed for restructured states in PJM to change their laws and allow them to ratebase new generation for the first time in 30 years, which is an idea that EPSA is opposed to, arguing it would spoil the markets its members rely on.

"I understand they have a target earnings goal that they have set for Wall Street," Snitchler said. "But that doesn't mean that we should reverse 30 years of policy to help them achieve it when there are more cost-effective and more efficient ways to do that, and by putting the risk where it's been for the last 30 years on shareholders and investors of competitive power suppliers."

The Slippery Slope of Re-regulation

Ultimately if states change the laws and guarantee rates of return for new utility-owned generation, that would cut into the revenues of market generation owned by IPPs who would eventually ask for their own guaranteed rates — unwinding markets altogether, PJM Independent Market Monitor Joe Bowring said in an interview.

"If PPL builds power plants and puts them in rate base, then all customers are paying for them," Bowring said. "There's nothing stopping PPL from directly working out a bilateral agreement with the data center and building a power plant for them. But that's not what they're asking to do. They're asking to put in rate base and charge everybody for it, and that's just a way of making everyone else bear the costs and risks of the data center load."

PJM's markets have been slow to add generation in part because of overhanging issues from the interconnection queue and unstable market design in the capacity market, Bowring said.

"The developers who were caught up in all those delays had delayed getting some of their basic milestones," Bowring said. "They're now trying to catch up, but they're behind, and that's part of the reason we haven't seen a lot of new additions."

On top of the lingering issues from the queue, the capacity market has seen its rules change often, and Bowring is also skeptical of how the RTO has implemented effective load-carrying capability ratings for power plants.

"If data centers want to come online quickly — which is fine, we want them to come online quickly — they should figure out how to bring their own generation," Bowring said. "That doesn't mean you're turning data centers into power plant operators. You sign a bilateral contract with a developer; they build the power plant. They manage all that for you, but you have power, and that's the quickest way to get things going, because the data centers have a huge incentive to get power quickly."

Some of the hyper-scalers in the data center world can build their own power plants. Google parent Alphabet *announced* Dec. 22 that it was buying Intersect, which develops power plants for new large loads. But not every data center developer is among the largest companies in the world by market capitalization.

"The market is going to take a little while to react, and I'm hoping that in a few years that will restore equilibrium," Bowring said. "But at the moment, as you know, we're something like 6,600 MW short."

While meeting new load has always been a key part of the business, the scale of the new demands from data centers is unprecedented.

"We're talking 30[,000] to 60,000 MW of demand," Bowring said. "That is absolutely unprecedented," and it's amid "a time when PJM was getting tighter for other reasons. That confluence is, I think, absolutely unique. I mean, PJM has been long for almost forever."

The last time the PJM region faced a major shortage was decades before it was an RTO, and the power pool was dealing with the aftereffects of the accident at Three Mile Island in 1979, he added.

The issues data centers present to the grid are unique, and they need to be handled differently than load growth was in the past, Bowring said.

"The whole notion of just plugging in is naive, almost willfully naive, in some cases," Bowring said. "I understand why the data centers imagined a few years ago [that] they could just plug into the grid and everything would be fine, but everyone knew at least a couple years ago that that was not going to work longer-term; that it was simply overwhelming the grid. So, it has to be dealt with in special and targeted ways." ■

EDAM Implementation to Remain CAISO's Focus in 2026

ISO Continues to Integrate Batteries at Rapid Pace

By David Krause

The Extended Day-Ahead Market took center stage at CAISO in 2025 as the ISO tabled other long-term initiatives to ensure the market's timely launch in May 2026 with PacifiCorp as its first participant.

And EDAM preparations will continue to be the primary focus for the ISO and its stakeholders in 2026.

According to a December *report* from CAISO CEO Elliot Mainzer, 2025 saw thousands of stakeholders from California and throughout the West tune in to EDAM implementation workshops that enlightened and sometimes perplexed stakeholders, with the ISO trying to quickly address new critical problems to keep EDAM's schedule intact.

The year started with a bang: In February, Powerex — which has committed to joining SPP's competing day-ahead market Markets+ — published a *paper* contending that EDAM contained a "design flaw" that could result in $1 billion in unjustifiable charges for non-CAISO participants.

The paper said EDAM's treatment of firm transmission rights and congestion would leave the market's non-CAISO participants exposed to charges for constraints occurring outside their systems while not providing them adequate ability to recover or hedge against those costs. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

About a month later, CAISO began an "expedited" initiative to decide how to allocate congestion revenues when a transmission constraint in one EDAM balancing authority area causes congestion in a neighboring BAA. (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

In late summer, FERC approved CAISO's new EDAM congestion revenue allocation design. The approved design is a short-term solution, and the ISO said it would propose a long-term design within the next two years. (See *CAISO's EDAM Scores Simultaneous Wins at FERC*.)

What's Next

After years in the making, CAISO's Extended Day-Ahead Market will open in less than five months, with market simulations currently ongoing and PacifiCorp preparing its system to join in May.

Top EDAM Challenges

RTO Insider asked CAISO and a few of its stakeholders their views on EDAM's top challenges in 2026.

CAISO Vice President of External Affairs Stacey Crowley said the ISO worked with vendors to deliver timely functionality for market simulation, supported participating entities in developing tariffs through the FERC process, and established a transitional congestion revenue allocation design informed by stakeholder input — all critical steps to enable EDAM launch.

PacifiCorp, which will join EDAM in May as the first participant, said it faced several key challenges while preparing for EDAM's 2026 launch.

"Building and testing interconnected IT systems for PacifiCorp and CAISO required extensive coordination and design adjustments that had to be integrated into the development plans of both organizations," PacifiCorp spokesperson Omar Granados told *RTO Insider*. "Additionally, managing communication and testing across numerous transmission customers and 14 neighboring utilities added significant logistical challenges."

EDAM Priorities in 2026

The coming months in 2026 will see heightened activities around EDAM implementation, with stakeholders anticipating several challenges to ensure the market opens as planned in May.

PacifiCorp remains confident in the EDAM go-live timeline, but it must resolve issues that have never been encountered before, Granados said.

For example, starting in February, PacifiCorp and CAISO will begin parallel operations for their respective market systems, staff and support processes. While the ongoing market simulations have suggested that the utility is ready for EDAM, parallel testing will "likely reveal adjustments needed before launch," the spokesperson said.

To address this concern, PacifiCorp is working closely with software partners and has established an internal issue-resolution team to quickly identify and resolve problems, Granados said. After starting in the market, further refinements and process optimizations are expected, he said.

CAISO's Department of Market Monitoring (DMM) will be "closely watching and reporting on" critical areas as EDAM is implemented, DMM Executive Director Eric Hildebrandt said. One area is market efficiency and performance, such as pricing and volumes of self-scheduling versus supply/demand that is bid into and clears EDAM. DMM will watch also how EDAM affects the broader real-time Western Energy Imbalance Market.

DMM will monitor congestion within EDAM, specifically how much transmission is available in the day-ahead market for transfers between BAAs; the amount of "unscheduled flows" and congestion revenues created by schedules in one BAA on other BAAs; and how these congestion costs and revenues are allocated among BAAs, Hildebrandt said.

Two other focuses for EDAM: the day-ahead resource sufficiency requirement and evaluation, and the day-ahead imbalance reserve product, including the impact it has on EDAM prices, he said.

As for CAISO, Crowley said the ISO will work with vendors to test systems and procedures, and to ensure market participants have the training and practices needed to fully engage at launch.

Working Across Agency Lines

RTO Insider asked CAISO how it plans to work with the California Energy Commission and the California Public Utilities Commission as EDAM launches.

Crowley noted that EDAM is regulated under FERC, but "we have worked collaboratively with California agencies such as the CEC and CPUC — as well as regulators across the West — to ensure they are informed and able to provide input into the market design."

"There is an important role for state regulators through the [Western Energy Markets] Body of State Regulators and the public stakeholder process," she said. "While state agencies do not have direct oversight of EDAM, they have also been actively engaged in the development of legislation like Assembly Bill 825, which will establish an independent governance board, committee of state regulators and other public processes similar to what occurs at … CAISO now."

DMM will publish quarterly, annual and other special reports on the performance of CAISO markets, with state regulators and policymakers being a primary audience for those documents and the recommendations they contain.

"We do outreach to key regulatory agencies in all the EDAM/WEIM states in order to highlight our reports and recommendations, answer questions and get any input state agencies have on what types of analysis and reporting they would find most useful," Hildebrandt said.

While DMM's recommendations often play a role in shaping market design, "we do not have any role in the actual implementation," Hildebrandt added. Instead, the Monitor "will be focusing on quickly identifying and helping address any problems or unexpected issues that arise" with EDAM implementation, he said.

Batteries Provide Sneaky Reliability, Kinks to Work Out

While EDAM implementation demanded much of the ISO's and stakeholders' attention in 2025, CAISO weathered yet another year without needing to issue a flex alert or call for rolling blackouts. CAISO leaders repeated highlighted the addition of massive volumes of battery storage resources as a critical contributor to grid reliability.

By April 2025, more than 12,000 MW of battery storage capacity was online in the ISO — up from about 500 MW in 2020. An additional 15,000 MW of storage resources are expected by 2028, accounting for the majority of the 20,000 MW of new resources expected in that time.

The increase in batteries has kept CAISO focused on technical issues throughout the year, such as outage management enhancements, battery nonlinearity guidance and state of charge clarifications. The ISO also started an initiative to improve the visibility of distributed batteries, especially when they are needed for resource adequacy purposes.

CAISO will continue to lean on batteries in the coming year, specifically in the ISO's resource adequacy program and qualifying capacity (QC) process. Stakeholders asked CAISO to provide more clarity on how battery durations will be counted in CAISO's default QC counting rules, asking the ISO to avoid lumping all battery capacity together, including eight-hour batteries and four-hour batteries.

CAISO's DMM early in 2025 raised concerns about the potential gaming and inefficient bidding behavior in CAISO's bid cost recovery (BCR) process for battery storage resources. In an August *report*, DMM said the current BCR design creates gaming opportunities for battery storage units, "especially through manipulation of various biddable parameters used to manage state-of-charge." (See *CAISO Monitor Sees 'Gaming' Potential in Battery Storage Bid Cost Recovery*.) ■

CAISO headquarters in Folsom, Calif. | *© RTO Insider*

WRAP Builds Momentum, Faces Challenges in 2026

WPP Expects Program to Grow in 2026

By Henrik Nilsson

With 16 binding participants and 58 GW worth of load committed, the Western Power Pool's Western Resource Adequacy Program aims to build on the momentum in 2026 and prepare for more members.

Sixteen participants decided to remain in the WRAP before the Oct. 31 deadline to either exit or commit to the program's first "binding" — or penalty phase — season in winter 2027/28. (See *WRAP Wins Commitments from 16 Entities*.)

WRAP now has critical mass and will continue refining the initiative, WRAP Director David Zvareck and WPP Chief Strategy Officer Rebecca Sexton told *RTO Insider* in an interview.

"We've still got two more nonbinding forward showings ahead of us," Zvareck said. "Those are really the final opportunities for our participants to learn more about the program, get things dialed in and work on curing any deficiencies that they might have had."

Addressing deficiencies refers to members ensuring they are resource adequate ahead of the first binding season, Sexton noted.

"We're offering an RA program in the midst of a resource adequacy crisis," she said. "And in the time it's taken to get this program off the ground over the last six years, the crisis of resource adequacy has just gotten worse."

Interconnection requests from large load customers, such as data centers, coupled with supply chain issues make it difficult to keep up and build new generation, Sexton said.

"This makes the program more important but also means that participants have had to work really hard to close the gap so that they can be resource adequate when they go through the first binding season," she said.

With the WRAP being a requirement to participate in SPP's Markets+ day-ahead market, Sexton and Zvareck anticipate more entities to join the RA program in 2026.

"The notion of getting a whole group of new participants that could be larger than any we've seen so far is a new kind of challenge for us," Sexton said.

Zvareck and Sexton could not disclose the number of potential new members, but Sexton said there is "a lot of opportunity there to increase the diversity of the footprint … but it certainly could be quite a bit more work to onboard a larger group of folks than we have previously."

Day-ahead Market Impacts

Most of the 16 participants that committed to the WRAP plan to join Markets+. Meanwhile, five utilities withdrew from the program before the Oct. 31 deadline, including four that plan to participate in CAISO's Extended Day-Ahead Market (EDAM): NV Energy, PacifiCorp, Portland General Electric and Public Service Company of New Mexico.

> **Why This Matters**
>
> With a successful 2025, WRAP's leaders hope to attract more members in 2026 to help tackle increasing demand amid a resource adequacy crisis.

EDAM and Markets+ are set to launch in 2026 and 2027, respectively.

Exiting EDAM members cited high deficiency charges, concerns about Markets+ gaining more voting power in the WRAP and challenges operating under a divided Markets+ and EDAM footprint, among other issues. While WPP administers the WRAP, the technical platform is managed by SPP, prompting some participants to question whether EDAM participants can get equal treatment under the program.

Those concerns led some future EDAM participants to launch discussions in April 2025 about developing an alternative RA program for non-CAISO EDAM members, according to a Dec. 18 filing NV Energy submitted to the Public Utilities Commission of Nevada in response to questions about its decision to withdraw from the WRAP. (See *NV Energy Filing Reveals Extensive Talks Around EDAM RA Program*.)

The West-Wide Governance Pathways Initiative's Regional Organization for Western Energy has been floated as a potential overseer of an EDAM-aligned RA program. (See *Pathways' ROWE Could Offer Western RA Program, PGE Says*.)

Though the WRAP was conceived before the day-ahead markets, Sexton sees opportunities in leveraging them for the

BPA transmission lines near The Dalles Dam | © *RTO Insider* program's purposes. The program's Day-Ahead Market Task Force is exploring how it can adapt and ensure that both Markets+ and EDAM participants can reap its benefits. (See *WRAP Day-Ahead Market Task Force Looks to Future After Commitments, Withdrawals*.)

"The thing that's wonderful about the advancement of the day-ahead market existence — the paradigm that is about to be introduced here — is that they can start leveraging what connectivity does exist in a way that WRAP was never scoped to do," Sexton said.

For example, the task force is looking into how WRAP can use the day-ahead markets to share the resource diversity between the Northwest and Southwest, Sexton noted.

"It was clearly a priority of the Day-Ahead Market Task Force participants to continue to remain inclusive of a broader footprint and broader participation in WRAP," Sexton said. "So, it'll be important to us to be watching how we can not only lean into the Markets+ opportunities presented but also ensure that anyone not in Markets+ can still access the diversity and the benefits of WRAP and be a participant in the WRAP value proposition."

Seams Issues?

Zvareck said participants in both market camps are eager to collaborate and make the program work.

One concern with having two separate day-ahead markets is the potential for friction at their borders as entities join one market or the other. These seams arise from differing policies and separate dispatch between neighboring markets, which can result in additional costs for transferring energy across the boundary. (See *CAISO, SPP Explore Using Existing Tools to Manage DAM Seams*.)

The WRAP team will pay "close attention to the seams coordination discussions going on between CAISO and SPP because … there's an opportunity for that to better inform us how those will work," Zvareck said. He noted it is still too early to tell exactly how the seams will impact the WRAP.

When asked how much the exits from the WRAP impacted RA efforts and connectivity in the West, Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition, said a single RA program would be ideal.

"Over time, harmonization or at least liquidity for RA products with what's required in California would be even better," Gray said. "I have hoped that WRAP could provide that, and perhaps it will still evolve in that direction. The region certainly spent a lot of brainpower and effort to launch WRAP, and from NIPPC's membership, there are competitive retailers both in and out of WRAP.

"But setting aside some of the design challenges of WRAP for many load-serving entities, my overall perception is that while WRAP has predated both the EDAM and Markets+ tariffs and go-live dates, the financial importance in terms of trading volume and the organizational impact of a day-ahead market on participating entities have overwhelmed the value proposition of WRAP for some LSEs," Gray said. "Some kind of regional RA program and requirement remains highly valuable — to lower the planning reserve margins of individual LSEs and to avoid a dangerous game of musical chairs — but it can take several forms."

Fred Heutte, senior policy associate at the NW Energy Coalition, said WRAP participants are working to address the concerns of utilities that provided exit notices.

"Those utilities in turn continue to be involved in the WRAP for the next two years, and a lot can happen in that time," Heutte said.

For Heutte, one of the key RA questions in 2026 is how much demand from data centers and other new large loads will materialize. Already, there have been indications of a market correction on some of the higher forecast estimates, he said.

"Transmission facilitates resource adequacy," Heutte said. "A lot of effort is going into bringing advanced transmission technologies and new power lines onto the grid."

Heutte pointed to the Western Transmission Expansion Coalition study plan, which is set for public release Feb. 4. The WestTEC effort, jointly facilitated by the WPP and WECC, will address long-term interregional transmission needs across the Western Interconnection. The goal is to produce transmission portfolios for 10- and 20-year planning horizons. (See *WestTEC Targets Early 2026 for Release of 10-year Tx Outlook*.)

WestTEC is just one example. Efforts are underway in California and Oregon, and Portland General Electric has struck a deal with a data center to bring behind-the-meter batteries to address local RA concerns. The Bonneville Power Administration has launched initiatives to accelerate onboarding of new resources, Heutte noted. (See *Utilities Back Some BPA Transmission Updates, Hesitate on Others*.)

"And there are many, many other examples throughout the West," Heutte said.

A recent study by Energy and Environmental Economics predicts that accelerated load growth and aging power plant retirements will create a resource gap starting around 1.3 GW in 2026 and expanding to almost 9 GW by 2030. (See *9-GW Power Gap Looms over Northwest, Co-op Warns*.)

Heutte cautioned against interpreting the study as an emergency. He said reports from WECC and the Northwest Power and Conservation Council show the region can meet needs if resource efforts pick up.

"It is important over the next year to focus on the basics and not fall into complacency or panic," Heutte contended. "And it's not a matter of reliability *versus* affordability; both are essential. Everyone wins when the lights stay on and everyone can afford their energy bills. When it comes to resource adequacy in the West, we are surrounded by opportunity, but we have to make the effort now."

When discussions about launching the WRAP began in 2019, few could have predicted the resource crisis to reach the point it is at now, WPP's Sexton said.

"I don't think anyone could have imagined back in 2019 how much harder the resource adequacy problem would have become in the six years since then, or how much commitment we would have to this binding version of a program: more than 58 GW of load and great regional diversity," Sexton said.

"Our participants are solving that problem," she added. "They are the ones actually acquiring the resources, making the resource decisions, working on supply chain issues, and then working with us on the metric side and the program side to figure out how to properly stand up the program that they're committed to." ■

NV Energy's Early IRP Filing Reflects Load, Resource Challenges

Company Delaying Plans to Reduce Open Position

By Elaine Goodman

In mid-2023, NV Energy officials called the utility's reliance on short-term market purchases "risky and costly" and asked state lawmakers to declare that its open position should be closed quickly.

A year later, the company set targets in its 2024 integrated resource plan to reduce its open position.

Now, at the start of 2026, NV Energy says it will take longer than previously planned to reach its open-position targets. "Open positions" refer to resource needs that are met through short-term market purchases rather than by the utility's own resources or long-term contracts.

"We aren't able to have the decrease come as quickly as our plans from the 2024 IRP," said Janet Wells, vice president of resource planning. The delay is "in order to both consider the load needs as well as the resource availability in the short term."

Wells' comments came during a stakeholder briefing Dec. 18 about the company's plans to file its next IRP in April 2026.

The 2026 resource plan is coming two years after NV Energy's 2024 IRP, even though the company is only required to file a plan every three years. Nevada Assembly Bill 524, enacted in 2023, authorized NV Energy to file an IRP more often "if necessary."

The company has faced criticism for following each IRP with a series of amendments, often including proposals for high-priced new resources. Resources proposed in amendments, sometimes with a claim of urgent need, don't get the thorough review they would receive in a full IRP, critics say.

Why This Matters

As electricity demand surges in NV Energy's territory, the company is grappling with resource challenges including shifts in federal policy, expiring tax credits and renewable energy requirements.

AB 524 also instructs utilities to include in their IRPs a scenario in which enough resources are acquired to close the open position. That won't necessarily be the IRP's preferred scenario. (See *Bill Would Require NV Energy to Examine Market Reliance*.)

Early IRP Filing

NV Energy did not respond to emails asking why it is filing its next IRP early. But Wells pointed to possible reasons during her presentation to stakeholders.

The utility's projected load growth over the next 20 years is up roughly 25% compared to projections in the 2024 IRP, she said. At the same time, Wells said, the company is facing an array of challenges. Federal tax credits for solar and wind projects are soon expiring, and federal policy has shifted regarding solar and wind. Tariff impacts on imports remain uncertain.

Meanwhile, the Trump administration has emphasized the need for U.S. dominance in artificial intelligence.

And even as load is growing, NV Energy must still meet the state's renewable portfolio standard of 34% in 2026, 42% from 2027-2029, and 50% in 2030.

One resource strategy NV Energy is adopting is to prioritize projects that reduce or remove the need for permitting on federal lands.

"This way we would provide the greatest likelihood of delivery in the remaining critical years where production tax credits remain possible," Wells said.

Potential resources being evaluated include solar and storage — both paired and standalone — as well as geothermal and gas turbine projects.

Wells said there are potential projects that would use the utility's clean transition tariff, in which a large load customer brings their own generation. Those proposals would be submitted in a separate filing around the same time as the IRP.

In response to a question about how many megawatts of new resources would be from renewables compared to fossil fuel-fired resources, Wells said the company would share more information in the next stakeholder briefing, scheduled for Jan. 14.

Open Position Concerns

Brian Turner, director at Advanced Energy United, said NV Energy's delay in reducing its open position was "somewhat" concerning, given that "the overall market situation in the West is tightening."

NV Energy's decision in 2025 to withdraw from the Western Resource Adequacy Program was understandable, Turner said, but adds to the concerns.

"There's less transparency and less understanding of what's going to be available," Turner said.

That makes an alternative resource adequacy program being explored by NV Energy and other entities planning to join CAISO's Extended Day-Ahead Market all the more important, he added. (See *NV Energy Filing Reveals Extensive Talks Around EDAM RA Program*.)

Another issue, Turner said, is whether NV Energy's requests for proposals are robust enough given the growing demand. AEU is calling for reform to the company's procurement process.

Load Forecasts

Wells said the Jan. 14 stakeholder briefing would also include more details on NV Energy's load forecast.

In a base case forecast, large loads are "mitigated" — meaning requested loads are reduced by half if a line-extension contract has been signed or by 85% if there's no contract.

In addition to a base case, the company is analyzing two alternative scenarios. In one, growth from data centers and AI is removed. In the other, mitigations aren't applied to anticipated large loads.

The alternative scenarios are primarily for use in policy decisions, Wells said, rather than producing realistic forecasts. ■

RTC Deployed, ERCOT Takes on New Challenges

Interconnecting Large Loads, DRRS Among Top Priorities

By Tom Kleckner

AUSTIN, Texas — Having finally added real-time co-optimization to the market like every other U.S. grid operator with an effort that began in 2019, ERCOT can turn its attention to other pressing issues in 2026.

Of course, figuring out the most effective and efficient way to safely interconnect the hundreds of requests from large loads — data centers, bitcoin miners, large industrial facilities and the like — that have flocked to Texas' welcoming arms tops the list. The grid operator began the year with 63 GW of interconnection requests in its large-load queue but enters 2026 with more than 233 GW, up 269%. Data centers account for about 77% of that load.

Then there's ERCOT's continuing work on a dispatchable reliability reserve service (DRRS), a product that staff call an ancillary service but that some stakeholders don't. It is the third iteration of the product, mandated by state law in 2023 and a high priority for the Board of Directors and the Public Utility Commission.

A little less sexy initiative but equally important is the full-scale analysis that will take place in 2026 of the grid's reliability standard. It will be the first formal evaluation of the new reliability standard the PUC established in 2024.

But wait. ERCOT isn't finished with RTC. Nearly a dozen issues and tweaks have been identified to stabilize the market mechanism, requiring the task force that deployed RTC to stay active.

CEO Pablo Vegas says ERCOT is going through a transition "characterized by high and very rapid growth" of intermittent and short-duration supply resources.

"It's characterized by a rapidly changing customer base that includes price-responsive loads like crypto miners, rapidly growing large-scale data centers, and continued penetration of distributed energy resources throughout the grid," he told his board in December. "It's a significant shift in operational requirements, and it represents an opportunity to create a more resilient and cost-effective grid for the benefit of all Texans."

Vegas says ERCOT's load growth is "fairly unprecedented" and renders obsolete historical interconnection processes. As of November, the ISO had energized only a little over 5 GW of large loads in 2025. To remedy that, Vegas and other members of his leadership team proposed a new approach to interconnection called a "batch study" process. (See *ERCOT Again Revising Large Load Interconnection Process*.)

Keith Collins (right) responds to stakeholder questions during a December workshop on ERCOT's dispatchable reliability reserve service proposal. | *© RTO Insider*

Why This Matters

ERCOT's market is running real-time co-optimization, joining the rest of U.S. grid operators. But there are other meaty issues on the horizon, such as interconnecting the hundreds of gigawatts of large loads from data centers and bitcoin miners and adding another ancillary service.

Projects ready to be studied will be grouped together in batches and allocated existing and planned transmission capacity. ERCOT says this will provide large-load customers with study efficiency, consistency, transparency and certainty. The first group, Batch 0, will create a foundation and baseline for subsequent batches, building on the assumptions that have changed from the previous group.

Staff will develop the batch study's framework, taking input from market participants and regulators. ERCOT has rolled out a *stakeholder engagement plan* during January and February that includes six presentations to the PUC and stakeholder groups. It plans to file a proposed study process framework for discussion before the commission's Feb. 20 open meeting.

"There's clearly a pressure to move quickly and support the economic growth that's coming our way," Vegas told the PUC in December.

ERCOT Tries Again with DRRS

There's also pressure on ERCOT to produce the DRRS product, mandated by *House Bill 1500* in 2023. The law requires the grid operator to develop DRRS as an ancillary service and establish minimum requirements for the product: reducing the amount of reliability unit commitment by the amount of DRRS procured; and eligible resources being capable of running for at least four hours and be dispatchable not more than two hours after being called on for deployment.

Lawmakers followed up by *directing the PUC* to revise ERCOT's original protocol change to establish DRRS as a standalone ancillary service. The new direction resulted in allowing only offline resources to participate and the change was *withdrawn*.

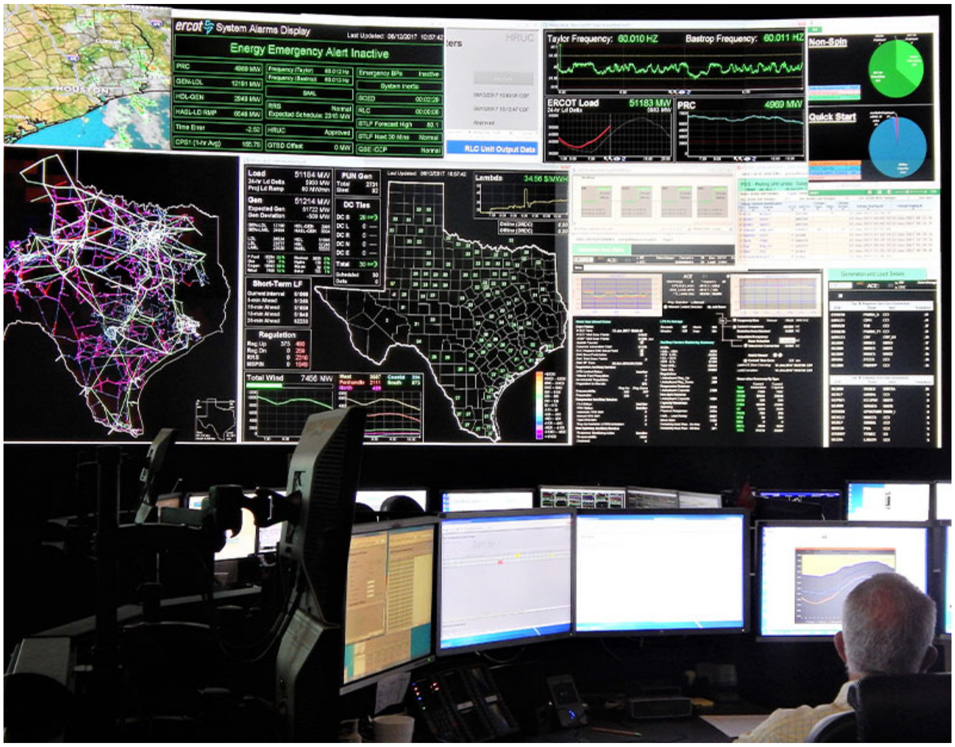
ERCOT now has filed a protocol change (*NPRR1309*) that meets all statutory criteria and improves the previous change by allowing online resources to also participate in DRRS. The new design enables the product to be awarded in real time and co-optimized its procurement with that of energy and other ancillary services under RTC.

An accompanying protocol change (*NPRR1310*) adds energy storage resources as DRRS participants and a release factor so the product can support resource adequacy. NPRR1309 has been granted urgent status and is due before the board for its June meeting. The same status has not been accorded to NPRR1310.

"We recognize there's likely to be a lively stakeholder debate," Keith Collins, vice president of commercial operations, told the board in December. "We are optimistic that it can move through the stakeholder process expeditiously, but we didn't necessarily want to burden it with a timeline for that."

ERCOT contracted Aurora Energy Research, which has a large local presence, to study future resource adequacy conditions and the effect of different market designs, including variations of DRRS. The research firm *determined* that DRRS' design adds more cost-effective dispatchable capacity and provides greater resource adequacy benefits in different load and extreme weather conditions. (See *ERCOT: New Ancillary Service Key to Resource Adequacy*.)

During a December workshop to review the report, stakeholders peppered Aurora staff with questions on the study. DRRS



ERCOT dispatchers monitor a system that now is co-optimized in real time. | © *RTO Insider*

is meant to achieve a revenue goal, not an operational goal, the firm's representatives said as stakeholders questioned whether it is an ancillary service.

Collins said the DRRS mechanism and its eligibility requirements strengthen reliability through ancillary services, whereas ERCOT's operating reserve demand curve, about 10 years old, uses energy to improve reliability.

"In our mind, [DRRS] is using ancillary services to achieve reliability, so it is an ancillary service plus," he said. "I'm not aware of any other market that has a tool quite like that."

Saying he doesn't understand how an ancillary service could ever procure 100% of eligible capacity, energy consultant Eric Goff, who represents the consumer segment, said, "It seems like that's a stretch to call it an ancillary service."

The workshop signaled the conversations that will happen over the next few months. ERCOT has scheduled another workshop for the Technical Advisory Committee on *Jan. 7*.

"Obviously, there'll be more discussion on 1309 and 1310 next month," Collins said.

Strengthening the Grid

After 2021's devastating Winter Storm Uri and the legislative session that followed, the PUC ordered ERCOT to create a *reliability standard* as a performance benchmark to meet consumer demand for three years into the future. The standard is composed of three criteria to gauge capacity deficiency: frequency (not more than once every 10 years), magnitude (loss of load during a single hour of an outage) and duration (less than 12 hours).

ERCOT and its Independent Market Monitor are required to evaluate the costs and benefits of any market design changes proposed to address deficiencies identified through the assessment process. The first such reliability standard assessment will be conducted in 2026 and then every three years and will include a forward review and analysis of the generation mix.

Vegas said in December that additional supply has been "helpful" in improving the grid's reliability characteristics.

"In the long term, there is increasing risk if the load materializes and infrastructure development doesn't keep up," he told the board.

ERCOT has deployed what it calls its "most significant" design change since its nodal market went live in 2010. The grid operator went live with RTC in early December and it has been successfully procuring energy and AS in real time every five minutes ever since. (See *ERCOT*

Successfully Deploys Real-time Co-optimization.)

"Mission accomplished. It was absolutely brilliant," ERCOT's Matt Mereness, who chaired the stakeholder group managing the effort, told the board in December.

The ISO says new functionality, which also improves the modeling and consideration of batteries and their state-of-charge in participating in RTC, will yield more than $1 billion in annual wholesale market savings.

However, there's still work to be done stabilizing RTC and transitioning to normal processers. Staff and stakeholders have identified *nine issues to further evaluate* in 2026. Those issues run from reviewing the ancillary service demand curve to evaluating concerns with AS deliverability and will be transferred to TAC.

ERCOT has identified five likely protocol violations and mitigation plans with the PUC and has filed a protocol change (*NPRR1311*) to reverse language allowing ancillary service prices above the $5,000/MWh cap during emergency conditions.

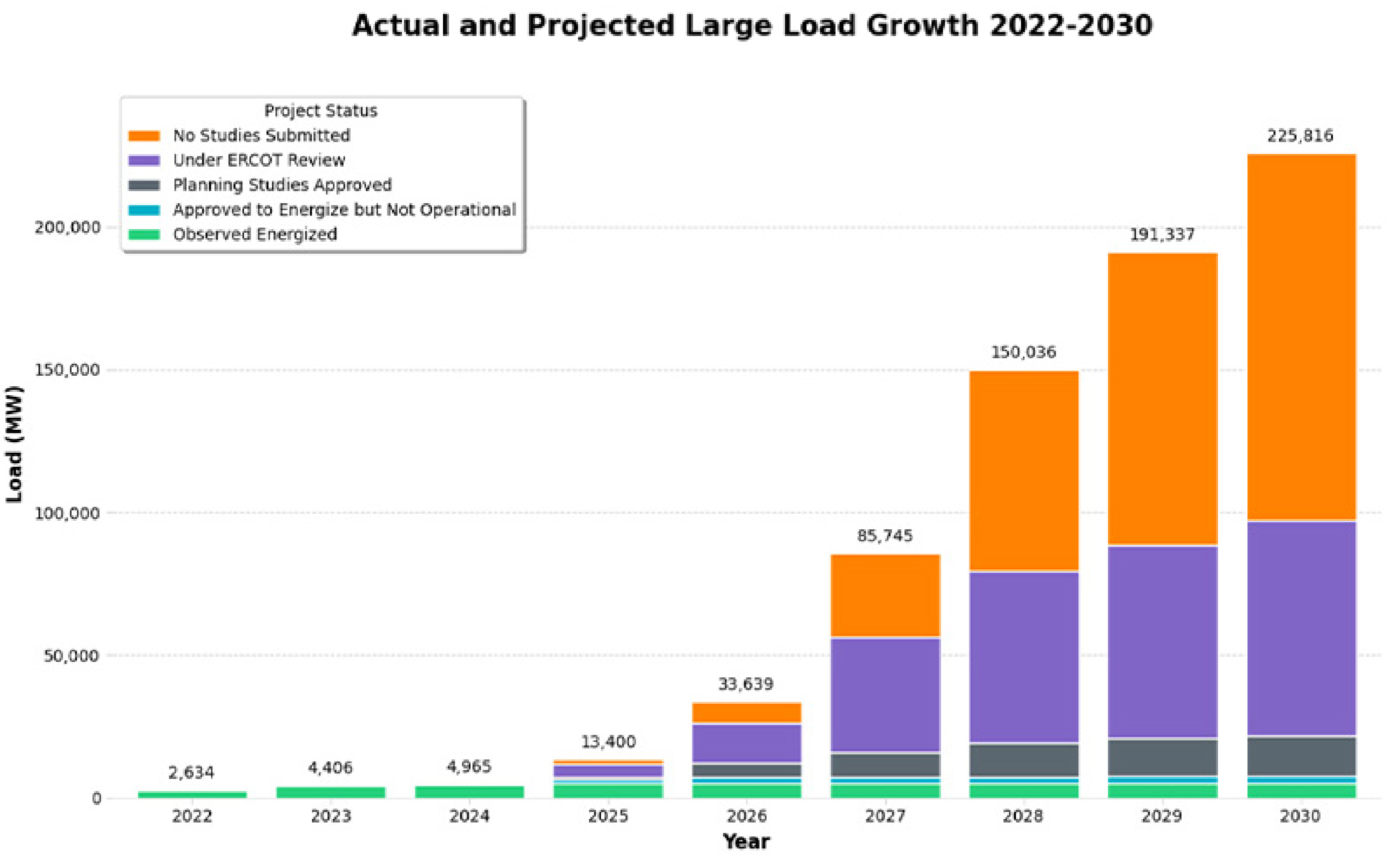
Mereness said the plan is to have everything resolved by Jan. 31. The grid operator will spend the first few months of 2026 releasing updates for remaining non-critical defects.

RTC's successful implementation is another plus for ERCOT and Vegas. He told the board during its year-end meeting that the ISO is determined to be the "most reliable and innovative grid in the world … in the world." (See "Vegas Sets Lofty Goal," *ERCOT Board Approves $9.4B 765-kV Project*.)

"We are one [of the best], if not the leading, grids globally when it comes to operational and technical complexities," Vegas said. To be successful, we need to be a clear leader on a stage that represents the entirety of this planet."

As part of its strategy to "advance knowledge sharing in grid innovations," ERCOT is hosting its third annual *Innovation Summit* on March 31 at a resort near Round Rock, Texas, where "visionaries, thought leaders and innovators" share ideas to address "challenges and opportunities facing grid operators around the world."

Or those thought leaders could just ask ERCOT staff, who already may be there. ■



Project Status	2022	2023	2024	2025	2026	2027	2028	2029	2030
No Studies Submitted	0	0	0	1,414	7,385	29,580	70,709	102,970	128,487
Under ERCOT Review	0	0	0	4,720	13,935	40,098	59,909	67,472	75,531
Planning Studies Approved	0	0	0	637	5,118	8,866	12,217	13,394	14,297
Approved to Energize but Not Operational	0	77	131	1,327	1,899	1,899	1,899	2,199	2,199
Observed Energized	2,634	4,329	4,834	5,302	5,302	5,302	5,302	5,302	5,302
Total (MW)	**2,634**	**4,406**	**4,965**	**13,400**	**33,639**	**85,745**	**150,036**	**191,337**	**225,816**

ERCOT's large-load interconnection requests as of November | *ERCOT*

IESO Sees 2026 Demand Cooling from 'Trade Tensions'

ISO 'Well Prepared' for Next 18 Months

By Rich Heidorn Jr.

IESO has reduced its 2026 demand growth projection slightly, citing "international trade tensions."

The revised projection came in its January 2026–June 2027 *Reliability Outlook*, which concludes Ontario is "well prepared" to meet its reliability requirements over the 18-month period.

IESO said firm energy demand rose about 2.3% in 2025 — "stronger than anticipated" — and will grow another 1.6% in 2026 and 1.1 % in 2027, with both peak and total energy demand to "moderate … as international trade tensions impact economic activity."

In its previous forecast on Oct. 7, IESO projected 2026 growth would be 2.23%.

The ISO says 2026 growth will be driven by numerous "large step loads" — electric arc furnaces, electric vehicle battery manufacturers and data centers — in addition to the electrification of transportation and industry.

Reserve Above Requirement levels — the margin between available and required resources — are above summer and winter thresholds and expected to range as high as 4,500 MW.

The latest demand forecast, released Dec. 18, is "broadly consistent with, though lower than, the previous forecast," IESO said. "In the longer term, the IESO continues to expect strong electricity demand growth."

The demand models use actual demand, weather and economic data through September, with data on large step loads incorporated in mid-October. Planned generator and transmission outages reflect plans reported as of November.

Reduced Supply

IESO will lose more than 2 GW of generation when the Pickering B Nuclear Generating Station goes out of service in October 2026 for a $26.8 billion *refurbishment* that will extend the lives of Units 5 to 8 for up to 38 years. Work is set to begin in 2027, with completion expected by the mid-2030s.

IESO hopes to add 185 MW in gas upgrades and 1,073 MW in battery storage and other resources from its Long-Term 1 procurements, which would leave the grid operator with a net reduction of 800 MW during the 18-month reliability horizon.

It also is counting on up to 260 MW of re-contracted capacity resources and more than 200 MW of re-contracted energy resources under its Second Medium-Term procurement.

The outlook does not include the results from the December 2025 capacity auction, which saw a record $645/MW-day (CAD) clearing price for summer 2026. "Forecast assumptions were based on capacity targets from the IESO's 2025 Annual Planning Outlook, and incorporating the actual auction results would not materially change the outlook," the ISO said. (See *Big Jump in Ontario Capacity Prices Signals Tightening Supplies*.)

The report said the refurbishment of the *Bruce* and *Darlington* nuclear plants remained on schedule, with work on Darlington Unit 4 expected to be completed in Q4 2026.

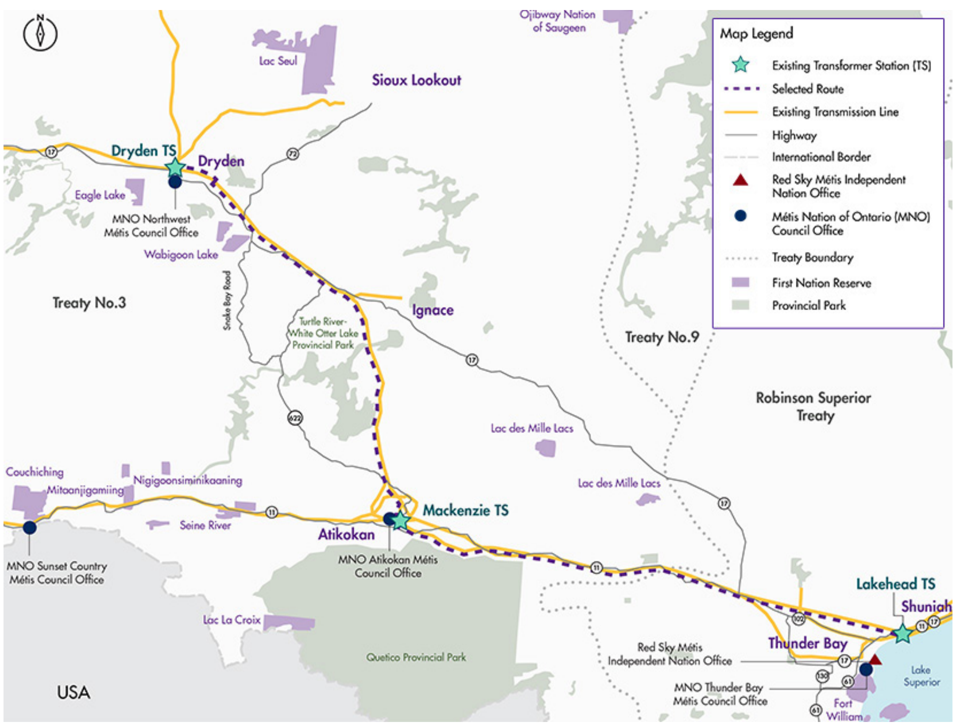
The ISO also is expecting completion of Phase 1 of Hydro One's *Waasigan Transmission Line Project* — including a new double-circuit 230-kV line between Lakehead TS and Mackenzie TS — by Q4 2026.

New Format

The outlook identifies risks that can be addressed by coordinating maintenance plans for generation and transmission facilities. The Q4 outlook is the first using a "more focused and concise" format, IESO said. Details on assumptions, explanations and terminologies were moved to the *Methodology to Perform the Reliability Outlook*. ■

Why This Matters

While the IESO says trade issues with the U.S. put a ding in Ontario's near-term demand forecast, the province's electricity consumption is still expected to grow at a decent pace.



Phase 1 of Hydro One's Waasigan Transmission Line Project — including a new double-circuit 230-kV line between Lakehead TS and Mackenzie TS — is expected to be completed by Q4 2026. | *Hydro One*

New England Betting on a Collaborative Approach in 2026

By Jon Lamson

Heading into 2026, the New England states, ISO-NE and energy industry stakeholders are counting on an increasingly collaborative approach to energy policy as federal opposition to renewable energy development threatens affordability, reliability and decarbonization objectives in the region.

As President Donald Trump ramped up his anti-renewable resource policy in 2025 — punctuated by the administration's Dec. 22 order halting all U.S offshore wind construction — the New England states moved forward with multistate transmission and generation procurements intended to meet forecasted load growth and state clean energy goals.

ISO-NE forecasts power demand to roughly double by 2050, and the RTO has expressed concern about resource adequacy starting in the 2030s, especially in light of the offshore wind industry's challenges.

How the region will meet growing demand in the coming decades is an unsettled question, and there is no certainty that the region's offshore wind industry will be able to rebound after the end of Trump's presidency. It also remains to be seen how effective the states' collaborative approach will be at supporting the continued growth of the region's power system.

While these questions may not be fully answered in the new year, 2026 will likely provide some important indications about the success of the states' approach, including results from a pair of major transmission procurement efforts. 2026 is also poised to be a crucial year for ISO-NE's ongoing effort to overhaul its capacity market, as the RTO has filed with FERC a potentially controversial set of resource accreditation and seasonal auction changes with a proposed effective date of March 31.

Why This Matters

Collaboration between states will likely be an important foundation for the buildout of the transmission and generation systems to meet demand in the coming decades, and 2026 should provide some early indications regarding the success of these efforts.

ISO-NE board Chair Cheryl LaFleur speaks at a public board meeting Nov. 5. | © RTO Insider

The recent political attention around energy affordability — which may be heightened by 2026 gubernatorial elections — likely will put pressure on ISO-NE and state officials to prioritize cost savings in all areas, including the capacity market changes and efforts to rein in spending by transmission owners on local transmission upgrades.

In an event in December, Gordon van Welie, who served as ISO-NE CEO from 2001 through the end of 2025, spoke about the improvements in stakeholder collaboration he saw during his 25 years at the RTO, saying, "Even when things do seem a bit tense, we've developed mechanisms to deal with those frictions."

2026 is poised to be a substantial stress test for New England's mechanisms to deal with energy policy frictions.

Accreditation Mad Dash

In 2026, ISO-NE and New England stakeholders face a heavy workload and a ticking clock in the effort to develop and build consensus around capacity accreditation changes and a new seasonal capacity auction design.

The changes are a major focus for a wide range of interests because of the potential effects on clearing prices and capacity revenues for individual resources.

The RTO first introduced its Resource Capacity Accreditation project in 2022 before expanding the project to include a wider array of changes, including to the timing of auctions and capacity commitment periods (CCPs).

On Dec. 30, ISO-NE filed the first phase of the Capacity Auction Reform (CAR) project, which proposes to drastically reduce the amount of time between auctions and CCPs and decouple resource deactivation from the auction process (*ER26-925*).

The RTO is poised to spend much of 2026 working to finalize the second phase of the CAR project, which includes accreditation changes and the development of a seasonal auction design splitting CCPs into six-month winter and summer periods.

Overarching affordability concerns may increase the stakes of the process. While the capacity market has not been a major driver of consumer costs in the region, state officials are eager to avoid the major capacity price spikes experienced recently in PJM and MISO. Some market participants in New England expect demand growth and Pay-for-Performance risks to push up prices in future auctions, and the proposed CAR changes add to the price uncertainty.

"Consumer affordability concerns and gubernatorial elections across the six states will heighten the political focus on all actions in this industry," said Dan Dolan, president of the New England Power Generators Association.

He emphasized the importance of "a cooperative structure of government policies and regulations" to help strike the right balance between reliability, affordability and clean energy investment, adding that "the public spotlight to get this right will be extraordinary."

The accreditation reforms would introduce several important factors into the capacity auction process, including gas supply constraints, on-site fuel storage, pipeline contracts, resource outage rates, battery duration and seasonal resource performance variability.

Resource accreditation values would be dynamic auction-to-auction, with changes in the region's generation and demand profile affecting the value of each resource.

ISO-NE is aiming to complete the accreditation and seasonal auction changes by the end of 2026, which may be no easy task given the high-stakes and potentially controversial nature of the reforms. The RTO hopes to have the full suite of CAR changes in place for its 2028/29 CCP. (See *NEPOOL Supports First Phase of ISO-NE Capacity Market Reform*.)

The RTO will also have to navigate the rocky waters of accreditation under new guidance; longtime COO Vamsi Chadalavada took over for van Welie as CEO at the start of January.

Chadalavada's appointment has been met with strong support from NEPOOL members, with some expressing optimism that he will build on the collaborative approach taken by ISO-NE in the first phase of the CAR project.

If ISO-NE is not able to complete the project and obtain FERC approval in time for the 2028/29 CCP, it may be forced to run the first phase of CAR changes as a standalone design, a circumstance that many stakeholders in the region hope to avoid.

Transmission, New and Old

Van Welie's tenure at ISO-NE was characterized, in part, by a strong reliability record and a major shift in the region's generation fleet as more efficient gas-fired plants replaced aging coal, nuclear, gas and oil generators. This transition was aided by investments in new transmission in the mid-2000s, which reduced congestion and allowed lower-cost resources to come online. (See *Retiring ISO-NE CEO van Welie Reflects on 25 Years at the RTO*.)

Chadalavada has assumed the leadership role amid another period of transition, characterized by demand growth and renewable power proliferation. The changing mix of demand and supply will likely require a large amount of new transmission investment over the next couple decades: A 2023 study by ISO-NE estimated that transmission upgrades needed to meet 2050 demand could cost up to $26 billion. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

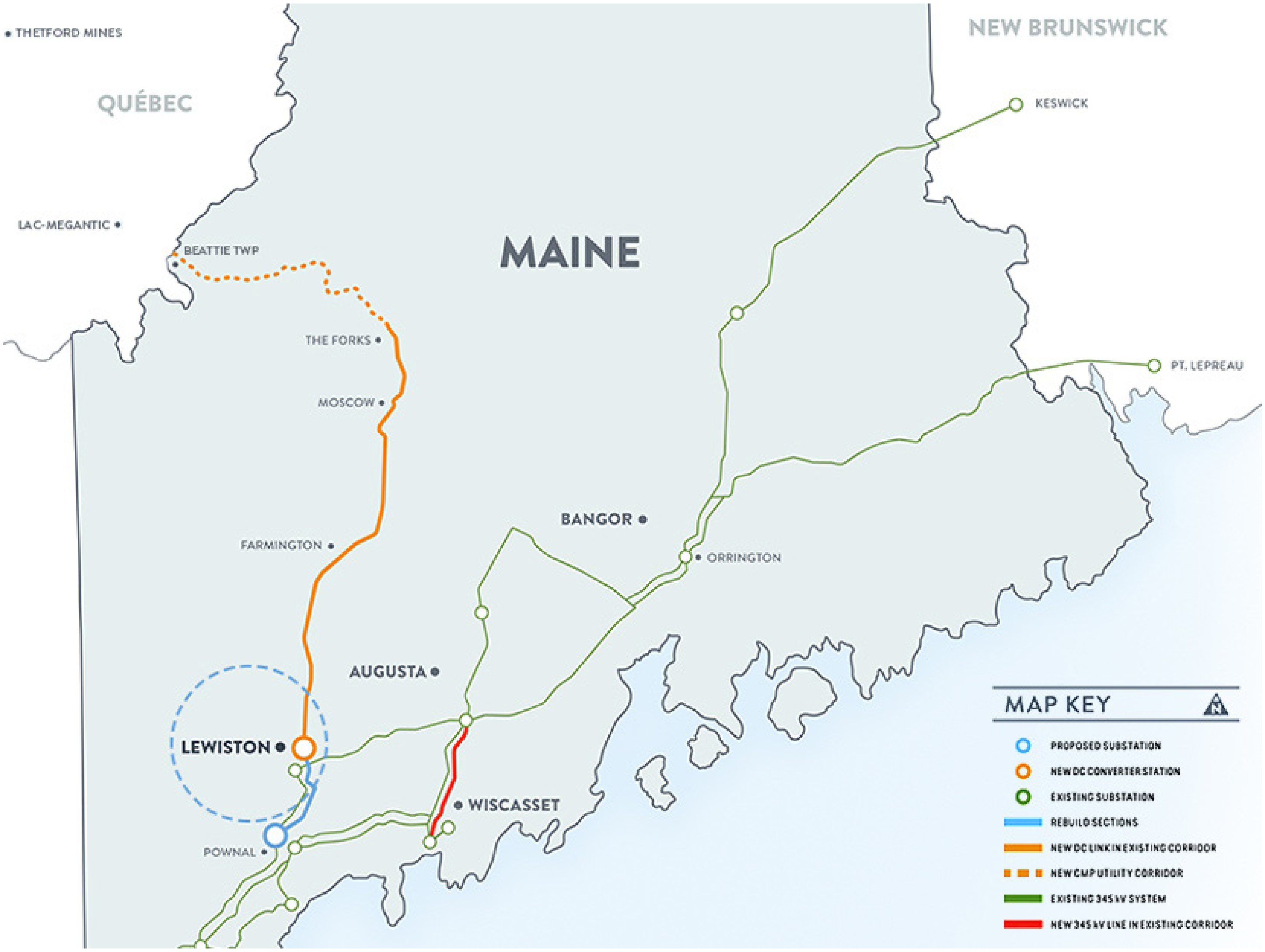
New England already has some of the highest transmission rates in the country, and long-term transmission needs could put significant additional pressure on transmission costs.

Given the anticipated long-term needs, consumer advocates are hoping to rein in some of the region's transmission spending through added scrutiny on asset condition projects. These upgrades account for the majority of the transmission investment in New England and have been a topic of growing concern for states and ratepayer advocates in recent years. In spring 2025, ISO-NE agreed to take on a non-regulatory role reviewing asset condition projects.

While ISO-NE has emphasized it will not make judgments on the prudency of transmission investments, its findings on projects could be used by other third parties in FERC proceedings to challenge investments. As it works to develop these internal review capabilities, the RTO plans to rely on a hired consultant to conduct reviews for a subset of asset condition projects.

State officials also have gone directly to FERC to seek relief; in mid-December, the Maine Office of the Public Advocate asked FERC to initiate evidentiary hearing procedures to investigate the prudency of asset condition projects placed in service in 2022. (See *Maine Public Advocate*

The Bokalift 1 and Bokalift 2 heavy lift vessels at the Revolution Wind site | *Revolution Wind*



NECEC project map | *Avangrid*

Asks FERC for Hearing on Asset Condition Costs.)

To address long-term transmission needs, ISO-NE and the states kicked off in 2025 the first transmission procurement under the new Longer-term Transmission Planning (LTTP) process. The solicitation is aimed at reducing transmission constraints in Maine to enable renewable development in the northern part of the state.

ISO-NE received six project submissions in response to its request for proposals in the fall, and it intends to select a preferred solution by September 2026. (See *ISO-NE Provides More Detail on Responses to LTTP Procurement*.)

To be eligible for selection, each project's estimated benefits must exceed its estimated costs. If no projects pass this threshold, the LTTP process allows states to opt to cover the extra costs, but it is unclear whether a state would assume this responsibility in the current environment of affordability concerns.

A successful first LTTP procurement could set a strong precedent for future procurements and other collaborative efforts among New England states, while a failed procurement would likely represent a significant setback for transmission development in the region.

In conjunction with the LTTP procurement, Maine has launched an additional solicitation of renewable energy and associated transmission in Northern Maine. The Public Utilities Commission published its RFP for the Northern Maine procurement on Dec. 19 and aims to select winning bids by the end of May 2026. (See *Maine PUC Issues Multistate Transmission, Generation Procurement*.)

Also in 2026, ISO-NE is slated to begin stakeholder discussions for its compliance with FERC Order 1920, which will likely build on the existing LTTP process.

"While our LTTP process is an excellent starting framework for planning and procuring regional-first beneficial transmission, Order 1920 will require further improvements that ISO-NE must incorporate into its practice, such as scenario-based planning, consideration of rightsizing and use of alternative transmission technologies," said Alex Lawton, a director at Advanced Energy United.

Long-term Energy Adequacy and Resource Development

While ISO-NE expects to have adequate resources to meet demand in the coming year, it has expressed concern about potential supply issues in the 2030s.

If able to complete construction, the Vineyard Wind and Revolution Wind offshore wind projects would provide a combined 1,500 MW of nameplate capacity to the region's grid. Vineyard is partly operational, and Revolution is nearing the completion of construction.

Susan Muller, senior energy analyst at the Union of Concerned Scientists, emphasized the potential winter cost and reliability benefits of these resources.

The power from Vineyard and Revolution "should make a significant difference in the overall wholesale cost of energy supply, which will benefit all retail customers in New England on an ongoing basis," Muller said, highlighting a study by Daymark Energy Advisors that found that 3,500 MW of offshore would have cut ISO-NE energy market costs by about $400 million in the winter of 2024/25. (See *New Study Highlights Winter Benefits of OSW in New England*.)

In a statement responding to President Trump's suspension of offshore wind construction, ISO-NE wrote that the affected projects "are particularly important to system reliability in the winter when offshore wind output is highest and other forms of fuel supply are constrained."

"While ISO-NE forecasts enough generation capacity is available for the current season, canceling or delaying these projects will increase costs and risks to reliability in our region," the RTO added.

The New England Clean Energy Connect (NECEC) transmission project — itself delayed by multiple years because of political challenges in Maine — should be online for the winter of 2026. The project includes a 20-year power purchase agreement for baseload energy from Hydro-Quebec, and ISO-NE *studies* have indicated the line will provide significant winter reliability benefits to the region.

Beyond NECEC and the two offshore wind projects, there is a high degree of uncertainty regarding the next wave of supply into the region.

Experts are somewhat divided on what the long-term effects of Trump-era policy will be on the offshore wind industry in the U.S. While some have expressed optimism that the industry will rebound with a new administration in Washington and continued state support, others have expressed doubt that investors will return.

"Unless it is a state entity or a federal entity building it, offshore wind is done in the United States," one analyst said at an industry conference in early December. (See *New England Energy Executives Debate Markets, Affordability*.)

With the looming July 4, 2026, construction deadline for solar resources to receive the federal investment tax credit, solar developers and state energy officials are scrambling to push late-stage projects forward as quickly as possible.

In a coordinated, expedited procurement led by Connecticut, four New England states recently selected a combined 173 MW of advanced-stage solar projects from across the region. (See *New England Coordinated Procurement Nets 173 MW of New Solar*.) Massachusetts also recently announced the *selection* of 1,268 MW of energy storage from a separate procurement.

"Our main focus next year is very tactical — working on project-execution-related matters for our portfolio, including asset financing, trying to advance some early-stage projects and looking for growth opportunities," said Aidan Foley, founder of Glenvale Solar, which had two projects selected in the recent solar procurement.

"We need a continued pace of procurements and long-term policy initiatives, both to bring near-term assets online and to communicate to developers [and] investors that there will be paths to market in the future," he added.

On the distribution side, solar developers are also working to start construction and bring projects online as quickly as possible.

"The first half of 2026 is going to be a sprint to get the last batch of projects in the door," said Jessica Robertson, director of New England policy and business development at New Leaf Energy. "Then, the next several years are going to be a really hard focus on getting things online by those ITC deadlines, and in parallel, trying to develop our storage verticals."

She noted there are several hundred megawatts of distributed solar in the various stages of Massachusetts' interconnection queue.

To help expedite the development process, she said it will be important to increase the frequency of Affected System Operator studies and potentially enable rolling determinations of whether a project needs a study.

In the long-term, New Leaf is looking at "figuring out how to keep solar going without the ITC," Robertson said. "That's not going to work everywhere right away, but certainly states like Massachusetts don't plan to stop after next July." ■

MISO Vows Greater Generation Totals for Big Tech in 2026

By Amanda Durish Cook

MISO has indicated that new generation to serve data centers and other large loads will be mission critical over 2026 and said it will take pains to interconnect units.

The grid operator also will plan accordingly for fewer renewables in the footprint in the future and will embark on long-range transmission planning for its Southern load pockets.

Entergy Texas' Orange County Advanced Power Station under construction in late 2025 | *Entergy*

'Speed to Power' + Fast Pass Gen Projects

MISO CEO John Bear said speed to power will be MISO's theme in 2026, as it is nationally. He said MISO's interconnection queue fast lane is working as intended to sate demand.

"The first cycle of GIAs is signing within days, not years," Bear reported at MISO's Dec. 11 board meeting.

MISO created a temporary queue express lane to get necessary generation online faster. Throughout 2026, MISO will welcome four more 15-project cycles into its interconnection queue express lane.

The first two cycles of projects are composed overwhelmingly of gas generation. MISO expects the 11 GW of new natural gas generation from the first two classes of its fast lane to begin coming online in 2028. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

MISO Senior Vice President Andre Porter | *© RTO Insider LLC*

Bear said MISO is working to condense timelines in the ordinary interconnection queue. He said regular queue phases are "shrinking dramatically" and can now be measured in days, not years.

"We have to be faster, and we have to be better," Bear told stakeholders, members and board members.

MISO has vowed to ease the process to bring co-located generation and load online sooner, trying to move as fast as new large loads demand. The RTO said it may create interconnection agreements where generation is barred from injecting into the MISO system. The design work would take place over 2026. (See *MISO Floats 'Zero Injection' Agreements to Bring Co-located Gen Online*.)

MISO Senior Vice President Andre Porter said MISO today has 180 GW of installed capacity, 138 GW of that accredited. He said though MISO contains more gigawatts than it did a decade ago, its accredited capacity values have remained flat. However, he said members are making demonstrable progress on the RTO's supply.

MISO reported that its three-year historical supply additions increased over 2025 from 4.7 GW to an estimated 6.7 GW annually. But Porter added that incremental load growth by 2030 also increased over 2025, up to 23 GW from an 18-GW estimate just months earlier.

"Members are making real progress in terms of additions they're making. There's significant momentum in the MISO region that's going to allow us to rise above the noise," Porter said, referring to the daily headlines on growing demand.

Porter said MISO has a goal to complete 25 generator interconnections per quarter over 2026 and 2027. He said MISO likely will need to sign on 8 GW of accredited capacity per year to continue to meet resource adequacy targets.

"You're going to see much more speed within the generator interconnection queue," Porter promised members a Dec. 10 Advisory Committee meeting. He said MISO understands that the queue "can no longer be an impediment" to generation development.

MISO's regular generator interconnection queue contains 910 projects at 169 GW, much lower than the more than 300 GW MISO began 2025 with. Developers have *withdrawn* 129 GW worth of projects over 2025 since the Trump administration announced a phaseout of tax credits for renewable energy. MISO has yet to factor in the projects that queued up for the 2025 cycle. The RTO warned that the regular queue will fluctuate over the first half of 2026 as more developers remove projects and as it adds 2025 projects.

MISO, by its *estimate*, will field expedited transmission requests to support 13.1 GW in load growth throughout 2026. MISO approved expedited transmission projects to support 9.7 GW of large load additions in 2025.

"Since we've closed our [Transmission Expansion Plan] process in September, we've had more requests for expedited review than in all of 2025. And last year was multitudes of the year before," MISO Executive Director of Transmission Planning Laura Rauch reported at the MISO Board of Directors' System Planning Committee meeting Dec. 9.

Load Grows Where Data Centers Go

MISO Senior Vice President Todd Ramey said MISO members' load forecasts show an uptick in load around 2027, when the net coincident peak could pass 130 GW.

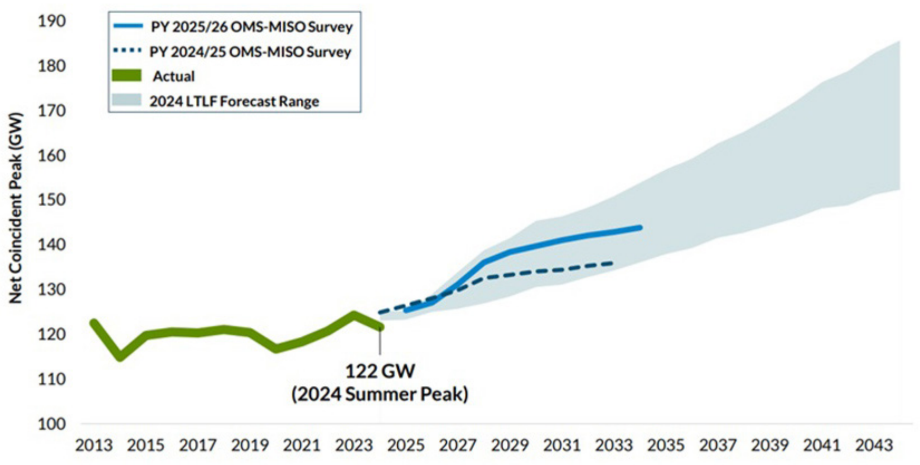
"We're pretty tight on surplus capacity here, so I think this shows a need to focus on getting accredited capacity online as load growth continues to pick up," Ramey said during the RTO's June Board Week.

MISO's 2025/26 Planning Resource Auction showed capacity is at a premium in the footprint — at least during summer when prices soared to $666.50/MW-day. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Fewer Future Renewables

The RTO reported that it noticed a drop in members' plans for standalone renewable energy and increasing plans for dispatchable resources.

Rauch said MISO clocked a sizable difference between the future generation plans its members submit now versus what they submitted a few years ago. She said members foresee more thermal, dispatchable energy within 20 years. MISO has said more on-call energy will prove useful to combat load growth.



MISO members' combined load forecasts. MISO's range of load forecasts are represented by the shaded region. | MISO

MISO has reported that since 2024, its members' plans for new, dispatchable resources jumped from 32 GW to 50 GW by 2043. Plans for standalone renewable energy, on the other hand, dropped from 103 GW to 55 GW. MISO said it noticed the sea change from surveying its members about their plans for its 2024 Regional Resource Assessment and again in 2025 as part of the OMS-MISO Resource Adequacy Survey.

Despite the renewable slowdown, MISO expects to have about 40 GW of installed solar capacity at the end of 2028.

By 2045, MISO believes it could have anywhere from 383 GW to 454 GW of installed capacity, with a bigger natural gas generation buildout and fewer renewable energy resources. (See *MISO Draft Tx Planning Futures Envision 400-GW Supply or More by 2045*.)

"We're expecting to see a significantly more balanced system" than before, Porter said.

But MISO's four transmission planning scenarios, to be finalized in spring 2026, don't allow for much energy storage, a detail MISO Director Barbara Krumsiek asked about during MISO's quarterly Board Week in December.

Rauch said MISO's reworked versions of the future simply don't contain as much excess energy production from renewable energy, making storage a less compelling avenue.

At a Dec. 10 Advisory Committee meeting, Clean Grid Alliance's Beth Soholt urged MISO not to underestimate storage expansion and consider giving it a broader use category in the markets.

"It's like bacon. It makes everything better. Add it to a sandwich and it tastes better," Soholt joked.

Soholt said MISO's market rules for storage can either be a "barrier or a facilitator."

More DOE Emergencies, More Thermal Resources

Porter said MISO expects to receive more emergency orders from the Department of Energy to keep thermal resources online. However, he said some members themselves might be considering delaying retirements on some of those units.

"The thought is that perhaps we won't need as many of those orders moving forward," Porter said.

Since May, there's been no end in sight to DOE's interventions to keep a Michigan coal plant online. The Department of Energy in fall ordered Consumers Energy's J.H. Campbell coal plant to delay closure through the winter. But MISO and its Independent Market Monitor said J.H. Campbell did not clear the planning resource auction and was not needed for resource adequacy. (See *MISO: Retirement-delayed Campbell Coal Plant not a Capacity Resource*.)

According to Yes Energy data, the 1.45-GW plant had an average 70% capacity factor over June and July 2025.

Ramping Needs

With a solar fleet capable of a 14.5-GW

peak and set to double over 2026, MISO will pay more attention than it ever has to its steeper ramping needs, which have risen dramatically with a growing renewable fleet.

Zak Joundi, executive director of markets and grid strategy, said MISO will design a process to dynamically set requirements for ramp capability and regulation reserves throughout 2026.

MISO must "clear the right products in the right areas," Joundi told the MISO Board of Directors in early December. However, Joundi said while designs would be more computationally complex, MISO would stop short of clearing ancillary services on a nodal basis, like its real-time energy market.

MISO South Long-range Tx Plan an Open Question

MISO will turn its attention to long-range transmission planning for the most constrained load pockets in its South region. The RTO has pledged to conduct a risk assessment as part of its first long-range transmission effort in MISO South in 2026, focusing on load pockets across Louisiana and southeast Texas.

But don't expect multibillion-dollar transmission portfolios like those designed for MISO Midwest. The RTO's planners will take a more measured approach with the South. (See *MISO to Include Southeastern Texas in South Long-range Tx Planning*.)

Rauch said MISO would "practice what a long-term transmission plan and risk assessment will look like" with its South stakeholders over 2026. She said MISO won't propose solutions until it and stakeholders can review results of the risk analysis and better understand whether generation, transmission or something else might be needed.

"We don't want to commit to anything until we see those," Rauch said. She added that MISO could conduct more assessments after the initial risk assessment to further flesh out solution decisions.

MISO's South planning announcement was prodded in part by a late May 2025 load shedding incident in New Orleans. Repercussions from widespread blackouts in the New Orleans area are to reverberate into 2026 as MISO has promised to launch a new transmission warning system. (See *MISO to Debut Tx Warning System in 2026*.)

Finally, MISO in 2026 will manage planned transmission outages related to construction of its first, $10.6 billion batch of long-range transmission projects in MISO Midwest that were approved in 2022. Executive Director of System Operations J.T. Smith said the construction is expected to alter MISO's usual congestion patterns.

Smith said "good, solid outage coordination" will be key, alongside reflecting changes in MISO's financial transmission.

"It is going to be impactful. There are going to be some right of ways that we lose access to for a while," Smith told MISO directors at a Dec. 9 Markets Committee of the Board of Directors.

Bear agreed that outage coordination will be key as the first long-range transmission projects are built. MISO expects the largest disruptions from LRTP project construction in 2026, 2027 and 2028. ■

NYISO's 2026 to be Dominated by Reliability Concerns

By Vincent Gabrielle

At the final Management Committee meeting of 2025, NYISO CEO Rich Dewey addressed stakeholders and staff, thanking them for their cooperation and work during a full, "challenging" year.

"When we started the year, we talked a lot about our concerns we had with respect to reliability," said Dewey, who went on to list aging generation and explosive load growth as key drivers of reliability concerns. "Some tough decisions were made through the course of the year. … I am really happy and confident where we landed thinking about the planning process."

Dewey warned stakeholders and staff that 2026 would be just as full, if not fuller, than 2026.

"If I told you 2026 was going to be easier, you should not believe me," he said. "We have a lot of continued work ahead of us, and so it's going to be a challenge to address the issues that we have on our plate already."

Chief among those challenges are the upcoming discussions on changes to the reliability planning process. Stakeholders recently approved a Comprehensive Reliability Plan that calls for structural changes to the process. (See *NYISO Reliability Plan Calls for 'New Dispatchable Generation'*.) NYISO wants to move planning from a "reactive posture" to a more proactive approach accounting for a wider range of outcomes in reliability planning rather than a single expected future. The ISO also called for new dispatchable generation. This angered environmental stakeholders, who accused the ISO of endorsing fossil fuel-fired development in all but name.

Most of the specifics of how the reliability planning process would determine needs were left open to discussion.

Why This Matters

Increasing uncertainty and thinning margins are pushing NYISO to reconsider its reliability planning.

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During an Operating Committee meeting Oct. 16, Ross Altman, NYISO senior manager of reliability planning, said discussions with stakeholders would need to happen in order to determine which range of forecasts would be considered actionable. (See *NYISO Notes 'Fluctuation' of Outlooks for Grid Reliability*.)

New York City Reliability Need

The third-quarter Short-Term Assessment of Reliability (STAR) found there was a reliability need in New York City. This is the second year in a row a reliability need was found for the city. (See *NYISO Again Identifies Reliability Need for NYC*.) The city could be 650 MW short by the summer of 2026 if the Champlain Hudson Power Express (CHPE) does not come online on time.

The STAR also found reliability needs for Long Island and the Lower Hudson Valley in 2027 and 2030, respectively, but neither are as large as New York City's.

The findings triggered a formal process in which the ISO will seek solutions to the issue, including transmission, generation and energy efficiency, either alone or in combination. The process is sure to dominate stakeholder discussions for months in 2026.

The shortfall is driven primarily by the impending retirements of the Gowanus and Narrows gas generators in the city. These generators are being kept online by an ISO reliability designation under New York state's peaker rule. If CHPE and Empire Wind complete on time, they would, according to the ISO, solve the deficiency.

The previous year's reliability need was "solved" by considering certain large loads, including cryptocurrency mines and hydrogen electrolysis plants, "flexible," meaning that they would not operate during peak hours for economic reasons. (See *NYISO: Large Load Flexibility Eliminates 2034 Shortfall Concern*.)

With the rapid proliferation of inflexible, "always on" data centers in the interconnection queue and this year's reliability shortfall coming from a lack of generation, it is less likely that a similar solution will present itself to NYISO. Until CHPE and Empire Wind are completed, the ISO is in an awkward position of trying to solicit solutions for a problem that may solve itself.

Resetting the Demand Curve Reset

Late in 2025, NYISO began discussion with stakeholders about how the demand curve reset process would be reformed. It is highly likely that this will continue to dominate stakeholder meetings in 2026. The DCR sets capacity prices every four years based on the capital costs of a new generator on the market.

DCRs are time and resource intensive and contentious between stakeholder sectors.

Even though both stakeholders and NYISO staff identified the DCR as a priority during the Capacity Market Structure Review project, it is likely that any changes to the process will also be controversial between stakeholder sectors.

An issue discovery report was supposed to be presented to stakeholders at the final Installed Capacity Working Group meeting of the year, but it was not on the agenda. (See *NYISO Begins to Discuss Demand Curve Reset Process Changes*.) It is unclear when this report will be presented.

A Possible Hudson Valley Power Authority?

Late in the year, a coalition of environmental groups, local activists, politicians and electricity consumers released the results of a *feasibility study* that found that the Hudson Valley Power Authority Act, which was introduced in the state legislature in 2025, could save the Central Hudson Gas & Electric system, including ratepayers, *$15.2 million* after its first year of passage. By Year 30, these savings would climb to $210.5 million annually, a 12.7% difference in rates and saving $2.9 billion cumulatively.

The bill would allow the state to acquire Central Hudson's assets and convert the utility to a nonprofit utility. The purchase price would be roughly $3.5 billion.

"This is a common step in municipalization and other public ownership campaigns," said Sandeep Vaheesan, legal director of the Open Markets Institute. "At a minimum, the purpose is to show that this is a practical choice in terms of dollars and cents."

NewGen Strategies and Solutions, a management and consulting firm, conducted the study on behalf of the coalition. The firm said the savings would be realized primarily by not paying profits to shareholders, issuing cheaper debt and being exempt from state and federal taxes.

"The question is, could they acquire and operate the utility at a lower cost to ratepayers?" said Scott Burnham, a partner at NewGen. "One of the critical elements of the analysis is that we did not conduct an appraisal of these assets. … We looked purely at publicly available information."

Central Hudson has come under political fire for requesting double-digit rate hikes in 2024, followed by another *rate case in 2025*. In response to rising energy bills, lawmakers passed a bill that requires utilities seeking rate increases to "fully and publicly explain all capital expenditures included in the request." The bill passed after the Public Service Commission *approved* a three-year rate hike package over the *summer*.

"There's a lot of discontent with Central Hudson in the Mid-Hudson Valley, specifically over rates," Vaheesan said. "There's a widespread view that Central Hudson has been seeking and obtaining aggressive rate increases and that their service record is mediocre."

The New York Times reported that Fortis, the owner of Central Hudson, had no interest in *selling*. A spokesperson for Central Hudson told the *Times Union* that any attempt to purchase the company would only result in a drawn-out and costly legal battle. ■

PJM Pushing Forward on Efforts to Meet Rising Data Center Load

By Devin Leith-Yessian

PJM CEO Manu Asthana | © *RTO Insider*

PJM enters 2026 amid several efforts to ward off a reliability gap attributed to accelerating data center load, sluggish development of new capacity and resource deactivations.

The risks were laid bare in December, when the 2027/28 Base Residual Auction cleared 6.6 GW short of the reliability requirement. Of the 5,250 MW of load growth included in the auction, the RTO attributed nearly 5,100 MW to data centers. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

With six months remaining before the 2028/29 BRA is to be conducted in June, PJM's Board of Managers is considering how to proceed in the wake of a Critical Issue Fast Path (CIFP) proceeding focused on large load interconnections. Stakeholders brought forward a dozen proposals, none of which received sector-weighted support from the Members Committee on Nov. 19. During the committee's meeting Dec. 17, board Chair David Mills pushed the target for a FERC filing to January to allow more time to go through the packages. (See *PJM Stakeholders Reject All CIFP Proposals on Large Loads*.)

The rejection of the proposals puts the board in a similar position towhen the RTO conducted a CIFP in 2023 focused on resource adequacy, when 20 packages were rejected. Because the committee's vote is only advisory, the board could choose to proceed with any of the options, cobble together elements of them or arrive at its own solution. PJM staff's recommendation included a request for a second phase of the CIFP to evaluate changes to the reliability backstop and incentives for load flexibility. (See *PJM Stakeholders Vote Against All CIFP Proposals*.)

Why This Matters

Proponents of co-location have argued it allows for more efficient siting of load, reducing the need for transmission upgrades, while skeptics say it would push transmission and ancillary service costs, such as black start, onto other consumers.

The board is weighing its options against the backdrop of a FERC order directing PJM to revise its tariff to include at least four options for large loads co-located with wholesale generation to receive transmission service. It also directed the RTO to provide a report on the CIFP within 30 days of the Dec. 18 order. PJM has scheduled a workshop to discuss the co-location order Jan. 9. (See *FERC Directs PJM to Issue Rules for Co-locating Generation and Load*.)

Proponents of co-location have argued it allows for more efficient siting of load, reducing the need for transmission upgrades, while skeptics say it would push transmission and ancillary service costs, such as black start, onto other consumers. Independent Market Monitor Joe Bowring and several other stakeholders have argued that if loads are considered critical national security interests, it is unlikely that they would actually be required to curtail or accept non-firm service.

Further complicating the board's deliberations is a complaint the Monitor has filed with FERC arguing that PJM has the authority to delay large load interconnections that would jeopardize transmission security or resource adequacy (*EL26-30*). It argued that the recommended CIFP proposal — and PJM's statements throughout the process — are based on an untested theory that the jurisdictional contours that RTOs operate within do not allow them to require that a load can be served reliably before it is permitted to enter service. (See *Market Monitor Files Complaint Over PJM Large Load Interconnections*.)

Several Design Changes for June Auction

Several design changes are to affect the 2028/29 auction, including the elimination of a price collar established by a settlement with Pennsylvania Gov. Josh Shapiro (D); the implementation of FERC Order 2222 requiring RTOs to facilitate the participation of distributed energy resources; and the expiration of a measure allowing PJM to model some deactivating resources operating under reliability-must-run agreements as providing capacity. The 2029/30 BRA is scheduled for December 2026.

The price cap was effective for the 2026/27 and subsequent auction, limiting prices to between $175 and $325/MW-day, with adjustments before each to account for shifting accreditation values for the combustion turbine reference resource. The temporary nature of the agreement was intended to avoid high prices while several market changes are implemented. Supporters argued the RTO's backlogged interconnection queue would prevent developers from responding to high prices.

During a press conference following the posting of the 2027/28 auction results, PJM Executive Vice President of Market Services and Strategy Stu Bresler said staff plan to proceed with the 2028/29 BRA with the auction parameters proposed in the RTO's Quadrennial Review filing. (See *PJM Board of Managers Approves Quadrennial Review Proposal*.)

A joint proposal from the Data Center Coalition, Exelon and PPL, as well as the governors of Maryland, New Jersey, Pennsylvania and Virginia, would extend the collar by one year, in addition to adding financial requirements for large loads, creating a demand response product with limited annual run hour restrictions and loosening the participation requirements for the expedited interconnection track proposed by PJM. (See "Data Center Coalition, Utility and Governor Proposal," *PJM Stakeholders to Vote on Large Load CIFP Proposals*.)

The governors, along with those of Delaware and Illinois, signed a letter encouraging the board to include an extension of the collar in the CIFP solution it accepts.

The commission's approval of PJM including the 1,289-MW Brandon Shores and 397-MW H.A. Wagner in the capacity supply stack is also to end prior to the 2028/29 auction. Its temporary nature was similarly intended to allow resources that consumer advocates argued can operationally serve as capacity to be modeled as such while stakeholders pursue a more holistic approach to how RMR resources are reflected in the capacity market. PJM has said it intends to request a one-year extension of FERC's approval. (See "PJM Plans to Request 1-year Extension of RMR Resources Participating in Capacity Market," *PJM Board Releases Outline of Capacity Market Changes*.)

The Deactivation Enhancements Senior Task Force is continuing discussions on a *pro forma* RMR *agreement* that would allow the RTO to dispatch relevant resources during a capacity emergency.

PJM Files Quadrennial Review

PJM is awaiting a FERC decision on its Quadrennial Review filing, which would set the auction rules for four years starting with the 2028/29 BRA (*ER26-455*). (See *PJM Board of Managers Approves Quadrennial Review Proposal*.)

The proposal would rework the design of the variable resource requirement (VRR) curve to set the maximum price at the larger of either 20% of the gross cost of new entry, or 115% gross CONE minus 75% of the net energy and ancillary services (EAS) offset. The formula establishes a floor meant to prevent high energy market revenues from lowering the maximum capacity price to zero. The curve approved by the commission in 2023 set the maximum at the greater of gross CONE or 1.75 times net CONE, which subtracts the EAS offset from gross CONE.

Jointly proposed by PJM staff and Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow, it is meant to improve the stability of the VRR curve by reducing reliance on multipliers of the CONE parameter. The curve defines the clearing price to be procured in a BRA and at what cost.

The reference resource would remain a combustion turbine, though PJM's initial proposal would have shifted to a combined cycle generator for all regions except in ComEd, where a four-hour battery electric storage system would be the reference. (See "Stakeholders Divided on Reference Technology," *PJM Stakeholders Discuss Quadrennial Review Proposals*.)

The filing has been opposed by the Monitor, which took issue with PJM's VRR curve shape, and the Maryland Office of People's Counsel, which sought a Federal Power Act Section 206 investigation into the functioning of the RTO's capacity market.

The Monitor disputed PJM's calculation of gross CONE for the reference resource and argued the proposed VRR curve would inflate capacity costs by $6.7 billion, instead recommending a steeper curve.

The OPC argued that PJM's filing would result in uncompetitive market outcomes so long as developers cannot respond to high prices because of a confluence of the compressed auction schedule, the amount of time it takes projects to clear the interconnection queue and national supply chain shortages. It argued the commission should investigate the ca-

PJM board Chair David Mills | © RTO Insider LLC pacity market and extend the maximum price set by the proposal until it determines "new entry imposes constraints on the potential exercise of market power."

Transition to Cluster Cycles to Complete

PJM is about halfway through processing projects being studied in Transition Cycle 2 of its interconnection queue, which is currently in the second of three phases. Interconnection service agreements are to be negotiated between December 2026 and February 2027.

The cluster-based approach for studying the network upgrades needed for new resources and how costs are allocated is to begin with its first cycle once the April 27 application deadline expires. Reviewing the applications will take a few months, and models are to be posted in June. The total cycle is expected to continue through April 2028.

The shift is intended to allow projects to proceed through the queue more quickly and give developers more certainty about the costs they may face. The backlogged queue has often been blamed for holding back new resources, particularly renewables, contributing to the imbalance of supply and demand. Since it implemented its transitional process, PJM has said it is processing more projects than ever — including 306 interconnection requests when Transition Cycle 1 was completed in 2024. (See *PJM Reaches Milestone on Clearing Interconnection Queue Backlog*.)

Leadership in Flux

PJM leadership is in a moment of transition going into 2026, with two new board members appointed in September and Chair Mills assuming the interim CEO position for "several months" as the search continues for a long-term executive. (See *PJM Members Confirm 2 Board Nominees; States Call for Governance Overhaul*.)

Speaking during the Dec. 17 MC meeting, Mills said PJM was "incredibly fortunate" to attract outgoing CEO Manu Asthana in 2019, as the leading indicators of the challenges the RTO would face began to emerge. (See *PJM Taps Ex-Direct Energy Exec as New CEO*.)

Asthana recalled being gifted a firehose at his first MC meeting, which he called a fitting sign of what was to come. He said Mills is more than ready to take over and has his full confidence.

Several governors of PJM member states have pushed the RTO to rework its governance structure to provide more of a voice for the states in its decision-making. Following a multistate technical conference in September, they issued a statement of intent to form a PJM Governors' Collaborative to "promote greater state and consumer representation in the governance and decision-making processes of PJM." (See *Governors Call for More State Authority in PJM*.)

The participation of governors' offices and state legislators in PJM's stakeholder process deepened throughout the CIFP, and Pennsylvania separately sponsored an issue charge to explore a sub-annual capacity market design. The Analysis Group *presented* the preliminary results of its report on such a design to the Sub-Annual Capacity Market Senior Task Force at its Dec. 12 meeting. Monthly task force meetings are scheduled through June. ■

SPP will Widen Western Foothold in 2026

By Tom Kleckner

SPP has made it official: The operator of the sprawling Midwestern grid *technically* is in the Western Interconnection.

That means it has office space in downtown Denver that includes a sizeable meeting room, a break room and several offices with three workspaces. That allows SPP to boast a "physical presence" in the West, as one staffer said.

In April, it's scheduled to become operational. That's when the grid operator's 14-state footprint will increase by three. Utilities from Arizona, Colorado and Utah will place their facilities under SPP's tariff. It will make the grid operator the first to provide full market services in the U.S. system's two major interconnections, thanks partly to three DC interties totaling 510 MW.

The expansion comes little more than a year after FERC approved an amended tariff that adds the Western members to the RTO and drew praise from several commissioners. Judy Chang said the approval is "another major milestone for the market evolution in the Western part of the U.S." (See *FERC Approves Tariff for SPP RTO West*.)

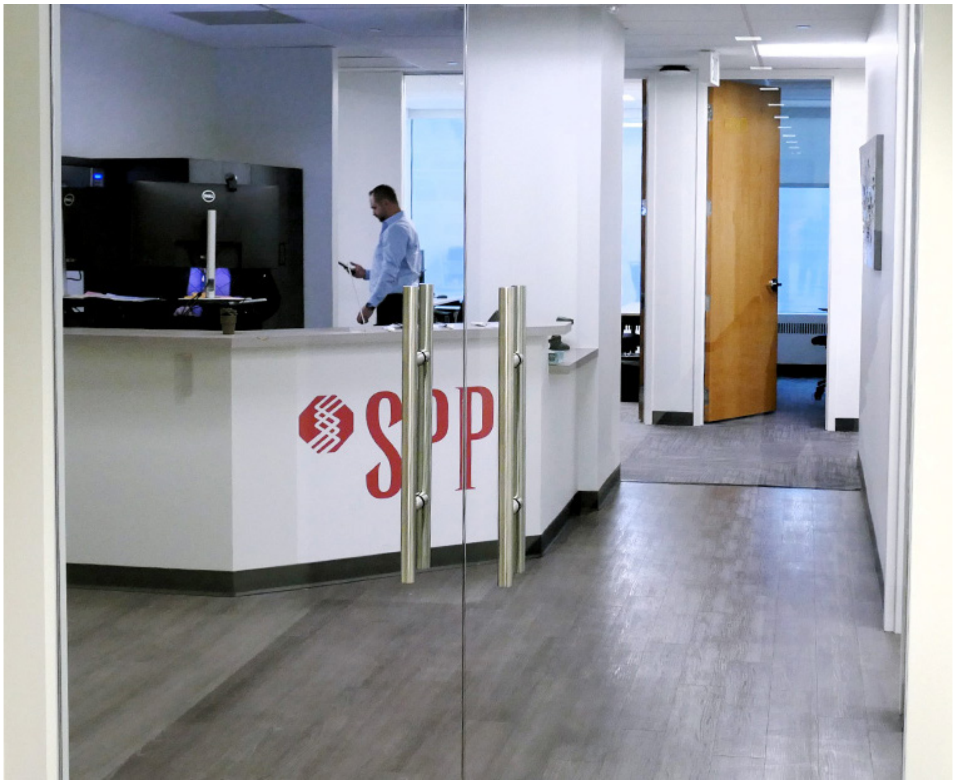
All seven members of *RTO Expansion* — as SPP refers to its new market on the other side of the Rockies — currently participate in SPP's *Western Energy Imbalance Service* (WEIS) market; four of them (Basin Electric Power Cooperative, Municipal Energy Agency of Nebraska, Tri-State Generation and Transmission Association, and the Western Area Power Administration's Upper Great Plains-East Region) are members of the legacy RTO in the East.

A *2022 Brattle Group study* for SPP determined the expansion will produce between \$68 million and \$81 million in annual Westside adjusted production cost benefits and wheeling revenue. Eastside members will see between \$3 million and \$8 million of those benefits.

SPP says it will decide Feb. 2 whether to launch the market April 1 as planned.

"Right now, everything seems to be on track," CEO Lanny Nickell told his board in November." We're looking forward to working with our new members in the West."

The RTO expansion has been somewhat overshadowed by the noise surrounding



SPP's Denver office gives the RTO a physical presence in the West. | © *RTO Insider*

Why This Matters

SPP's RTO footprint will grow to 17 states when it expands into the Western Interconnection in 2026. At the same time, the grid operator is continuing its development of Markets+ for other Western entities.

SPP's Markets+ day-ahead offering, which is providing Western utilities an alternative to CAISO's Extended Day-Ahead Market.

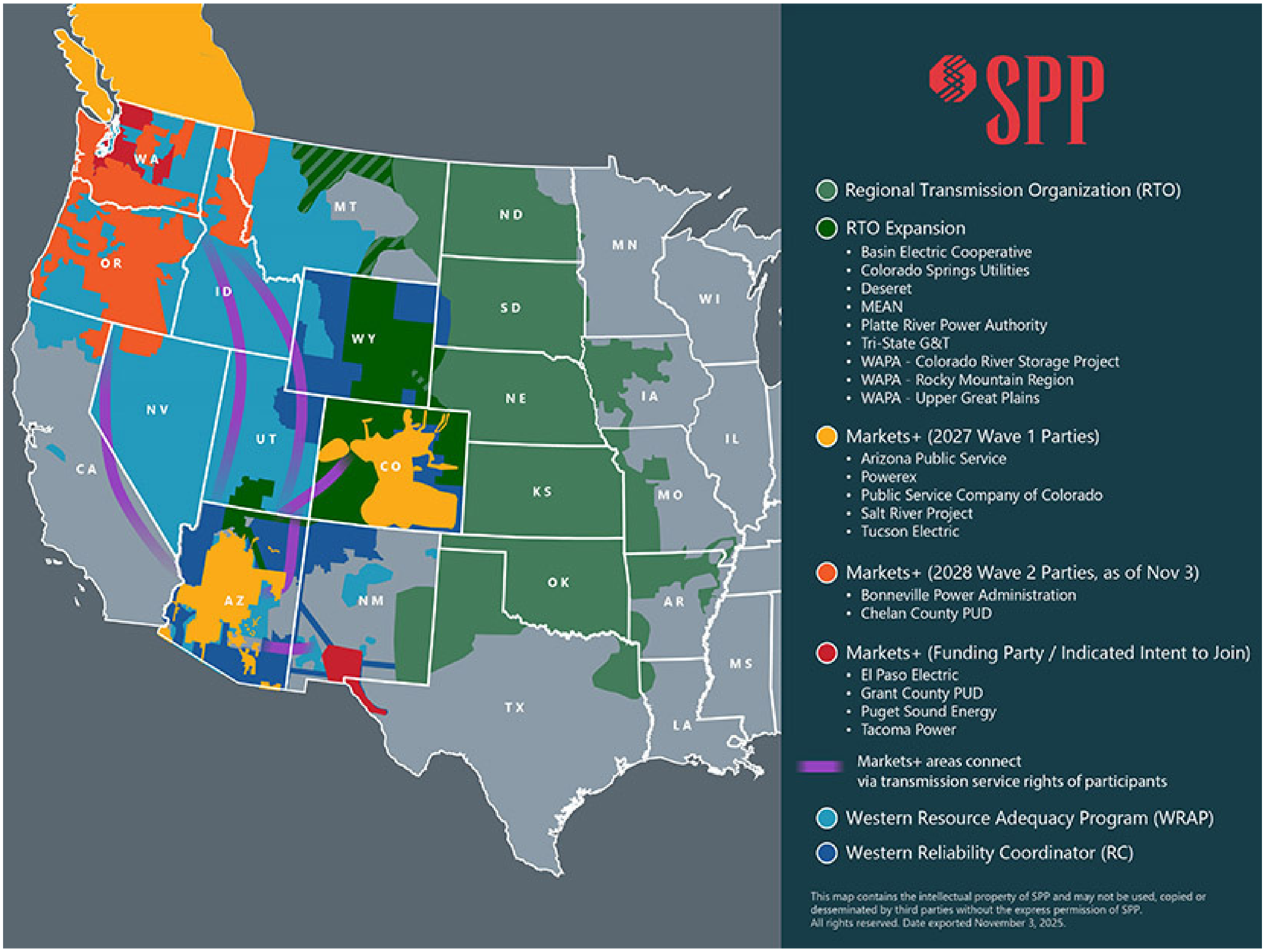
The grid operator's staff and Markets+ stakeholders are well into the initiative's second phase, working together to build the market's operating systems and conduct market trials and parallel operations. SPP says 41 entities have committed to covering the market's \$150 million in development expense; the costs will be recovered through future operations. (See *SPP Markets+ Cruising Through Early Development*.)

Interested market participants have until April 1 to register. They will have about 45 days to complete their registration workbook.

Arizona Public Service, Powerex, Public Service Company of Colorado, Salt River Project (SRP) and Tucson Electric Power are moving forward as balancing authorities. The Bonneville Power Administration will join the secondary market launch in October 2028, along with four other Pacific Northwest BAs.

SPP is targeting October 2027 as the Markets+ go-live date. When the Northwest BAs join in 2028, it will consist primarily of the Pacific Northwest, Desert Southwest and along the Rockies.

The series of complicated seams that will result have caught the attention of FERC, which has asked Western stakeholders to get ahead of seams issues before the markets launch. SPP, experienced in managing seams with MISO, ERCOT and WECC, is hosting a Western Seams Symposium open to western stakeholders at SRP's Tempe, Ariz., headquarters Feb.



SPP's market footprints | *SPP*

26. (See *FERC Report Urges West to Address Looming Market Seams Issues*.)

SPP's Western expansion effort is just one of its three overarching goals. The others are accelerating its generator and large load interconnection processes and mitigating its resource adequacy risk.

The grid operator will begin transitioning in 2026 to its *Consolidated Planning Process*, which combines its transmission planning and GI studies into a three-year process that aligns system modeling, planning assumptions and cost allocation across load and generation needs. The CPP's "ready-to-go" construct replaces the current "request-then-analysis" framework by identifying system needs and costs before the generator asks to connect. (See *SPP 'Blazes Trail' with Consolidated Planning Process*.)

A transition study is underway and will result in a 20-year assessment in November 2026. The 2027 study will sunset the current process and integrate RTOE transmission needs before the first full CPP 10-year assessment in 2028.

The studies will be run in parallel with a strategic partnership announced during the summer between SPP and global tech giant Hitachi. The two organizations are collaborating to accelerate the GI process by reducing study times 80% through end-to-end industrial AI and advanced computing infrastructure. (See *SPP, Hitachi Partner to Use AI in Clearing GI Queue*.)

SPP's two previous planning cycles resulted in more than $16 billion of transmission projects and included five 765-kV lines, the RTO's first. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue* and *SPP Board OKs Updated 2025 Transmission Plan*.)

Several other 765-kV projects were set aside as SPP, like other grid operators, prepares for a future projected to be dominated by data centers, crypto miners and industrial electrification. A more recent Brattle Group study found the RTO will require at least $88 billion and up to $263 billion of generation investment to support load growth through 2050. (See *SPP Study: $88-263B in Generation Needed by 2050*.)

Naturally, affordability is a concern for regulators and other stakeholders. SPP has created the *Cost Control and Allocation Review and Evaluation (CARE) Team*, a cross-functional leadership body to review and recommend refinements or alternatives to the current transmission cost controls and cost-allocation methodologies. The team met once in December 2025 and took a deep dive into SPP's various cost mechanisms; it has set a meeting schedule that lasts into November 2026. ■

Natural Gas Generation in Demand, and Priced Accordingly

Load Growth, Political Support, Abundant Supply Boost Prospects

By John Cropley

With support from the Trump administration and demand from data centers, 2025 and now 2026 are high times for the U.S. natural gas sector.

But the picture is not uniformly rosy: Large gas turbines are hard to come by and increasingly expensive, gas transmission pipelines are constrained in some regions, and rising LNG exports further weld the U.S. market to global price volatility.

Natural gas *accounted for 43.4%* of U.S. utility-scale generation in 2024, more than nuclear (18%) and renewables (17%) combined, according to the U.S. Energy Information Administration. Net generation from natural gas was 3.5% higher in 2024 than 2023, while renewables jumped 12.8% and nuclear held steady.

Renewable energy, particularly solar, is likely to carry this momentum well into President Donald Trump's second term, despite his efforts to boost fossil fuels, but a large pipeline of natural gas projects awaits.

GE Vernova, which claims the title of world's largest gas turbine manufacturer and supplier, said in early December it would end 2025 with a backlog of 80 GW of orders and manufacturing slot reservations — and need until the end of 2028 to fulfill it. The company has been raising its prices as well — CEO Scott Strazik *said in October* that a new combined-cycle gas plant now runs in the range of $2,500/kW of capacity.

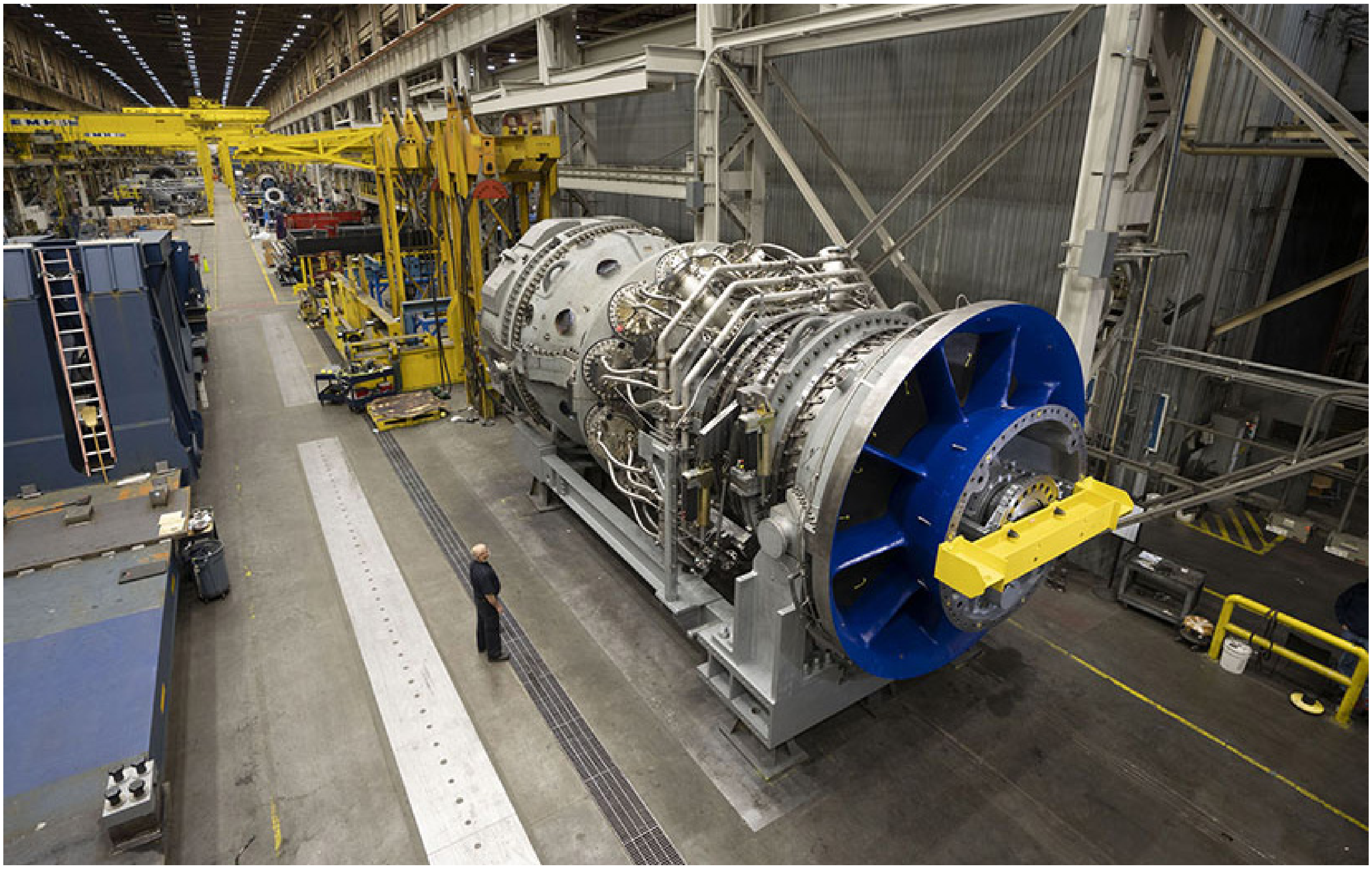
Two large competitors, Siemens Energy and Mitsubishi Heavy Industries, report similarly strong order books.

Why This Matters

Soaring demand for new natural gas generation faces manufacturing backlogs and other constraints.

"We continue to see high demand for gas turbines particularly in the U.S., where new electricity demand from the data center buildout and other factors are driving capital expenditures at our utility customers," Mitsubishi CFO Hiroshi Nishio *said in November*.

Siemens Energy *said in November* it closed its 2025 fiscal year with a $162 billion backlog and with a 43% increase in transactions for its gas services division, which



Manufacturers are reporting yearslong backlogs for heavy-duty gas turbines such as this 7HA.03, shown in GE Vernova's Greenville, S.C., factory. | *GE Vernova* sold 194 gas turbines.

Natural gas-fired generation has had its ups and downs. It replaced coal as the dominant U.S. power generation fuel when advances in hydrofracking techniques made the nation the world's leading natural gas producer.

Federal priorities quickly swung toward renewables under President Joe Biden, then swing back even more suddenly under President Donald Trump.

Natural gas-fired generation capacity will grow, Brattle Group principal Samuel Newell told *RTO Insider*. But that does not necessarily lock the U.S. into decades of use.

"I think the next several years, the demand growth is such that the combination of using the existing gas-fired fleet more and new capacity, we're going to be burning a lot more gas in the next several years," he said. "But in the long run, if we go in a direction that does take climate change seriously, you'd have to increase non-emitting generation a lot, some combination of renewables and nuclear. [But] the gas-fired is still helpful to have there for reliability reasons."

The larger problem is that load forecasts are increasing at a rate that outstrips the supply chain's ability to produce new gas-fired generation, said Newell, who leads more than 50 electricity-focused consultants at Brattle.

"I think we're in a position where it would really help to have everything," he said, which is why he expects wind, solar and storage development to continue despite the policy shifts against wind and solar.

The political shifts are not the only influence on energy-sector strategies, but they can be hard to overlook.

Samuel Newell | *Brattle Group*

National Grid's Northport Power Plant is shown in October 2024. It is one of the aging gas-fired power plants that help keep the lights on in New York. | © *RTO Insider*

Strazik *said in December 2024* that GE Vernova had secured 9 GW of turbine manufacturing reservations just in the month after Election Day.

NextEra Energy *in February 2023* boasted it was the word's largest generator of renewable energy from the wind and sun. *In January 2025*, it emphasized that it had the nation's largest natural gas fleet and recently had struck a framework agreement with GE Vernova to pair new gas generation with renewables and storage.

NextEra's *December 2025* investor presentation contains more than 200 references to "gas" and boasts of being the quintessential all-forms-of-energy company: Gas-fired generation, nuclear, electric transmission, gas pipelines, storage and renewables, in that order. The *December 2023* investor presentation contains only 26 references to "gas," and 16 of those were buried in the fine-print disclaimers at the end.

So what becomes of all this gas generation demand if the major manufacturers cannot quickly meet it?

In some cases, smaller-scale generation is a solution.

Caterpillar, *Cummins*, *Generac*, *Rolls Royce*, *Wartsila* and others all are reporting booming demand for their products as standby or prime power for data centers.

GE Vernova does not operate in this space — its offerings start at around 35 MW.

The company says its 35-MW LM2500 aeroderivative gas turbine will consume about 60% more fuel and emit 60% more carbon dioxide per megawatt hour generated than its 7HA.03 heavy duty combined-cycle gas turbine configured in a 2x1 block, while its 90-MW 7E simple-cycle gas turbine's consumption and emissions are roughly 90% higher.

But a new 7HA.03 is taking about 24 months to reach commercial operation, compared with about six months for the 7E and about six weeks for the LM2500.

Strazik *said in December 2025* that GE Vernova is not losing deals to competitors pitching small generation.

However, he said, there are projects that initially will rely on someone else's reciprocating engine or other small generation as a bridge solution to eventual installation of his company's heavy-duty turbines.

"But I don't really cry in my beer over that because it's enabling the heavy-duty to get done later," Strazik said. ■

Coal's Decline Slows Amid Demand Growth in 2026, Trump's Support

More Power Plant Retirements may be Delayed, but New Build Unlikely

By John Cropley

Don't call it a comeback.

After a long decline in the United States, coal-fired generation is enjoying strong policy support in the second Trump administration.

It has seen an *uptick in output* amid rising power demand and higher natural gas prices. And planned retirements of aging facilities are being delayed in some cases to preserve generation capacity.

But no large coal-burning plant has been built in the U.S. in more than a decade, and most objective observers do not expect any future construction — natural gas plants are more economical and less likely to face policy friction during a future Democratic presidency.

The U.S. Energy Information Administration (EIA) in its December 2025 *Short-Term Energy Outlook* reported that coal provided 16% of U.S. electricity in 2024. It predicted coal would total 17% in 2025, then drop back to 16% in 2026 as the total number of gigawatt hours generated through all technologies increased by 1.7%.

Brattle Group Principal *Samuel Newell* told *RTO Insider* that the business case for new coal generation does not work.

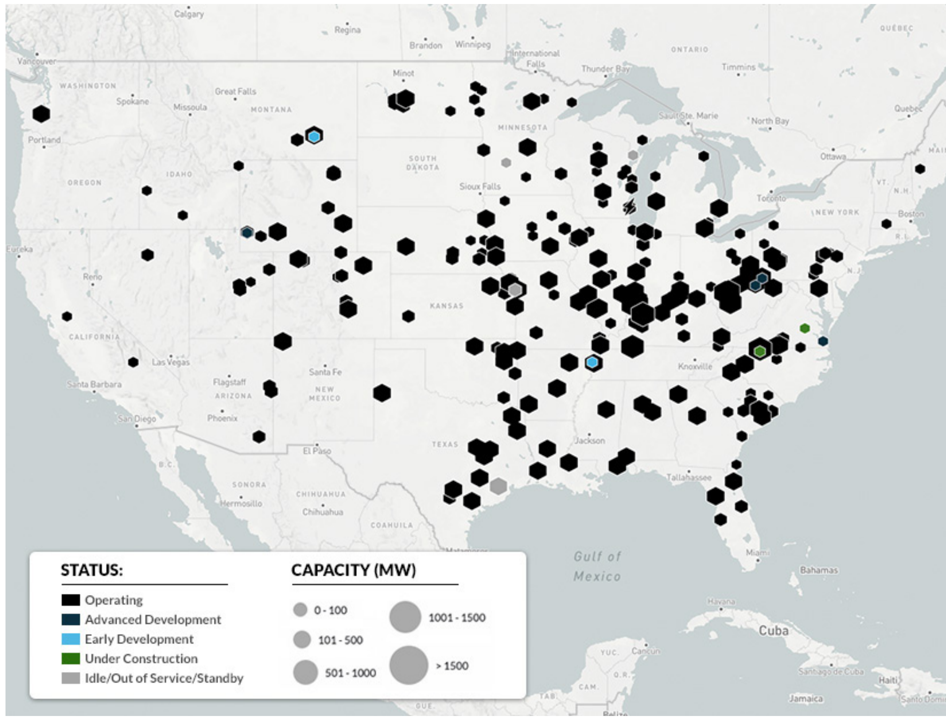
"If you're going to burn fossil, natural gas-fired combined cycle generation is just — you're not going to beat the economics with new coal, even before accounting for the really high exposure to future regulatory risk," he said.

Existing plants are a different matter.

"Certainly, there's a lot of discussion about existing coal and how long it

Why This Matters

Coal-fired generation is risky to build and expensive to operate, even with the Trump administration's support.



The Yes Energy database shows the U.S. coal-fired power generation fleet. | *Yes Energy*

makes sense for existing plants to stay online," said Newell, who leads more than 50 electricity-focused consultants at Brattle. "And there have been many plans, projections for fairly rapid retirement of the coal fleet, but with that likely slowing down a bit with the high load growth we have now. Not new coal."

EIA records show U.S. coal-fired generation declined *in each of the four years* of President Donald Trump's first term, despite Trump declaring his predecessor's war on coal to be over. In his second term, Trump has called for construction of new coal plants, including as co-located power for large loads, but so far, he has had a bigger impact by supporting existing coal facilities.

Trump laid the groundwork for this in April 2025 with an executive order "*Reinvigorating America's Beautiful Clean Coal Industry*," and Energy Secretary Chris Wright has reaffirmed the vision repeatedly since then.

In late May, eight days short of the planned retirement of Consumers Energy's 1,560-MW J.H. Campbell coal plant in Michigan, Wright issued an emergency directive under the seldom-used Section 202(c) of the Federal Power Act to keep it operating, saying it was needed to avoid capacity shortfalls in the Midwest. He subsequently renewed that order twice.

In September, Wright said the Department of Energy is working with utilities around the country to avert other retirements, although he conceded that planned retirements of coal plants that are smaller, older or inefficient are likely to go forward. (See *Wright: DOE Working to Stop More Coal Plants from Retiring*.)

On Dec. 16, Wright *issued a 202(c) order* blocking the imminent retirement of TransAlta Centralia's 730-MW coal-fired generator in Washington, again citing resource adequacy.

And on Dec. 23, Wright issued more emergency orders to keep a pair of Indiana coal plants, F.B. Culley and R.M. Schahfer, running past their previously scheduled retirement at year's end. (See *DOE Orders Two Indiana Coal Plants to Stay Open Through Winter*.)

Some plant operators are pushing back retirements without DOE telling them to do so. Count on Coal *cheered the trend* in an August post, saying more than 40 retirements had been averted in the past three years.

However, coal-fired generation comes with considerations beyond dollars and watts, such as its impact on the climate of the planet and the health of people who live near such facilities.

Alexander Heil, a senior economist with The Conference Board whose work centers on renewables and the energy transition, cited this impact in arguing against coal.

"There's no such thing as clean coal … that's a total misnomer," he told *RTO Insider*. "I mean, there are 9 million people worldwide, I believe, that die every year from air pollution, particulate matter and such. That's not priced … there's tons of social costs, all kinds of externalities with coal."

He added: "I don't really think people are seriously going to be considering coal as an alternative here in the U.S."

Environmental advocates have blasted the J.H. Campbell and Centralia orders, saying they are costly, dirty and unnecessary, as well as a liability, given their age and condition.

"Actions by the Trump administration to force jalopy coal plants to continue burning coal are an unprecedented power grab that cost communities in their wallets and their health," Earthjustice said.

But coal still has its fans.

America's Power, a trade organization advocating for coal-fired generation, says coal is "*critical to maintaining* affordable electricity prices, and a reliable and resilient electricity grid." The organization notes the U.S. has the *largest coal reserves* in the world — enough for 440 years at current production and consumption levels.

America's Power recently commissioned *a study that concluded* the cost of replacing U.S. coal with various configurations of renewables and other generation would run $3 billion to $54 billion a year, plus unquantified loss of reliability attributes.

"Fortunately for consumers, utilities in 19 states have reversed decisions to retire coal plants, but more than 50,000 MW of coal generation are still scheduled to retire over the next five years," CEO Michelle Bloodworth said as she *announced the report* Dec. 10. "This amount of coal generation could power at least 50 hyperscale data centers, which are in desperate need of power. The new study shows that it would be a big economic mistake to allow these coal retirements to continue."

Alexander Heil, The Conference Board | *The Conference Board*

DTE Energy's coal-fired Trenton Channel Power Plant in Michigan is shown before demolition in June 2024. | *Shutterstock*

But the other side offers cost estimates that go in the opposite direction.

The *Environmental Defense Fund said* a study it and other advocates commissioned showed the federal stop-retirement orders could cost ratepayers *$3 billion to $6 billion* a year. (See *New Report: Consumers Could Pay $3B More Annually if DOE Stay-open Orders Persist*.)

EIA statistics quantify coal's decline:

- *U.S. coal production* has come nearly full circle in the past 75 years, rising from 481 million short tons in 1949 to 1.17 billion in 2008 and *dropping* to 513 million in 2024.
- From 2015 through 2024, U.S. *coal-fired generation* dropped from 1,352 TWh to 652 TWh per year, with every year but one lower than the year before.
- Natural gas generation increased 40% from 2015 through 2024 and surpassed coal as the leading U.S. generation technology in 2016. (Solar generation by comparison jumped 678% over the same period but still provided only 47% as much electricity as coal in 2024.)
- The number of U.S. coal-fired plants dropped from 491 in 2014 to *219 in 2024*.
- From 2015 through 2024, the time-adjusted capacity of the U.S. coal fleet dropped from 286 GW to 176 GW, and *its capacity factor* fell from 54.3% to 42.6%. ■

Solar Power Continues to Make Gains, but Slowdown Expected in 2026

Huge Momentum Developed in Biden Years Likely to Diminish Under Trump 2.0

By John Cropley

Photovoltaic solar is expected once again to account for a significant percentage of U.S. generation capacity additions in 2026, even as the number of gigawatts being installed decreases from record highs in 2023 and 2024.

The degree of risk and uncertainty springing from indifferent or outright obstructive new federal policies in 2025 has trimmed planned solar deployment, but not "bigly," because the central argument for solar endures for now: It is a relatively quick and cheap way to add emissions-free electrons to a grid that sorely needs more electrons.

"We've seen a tremendous decrease in the levelized cost of solar, though that has slowed in recent years, given a lot of the supply chain and tariff effects that are out there," said *John Hensley*, senior vice president of markets and policy analysis for the American Clean Power Association. "But solar in many of these markets is the least-cost new-build resource. And in some cases, you pair that with storage, which is a fairly cost-effective strategy, and that combo pack just looks very enticing in a lot of these markets."

Why This Matters

Solar power was the largest addition to the U.S. grid in 2025 and remains important despite President Trump's attempts to marginalize it.

Solar has another advantage: Alternatives are limited.

No one is likely to build new coal or large conventional hydro generation; new nuclear is coming but not for several years; and new natural gas turbines are expensive and backlogged for a few years.

New deployment of wind power has slowed to the point that solar is poised to surpass it as the largest U.S. renewable resource by nameplate capacity.

Countering these factors is President Donald Trump. While he does not express the same hostility for solar panels as for wind turbines, he does treat solar like a rival to fossil fuels and is moving to limit solar through policy restrictions, tariffs and elimination of tax credits.


A large solar array near Austin, Texas | *Shutterstock*

What new surprises the Trump administration holds for solar and other renewables in the new year can only be guessed.

But so far, the effect has been significant if not severe. BloombergNEF in November lowered its 2025-2035 projection of solar capacity additions by 25% but still expects to see 432 GW of new utility-scale solar.

The Solar Energy Industries Association and Wood Mackenzie in December *maintained their projection* of 250 GW of solar installations from 2025 through 2030, with the caveat that significant uncertainty hangs over the industry and its future.

The U.S. solar industry has the potential to build more than 250 GW, WoodMac added.

In February 2025, well before the One Big Beautiful Bill Act codified an early end to federal tax credits for solar and wind projects, the Brattle Group looked at the possible outcome of eliminating or altering clean energy credits in a *report* commissioned by *ConservAmerica*. It concluded solar additions through 2035 would drop from 550 GW to 242 GW.

Samuel Newell, who leads more than 50 electricity-focused consultants at Brattle and was a co-author of the report, told *RTO Insider* that solar will continue to see growth, though not unbridled.

"Solar is absolutely a proven technology and continuing, even still, to improve, and so we'll still see more of it," he said. "I think the headwinds are there too. There is community opposition. There is the cost relative to gas-fired [generation] in a world that's not paying for its emissions, and it also has the challenge that … in terms of meeting resource adequacy needs, it has lower and lower marginal value the more you add, and even lower energy value the more you add."

The drop-off is a few years away, Newell predicted.

With "wind and solar, there's obviously a rush to build the plants currently far enough along to be able to meet the safe harbor to still get the tax credits," he said. "After that, I would expect them to fall off quite a bit. Some states will still build them where they're economic because there's such good wind and solar resources. They won't build as many as they would have if there had been the tax credits."

Alexander Heil, a senior economist with The Conference Board whose work centers on renewables and the energy transition, said the numbers still support solar even if policy does not.

"If you look at some of the data, solar and storage is now cheaper than natural gas when it comes to electricity generation," he said. "So I think it's probably a question of how much that transition is going to slow in the U.S., [rather than] completely turn around."

Heil added the caveats that economics and solar resources are far from equal from one region of the country to the next.

(One example: The Energy Information Administration reported that 2023 *capacity-weighted average cost* of new solar construction in the Northeast was $2,584/kW — 61 to 67% higher than in the South, West and Midwest. It also reported that *solar capacity factors* in the Northeast states are lower or much lower than in those other regions of the country.)

Coal *produced 196% more U.S. electricity* and natural gas produced 750% more than utility-scale solar panels in the last year of Joe Biden's presidency. Plenty of people and interest groups would like to raise those percentages even higher, and they have the ear of policymakers in the first year of Trump's second presidency.

SEIA in November issued a report warning that more than 500 solar and storage projects totaling 117 GW of capacity are *threatened by political attacks*. On Dec. 4, it *sent Congress a letter* signed by 143 solar companies asking it to get the Department of the Interior moving again on permitting solar projects. A near-total moratorium had been in place since an *Interior memo* in July that revised the review procedures, they complained.

That memo was a masterwork of byzantine bureaucracy and analysis paralysis. ACP and many other clean energy advocates called it an *intentional effort* to slow renewables. It specifies separate reviews by two high-ranking Interior officials of a 68-point checklist for wind and solar facilities on public land and then a third review by the Interior secretary himself. The 69th point is a catchall for anything not included in the first 68 points.

Illuminate USA employees mark production of the 1 millionth solar panel at the company's factory in Ohio. | *Illuminate USA*

The policy extends beyond public land to include anything on private land that needs a permit from the Interior, requires the department to sign off on another agency's permit or uses its resources.

Two weeks after the SEIA protest letter, *Interior signed off* on a *700-MW solar project* proposed in western Nevada.

Whether or not this was an actual or *de facto* moratorium, the takeaway is the same: The momentum the U.S. solar industry carries into 2026 is shadowed by uncertainty and risk.

"I think there's a number of officials who look at executive orders and some of the action by Interior or other parts of the administration, and the gut thinking is that, 'Oh, this only affects projects that are on public lands or in public waters,'" Hensley said. "But when you read deeper into those documents … you realize it affects more."

All this comes after considerable effort and expense to establish a U.S. photovoltaic manufacturing base — something that would mesh well with Trump's stated priorities if it did not involve renewable energy.

Sixty-five solar and storage manufacturing facilities began or expanded production in the first three quarters of 2025, SEIA said, including an ingot and wafer factory that *completed the supply chain*. Every major component of a solar farm now can be sourced from U.S. factories.

Just in those nine months, U.S. solar cell production capacity more than tripled, and it has increased more since then.

"We've seen tremendous advancements in the development of solar and battery module manufacturing facilities, increasing focus and intent on bringing the cell manufacturing lines here to the U.S.," Hensley said. "We don't want to lose sight of that. It's not just about bringing electrons to the system; there's a lot of job creation and economic growth activity that's going on in the manufacturing space as well, and it's happening fast."

ACP tallied 146.2 GW of utility-scale solar generation nationwide at the end of the third quarter of 2025, nearly half of which came online after 2022. *EIA reported* that solar was expected to account for more than half of all new U.S. generating capacity coming online in 2025. ■

Trump Scoring Victories as he Goes Tilting at Wind Turbines

Restrictions and Perceived Risk Crimp Wind Power Development on Land and at Sea

By John Cropley

As 2025 opened, there was no uncertainty surrounding Donald Trump's opinion of the wind power industry. The question was how soon the opinion would turn to action and how damaging it would be.

The answer: "immediate and significant."

As 2026 opens, we have a clearer view: Every onshore wind project that falls within federal purview is delayed, and the U.S. offshore wind pipeline is a shadow of its former self, reeling from a blanket stop-work order on all remaining projects in late December. (See *All U.S. Offshore Wind Construction Halted*.)

Onshore wind is an established sector of the U.S. energy market, unlike offshore wind, and seems better able to ride out the hostile policy changes of Trump 2.0. Land-based wind turbines for years have been the leading U.S. source of renewable energy. The pace of construction slowed in recent years, and photovoltaic solar was poised to surpass it as the leader in installed renewable capacity.

But with its higher capacity factor, wind still produces far more electricity: 451,904 GWh, compared to 219,834 GWh from utility-scale solar arrays in 2024, according to the *U.S. Energy Information Administration*.

This compares with 232,896 GWh from conventional hydropower, 652,156 GWh from coal combustion, 718,865 GWh from nuclear reactors and 1,869,892 GWh from natural gas combustion.

Why This Matters

Wind power is an important part of the U.S. power portfolio, producing as much electricity in 2024 as hydroelectric and utility-scale solar generation combined.


Crews in Portsmouth, Va., load monopile foundations for Dominion's Energy's Coastal Virginia Offshore Wind, which would be the largest wind farm in U.S. waters. | *Dominion Energy*

John Hensley, senior vice president of markets and policy analysis at the American Clean Power Association, said U.S. onshore wind experienced a marked regulatory slowdown in 2025. The restrictions on wind and solar projects on public land included multilayered review processes that extend to projects on private land for things such as incidental eagle take permits and U.S. Army Corps of Engineers permits. Approvals essentially halted as a result.

"To date, we have not heard of any [wind] project that's actually received any approval to move forward," Hensley told *RTO Insider*.

The slowdown for onshore wind in the early 2020s came despite the Biden administration's support for renewables and has several underlying factors, Hensley said.

The extensive buildout from 2005 to 2020 saturated some markets; filled up some of the prime locations; and left utilities and large offtakers wanting some diversity in their generation mix.

Solar construction took off synergistically: Solar typically is strongest at midday, when onshore wind often is weakest, and interest was growing in renewables in regions with good solar irradiance but weak wind speeds, including the Southeast and Mid-Atlantic.

Importantly, the cost of solar components plummeted, Hensley said.

As a result of all this, installed capacity grew 90.5% for solar and just 8.3% for wind from the *first quarter of 2023* to the *third quarter of 2025*, by ACP's count.

But there was a rebound for onshore wind in 2025, which ACP expects will end with 36% more additions than in 2024.

There is more to come in 2026 and beyond, Hensley said, reiterating what ACP and other clean energy advocates have been saying for the past year: The U.S. demand for electrons is too great to sideline the fastest, least-expensive source of new generation — solar and wind — at a time when gas turbine orders are backlogged for years, no one is building coal or large conventional hydro, and new nuclear will not come online until the 2030s at best.

In their *fourth-quarter wind report*, ACP and Wood Mackenzie predict 46 GW of new wind installations through 2029, plus 2.5 GW of capacity additions via upgrades through 2028, thanks to a *strong repowering market*.

BloombergNEF, meanwhile, has reduced its 2025-2035 U.S. onshore wind projection by 46% but still expects 74 GW of new capacity in that period.

"We're in this interesting moment in the market where, because of a lot of the electricity growth that we're seeing and the resource adequacy concerns that a lot of these markets are showing, there's just a voracious appetite for new power plants across the entire technology stack," Hensley said.

The demand exists for additional onshore wind, and the industry can meet it, he added, but this is subject to external influence.

"I think it becomes a question of how long [the hostile policies] stay in place, and how much of the project pipeline is impacted," Hensley said. "Even though wind has been growing slower than solar and storage, it is still a very large and mature industry in the U.S., with a substantial manufacturing base."

He conceded that a large enough regulatory burden and high enough costs could slow the onshore wind industry.

Just look at offshore wind.

Whatever chance the industry had of meeting President Joe Biden's aspirational 2030 goal of 30 GW of wind capacity in U.S. waters was gone well before Trump was elected to his second term, because of cost, logistical and other factors.

But 2025 saw a series of policy crackdowns by the Trump administration aimed at fulfilling his campaign promise to block offshore wind development. Amid this, a series of developers put their projects on hold or quit the U.S. market altogether.

There were a few bright spots. In September, a federal judge threw out a stop-work order the Department of the Interior slapped on Revolution Wind. In early December, a different federal judge threw out Trump's Day 1 pause on wind power permits in a case brought by the attorneys general of New York and 17 other states.

The Alliance for Clean Energy New York joined that lawsuit as a plaintiff intervenor. Alicia Gené Artessa, director of ACE NY's New York Offshore Wind Alliance (NYOWA), told *RTO insider* a week later that the ruling was a sign of hope for the offshore wind industry in its battles with Trump, providing a foothold for states and the industry to take the federal government to court over permit denials.

That conversation was a week before Interior ordered a halt to all U.S. offshore wind construction activity — five projects with 5.5 GW of combined nameplate capacity costing tens of billions of dollars, some of them very close to completion.

The latest stop-work order is a dramatic escalation of Trump's war on wind. As of press time, the order's full impacts are still unclear, and the next steps by the government and industry has not been announced.

But Gené Artessa's takeaway message on the offshore wind sector is relevant regardless of the blow-by-blow with Trump and its ultimate outcome: The industry and its partners in state government need to fix the problems that afflicted U.S. offshore wind before Trump returned to office, and they need to prepare for the next tranche of projects to follow his departure from office — particularly in a state like New York, which is counting on offshore wind to decarbonize its grid.

"That's one thing that I think the state recognizes, we have to protect this industry," Gené Artessa said. "So to get through the next few years of federal hostility, we need to look inward, because we had attrition before Trump took office. We had issues with our procurement process that needed to be solved. That's what we are hyper-focused on for 2026."

The Trump administration already has scared away investors critical to future offshore wind projects in U.S. waters. The question remains whether they will come back during the future administration of a wind-friendly president, because even the fastest project could extend beyond a single four-year presidential term.

Gené Artessa acknowledged that some developers will quit the U.S. offshore wind market and others will struggle mightily, which she said directly contradicts Trump's stated desire to boost jobs and increase power generation. But there is the opportunity to fight back in court, she said, and the opportunity for states to improve their own processes.

"To me, it doesn't make any sense," she said, "but we are alive for another day, and we're keeping the good fight going over here at NYOWA." ■

NextEra Energy Resources' Callahan Divide wind farm in Texas | *NextEra Energy Resources*

Nuclear Power Retains Great Potential in 2026

Analysts Say Meaningful Capacity Increases Still Years in the Future

By John Cropley

Commercial nuclear energy begins 2026 with strong momentum toward future expansion in the United States — "future" being the key word.

Restarts and uprates of existing nuclear plants notwithstanding, it will be years before new-build capacity comes online and possibly a decade or more before a significant amount of new gigawatts is added to the grid.

But 2025 was marked by a continual stream of announcements of technological advances and new offtake agreements for the power to be produced by future reactors employing those new technologies.

President Donald Trump jumped in with both feet as well, ordering regulatory streamlining to get new reactors built faster and setting aspirational goals for a nuclear generation buildout the likes of which the world has never seen.

The limited amount of nuclear construction attempted in the U.S. over the past three decades has been a train wreck of delays and cost overruns, but that has been due in no small measure to how few civilian reactors were being built in this country.

The expectation and hope now is that enough new reactors will be built that economies of scale and standardization can develop, bringing the levelized cost of nuclear power down to a point where it is a viable option for helping meet the expected surge in demand for electricity.

And there is even some hope of harnessing a unicorn that has eluded so many scientists and engineers for so long: commercially viable fusion power.

The Bottom Line

Although there have been significant signs of progress for new nuclear power heading into 2026, it also faces a long timeline and plenty of potential obstacles.

Georgia Power's Plant Vogtle Units 3 and 4 are shown in March 2024. Construction of these reactors cost far more money and took much more time than expected to build. | *Georgia Power*

But much progress still needs to be made, particularly with the first wave of small modular reactors (SMRs) that are not merely next-generation versions of the large light-water reactors that make up the present-day U.S. fleet.

"2026 is too early for things to fully come to fruition," said utility consultant Yavuz Arik of energytools. "I mean, we have still a long way to go to deployment of some of the new SMR technologies."

But Arik said progress will be steady and significant in 2026.

"I think President Trump has set a lot of interesting things, great movements, in place. The regulatory oversight part has been expedited now. In my opinion, that doesn't mean that we're foregoing safety."

He agrees with the urgency Trump has attached to new nuclear.

"Right now, we have a national priority that we need power and we need clean power. We can go dig for more coal and gas, but we need to get ahead of the curve, and we're running behind both the Chinese and the Russians in many ways."

Exhibit A in any discussion of slow and expensive nuclear construction is the expansion of Plant Vogtle in Georgia, but what often is overshadowed by the stunning price tag is the fact the project was in some ways a first of a kind, which almost always is more complicated and/or expensive than follow-up efforts.

Brattle Group principal Samuel Newell said the potential exists for the U.S. to move forward from Vogtle at lower cost and higher speed with subsequent projects using the same Westinghouse AP1000 reactor, eventually reaching Nth of a kind speed and economy.

"You can build on what we learned from Vogtle with an AP1000," he said. "That has basically a complete design that now would be done before starting construction, which was one of the problems with Vogtle. We know how those plants work; there's very little risk that it wouldn't operate. … So we're a little further along with that."

Next-generation SMRs present a different set of issues. Designs such as the GE Vernova Hitachi BWRX-300 — the first SMR being deployed in North America —

The manufacturing team surrounds a toroidal magnet in the testing chamber at Commonwealth Fusion Systems, a leading company in the chase to develop commercially viable nuclear fusion power. | *Commonwealth Fusion Systems*

are smaller, more advanced versions of large-scale boiling water reactors. This could reduce the number of "first of a kind" factors.

But other SMR designs are starting with more unknowns and greater risks.

"They have even less developed supply chains, and really less developed supply chains for fuel," Newell said, but added that he's optimistic some of the dozens of SMR designs being pursued will reach widespread adoption.

"I hope this country pursues several of them and learns if some of them eventually make the most sense," said Newell, who leads more than 50 electricity-focused consultants at Brattle. "But even if we do, Nth of a kind would still be the 2040s before we have them at any really substantial scale."

Alexander Heil, a senior economist with The Conference Board, said there is some urgency to the effort: The existing fleet is decades old. The wave of retirements of functional but not economic reactors has halted, and the Nuclear Regulatory Commission signed off repeatedly in 2025 on extensions of operating licenses, but nothing lasts forever.

"On average they're 40 years old," Heil said. "You can probably stretch into 60 in terms of permit and design life. But that also means we do the math on this stuff, that in the next generation, without any serious additions, the U.S. is going to be out of the nuclear business. What currently still makes up 20% of the grid is going to be rapidly declining."

Heil believes in the statistical safety of nuclear power, even having lived through a three-month stay-at-home order after the Chernobyl disaster. What concerns him more is the prospect of hundreds of new nuclear waste dumps around a nation that lacks a central repository for material that will remain dangerous for millennia to come.

Heil also is skeptical that nuclear generation will reach a point of speedy and economical construction and achieve a true renaissance.

"I just don't see, in practical terms, how this is really going to happen at the scale that we would want this to happen if it's supposed to be replacing what's currently on the grid," he said.

The "modular" in "small modular reactor" is the reason why many people are pinning such high expectations on SMRs: If they can be constructed on-site in serial fashion, or even factory-built and shipped to the site in containers, they should be able to achieve great economy of scale.

That does not address other potential stumbling blocks facing SMRs, notably fuel supply, but it should help reduce the cost and increase the speed of nuclear buildout.

But which SMRs?

The third edition of the Nuclear Energy Agency's SMR Dashboard in July analyzed 74 SMR designs; 27 of the companies behind them are headquartered in the U.S. — more than in the next four countries combined.

Arik flagged X-energy's Xe-100 design as one to watch in the crowded landscape. Along with electricity, it can produce industrial heat, and it has a high burn-up fuel cycle with less waste generated than earlier technologies.

"It's probably going to go maybe 700 Celsius," he said. "When you go that high, you can do a lot of industrial use heat as heat, and that provides a big advantage, too, because you're not converting heat to electricity and then using electricity, you're using heat as heat. And for X-energy's design, it's an 80-MW electric but 200-MW heat for each reactor."

X-energy in November announced the start of above-ground construction of the nation's first advanced nuclear fuel fabrication facility. The company is pursuing construction of a four-reactor complex that will provide electricity and industrial steam to a Dow plant in Texas and up to a dozen reactors in Washington state through an agreement with Amazon, an investor in X-energy.

Arik also is watching TerraPower. At 345 MW, its Natrium reactor is too big to meet the classic definition of an SMR — 300 MW or less per unit.

It instead is a small advanced reactor. It is sodium-cooled, which Arik noted has been proved to work, and it doubles as energy storage: The molten salt can provide gigawatt-scale backup to grids with a high percentage of intermittent renewable generation.

In March 2024, TerraPower was the first developer to submit a construction permit application for a commercial advanced reactor to the NRC. Later that year, it began site work for a Natrium demonstration project in Wyoming.

NRC in December 2025 completed its safety review, concluding there were no safety concerns that would preclude issuance of the construction permit. Further deliberations and review are needed, but NRC is trying to expedite such processes.

Arik expects it to come together.

"Now, there have been trials when you try to do [sodium cooling] bigger and bigger, then you get into different problems," he said. "But TerraPower is trying to do it at this right size, this 345 MW, which I think they're going to succeed at."

Then comes the important part, not just for TerraPower and X-energy but the nuclear industry as a whole: Getting the first of a kind built, fine-tuning it and moving toward Nth of a kind.

"Once we get to mass production, we're going to be able to turn out things much, much faster, and the U.S. is great at that," Arik said. "So, I'm confident that things are going to get really faster, like we're going to wrap this up within three years, once that design is set in stone." ■

Advanced nuclear technology company Oklo holds a groundbreaking ceremony for its first Aurora powerhouse at Idaho National Laboratory in September 2025. | *Oklo*

Prospects for Growth, Threat of Contraction Face Hydropower in 2026

Potential New Capacity Countered by Impending Expiration of Existing Licenses

By John Cropley

The U.S. hydroelectric sector is approaching a bit of an inflection point as 2026 begins: The demand for energy storage capacity is driving a flurry of proposals for new pumped storage hydropower (PSH) capacity, but proposals for new conventional hydro facilities are limited to small-scale projects.

Moreover, much of the U.S. conventional fleet is aging, and many operators must decide whether to begin the often-long and potentially costly federal relicensing process.

The kinetic energy of moving water has been harnessed for so many centuries and is so integrated into the landscape that it can be easy for people outside the electric industry to forget it is there.

But nationwide as of 2024, there were 2,250 conventional plants rated at a combined 80.6 GW and 42 PSH facilities rated at 22.2 GW, the Oak Ridge National Laboratory reported September in its *2025 Market Update*. These accounted for 5.9% of all U.S. power generation and 27.4% of U.S. renewable electricity generation.

Just as important in the era of intermittent generation, hydro offers the grid a dispatchable backstop when demand spikes up or supply spikes down. The National Hydropower Association (NHA) calculates hydro accounts for about 40% of the U.S. black-start capacity.

But there is no new Hoover Dam or Niagara Power Project on the drawing board, nor is there likely to be, NHA President Malcolm Woolf told *RTO Insider*.

"We're not building those kind of massive hydropower facilities anymore," he said. "The real challenge is, how do we not go backwards? How do we not lose that critical infrastructure?"

NHA's dashboard provides the context for his point: In most years from 2003 to 2021, no more than five federal licenses expired, and in several years, none did. In the next three years combined, 120 expired. 2025 saw 20 expirations, and 59 licenses will expire in 2026. After a relative lull with 20 to 30 expirations per year, 301 licenses will expire from 2033 through 2037.

"We've got, I believe, 16,000 or 17,000 MW that are up for relicensing in the next decade, and it often takes a decade or longer to relicense these facilities," Woolf said.

"So I do think that, frankly, this administration, the remaining three years are going to be decisive, because these facilities are going to have to make a decision now on whether they want to go through the lengthy and expensive relicensing process, or whether they want to just run their facility until their existing license ends, and then turn off the powerhouse."

Water flows through the spillways at Chief Joseph Dam in Washington, the largest hydroelectric dam operated by the U.S. Army Corps of Engineers. | *U.S. Army Corps of Engineers*

Why This Matters

The U.S. hydropower sector is approaching an inflection point as increasingly large numbers of facilities near the end of their federal licenses.

Individual dams may be controversial, but as a whole, the hydro sector enjoys bipartisan support, Woolf said.

Hydropower is one of the Trump administration's *preferred technologies* as it pursues a "*Golden Era of American Energy Dominance*"; the One Big Beautiful Bill Act preserved enhanced tax credits for repowering existing hydro facilities even as it pinched the other major renewables, wind and solar.

But what the hydro industry still is waiting for, Woolf said, is streamlined permitting. Not knowing how long licensing will take or how the costs will change over that period is a barrier to investment.

"So we are working with this administration, both legislatively and regulatorily, to try to streamline the regulations — not cut out state agencies or others, but just try to create some process discipline, so that if everyone's going to need to do their own NEPA review, how about you do the NEPA reviews all at once, instead of four different times in series?"

The tax credits and greater clarity on licensing or relicensing would help revitalize the industry, Woolf said, but there are other speed bumps.

There is not, for example, much of a domestic manufacturing base for hydropower equipment — few facilities have been built in recent decades, and those that exist tend to last for decades, so the demand does not exist to support a supply chain. Imported gear could face supply chain constraints or tariff costs.

There also is the unknown impact of climate change on the precipitation that conventional hydro relies on.

The Energy Information Administration reports wind and solar generation increasing in 19 of the past 20 years as installed capacity increases but shows hydro up and down from one year to the next, often significantly, despite minimal changes in installed capacity.

The 242 TWh net generation of the U.S. hydro fleet in 2024 was the least in 20 years.

But infrastructure can be adjusted to match changing precipitation patters, Woolf said: "As we're adapting to climate change, we may need more reservoirs, more dams, and then hydropower is a great way to offset the costs of those facilities."

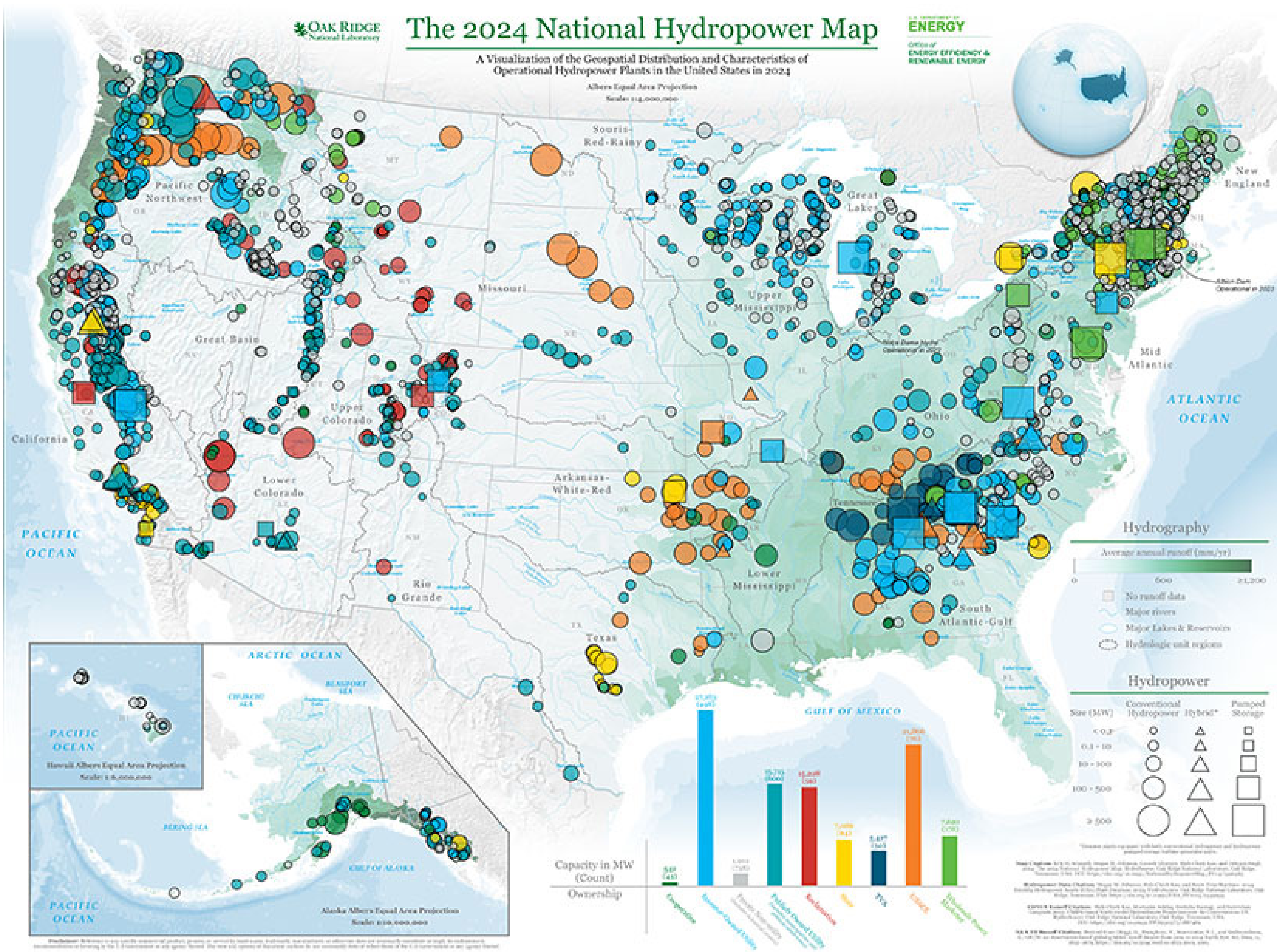
A hydro sector snapshot drawn from the 2025 Market Update:

- There were 78 non-powered dams, 23 conduits and eight new stream-reach development projects in various stages of the development pipeline in 2024, with a combined capacity of 1.12 GW.
- Seventy PSH projects were in the development pipeline in 2024, with a combined storage power capacity of 60.6 GW; additions of 2.5 GW to existing facilities were in the planning or construction stages.
- As of June 9, 2025, 211 conventional hydropower and PSH projects were in the relicensing process and 33 conventional projects were in the license surrender process.
- Economic infeasibility or restoration of aquatic ecosystems are the most often cited reasons for surrendering a license.

Woolf is excited about the prospects for PSH. He said there is the desire to get things built fast, which points to battery storage rather than PSH, which is a conundrum for the hydro industry to overcome. But he also sees a national shift in thinking that favors long-duration assets such as hydropower.

A significant percentage of those 70 PSH proposals in the FERC pipeline will never reach construction, Woolf said, for the same reasons many proposals for other generation technologies will die in the interconnection queue.

"So I'm not suggesting we're going to get 60 GW built, but we haven't built any for 25 years in this country," he said. "But something seems to have changed. It does seem like there's a whole lot more need for long-duration, eight-plus hours of energy storage to back up and firm up increasing variable generation on the grid. Pumped storage is really an established technology that's really perfect for this moment." ■



The U.S. hydropower fleet is mapped as it existed in 2024. | *Oak Ridge National Laboratory*

NERC Navigates Turbulent Reliability Landscape in 2026

ERO Managers Aim for Improvements in Cybersecurity, Assessments

By Holden Mann

As 2025 dawned, the way ahead for NERC's management seemed clear.

The ERO's most recent three-year plan was set to expire in December, and NERC was set to develop a new one to begin in 2026 and carry the organization through 2028. But as the planning process got underway, ERO leaders began to realize the challenge they faced.

NERC was wrapping up the Interregional Transfer Capability Study, an unprecedented continent-wide examination of the transmission system with the potential to change how the ERO conducted reliability assessments. The second Trump administration had sowed major confusion about trade policy and other issues. The ERO's Board of Trustees kicked off a review of the standards development process that wouldn't be finished until February 2026. Multiple issues appeared to be in flux, a difficult environment for long-term plans.

With all this uncertainty in mind, NERC management decided that following through with the original goal would be "a fool's mission," as CEO Jim Robb told stakeholders in a May 21 webinar. (See *2026 to be 'Bridge Year' for NERC Budget*.)

Instead, Robb and other executives agreed to treat 2026 as "a bridge year" in NERC's budget and come back a year later to create a new three-year plan that would guide the ERO from 2027-2029.

Looking back on this decision near the end of 2025, Robb said he still believed it was the right call. The delay allowed NERC to get "a little bit more clarity on how we can make the most important difference possible" in the challenges facing the reliability landscape.

"We were just very early in our exploration of [large loads]. We've got a much clearer view now than we did a year ago," Robb said. "Reliability assessments, same thing. … Gas-electric [coordination], I think we're seeing a lot more progress than we would have guessed a year ago. So while there's still a lot of uncertainty in the environment, I think a lot of it has resolved well enough for us to do a more thoughtful plan than we would have put in place [this] year."

Why This Matters

NERC's managers expect the electric grid to face a litany of challenges in the coming year, including escalating cybersecurity threats, ongoing resource mix changes and a polarized political climate. They say the ERO's technical competence and reputation for independence will be key to addressing the evolving risk landscape.

Cybersecurity Remains a Major Concern

In conversations with *ERO Insider*, Robb and other NERC managers described the organization as well-positioned to meet the year ahead, having overcome the uncertainty that characterized early 2025. One source of that ambiguity was the presidential transition, which left many crucial posts in government open — including the director of the Department of Homeland Security's Cybersecurity and Infrastructure Security Agency.

Nearly a year after the inauguration, CISA still lacks a Senate-confirmed head. The agency has been led by Deputy Director Madhu Gottumukkala since his appointment in May 2025. President Donald Trump nominated Sean Plankey, formerly of the Department of Energy's Office of Cybersecurity, Energy Security and Emergency Response, to head the agency shortly after taking office, but his nomination has stalled amid holds placed by multiple senators.

More disruption came during the 43-day government shutdown, accompanied by the expiration of the Cybersecurity Information Sharing Act of 2015 (CISA 2015), which set requirements for cybersecurity information sharing by the federal government and provided liability protections for voluntary information-sharing by private entities.

CISA's operations were restored on Nov. 12 when Trump signed a continuing resolution that also renewed CISA 2015 through Jan. 30, 2026, but the episode sparked fears about the continuity of the federal government's role in the cybersecurity ecosystem. (See *Stakeholders Urge Cyber Info Sharing Act Renewal*.)

Michael Ball, CEO of the Electricity Information Sharing and Analysis Center, acknowledged the turmoil of the past year and the concerns it created among stakeholders. However, he said that, despite outward appearances, the connection between the government and the ERO, including the E-ISAC, remains strong.

"There is a lot of concern about what that [relationship] looks like down the road. I can say with a lot of confidence, at least from the lens that I have, that we haven't seen that really degrade," Ball said. "We have great contacts within the different agencies. The changes haven't degraded the objective and the goal."

"Where my concern would be is the degradation over time in that [commitment], and my optimism [there] is pretty high," he continued. "We know that when there's administration changes, there tends to be [a shift] without stakeholders that we work through, and they tend to reconstitute and sometimes create new opportunities."

Cybersecurity remains a critical focus for NERC and the E-ISAC in 2026. As Russia's conflict with Ukraine continues, tensions between China and Taiwan intensify and other nation-state actors like North Korea and Iran jockey for advantage, the chance increases that those rivals will try to advance their interests by damaging U.S. infrastructure. Groups believed to be affiliated with China are known to have infiltrated U.S. telecommunications networks, and as they gain experience and confidence the threat is only expected to grow.

Risks also remain from straightforward criminal actors employing ransomware and other tactics to gain financial benefit. Ball said the growth of generative artificial intelligence is "enabling amazing capabilities, even for what would have been less sophisticated threat actors" to conduct social engineering campaigns and gain access to utilities' computer networks. These criminals are further fueled by an industry that has grown up to market malware, information and other cybercrime tools.

"The bad guys are bad, but they're not dumb. They're very, very capable … well-financed and well-resourced, and persistent — you can't let your guard down once, because they'll [be] there to take advantage of it," Robb said.

Standards Modernization, Large Loads Efforts to Continue

Cybersecurity is far from the ERO's only iron in the fire; NERC has multiple efforts underway that are expected to hit milestones in 2026. One of the most prominent of these is the Modernization of Standards Processes and Procedures Task Force, which the ERO stood up following a directive from the Board of Trustees in February 2025.

NERC's board started the MSPPTF to examine the ERO's standards development process after trustees twice invoked their authority under Section 321 of NERC's *Rules of Procedure* to break voting impasses over proposed standards that put NERC at risk of breaking a FERC deadline. Chair Suzanne Keenan urged the task force's leaders to make sure the process remains "stakeholder-based, with reasonable notice, opportunity for public comment, due process [and] openness." (See *NERC Leaders Highlight Canada-US Collaboration*.)

NERC has called the resulting work one of the biggest outreach efforts in the ERO's history, with presentations reaching more than 5,000 stakeholders over the last year. The task force is expected to deliver its final recommendations at the board's February meeting in Savannah, Ga. NERC will then work on updates to the ROP, which must be submitted to FERC for approval.

"We're still quite a ways away from implementation of a new process, but the team did a great job in living up to what we asked them to do," Robb said. "It hasn't been a smoke-filled room; there's been a lot of engagement, and … the task force has taken what they heard in those engagements and used it to make the process better [and] more palatable. … So [we're] very pleased with that."

NERC CEO Jim Robb testifies at FERC's annual commissioner-led Reliability Technical Conference in October 2025. | *FERC*

Large loads are expected to be another major area of focus for the ERO in 2026. NERC's Large Loads Task Force has been operating since 2024 to study the impacts of data centers, hydrogen fuel plants and other emerging large loads on grid reliability, along with multiple simultaneous other efforts.

The organization also issued a *Level 2 alert* in September 2025. The alert provided recommendations for registered entities to mitigate risks associated with integration of large loads into the grid while requiring responses to a series of questions on their experience with large loads, their understanding of the risks associated with large loads and their current efforts to address those risks. Responses to the alert are due Jan. 28, 2026.

Robb described the ERO's large loads work as "doing stuff in parallel that we would normally do in sequence." Along with the LLTF and the Level 2 alert, NERC is developing a reliability guideline on risk mitigation with emerging large loads and recently commented on an Advance Notice of Proposed Rulemaking at FERC discussing potential changes to NERC's registry criteria and standards actions on large loads.

"We won't get ahead of our skis, but we're going to be prepared to move as quickly as we can on each of these initiatives," Robb said.

Changes to LTRA Process

NERC will be carrying out its plans at a time when the ERO receives a growing amount of attention from lawmakers and the general public. As a sign of how NERC's profile has grown, Robb observed that at a 2024 meeting of the Senate Energy and Natural Resources Committee, both Chair Joe Manchin (I-W.Va.) and ranking member John Barrasso (R-Wyo.) used maps produced for NERC's reliability assessments. The CEO also mentioned a recent appearance on NBC's *Today* to speak about risks facing the energy grid.

"The CEO of NERC's not supposed to be on the *Today* show. Just think about that

— that the stuff that we're doing is reaching a mainstream audience, not just the nerds in the corner planning the electric grid," Robb said. "People are paying attention, and they're using our materials to inform decisions."

The increased attention to NERC's assessments forms part of the backdrop for the ERO's work to update its reliability assessments, particularly the Long-Term Reliability Assessment, which is published each year. The 2025 LTRA is due in January.

John Moura, NERC's director of reliability assessments, said ongoing changes in the electric grid — including rapid shifts from traditional generation to inverter-based resources like wind and solar, along with the growth of large loads — meant the ERO's previous approach to the LTRA was no longer valid. He described the former approach as "very much … ground-up," involving collecting data directly from utilities which the ERO would "piece together at the end."

Moura said recent experiences have demonstrated that "each system is more reliant on neighbors than we ever have been in the past … and so coming together earlier on in the process to make sure assumptions and scenarios and base cases are … modeled in unison [is] essential." NERC began a pilot program in 2025 to establish common platforms and standardized assumptions for the Eastern, Western and Texas interconnections, enabling interconnection-wide energy assessments.

That effort has been productive, Moura said, although not ready to be used in the 2025 LTRA. He explained that the Interregional Transfer Capability Study, filed with FERC in 2024 in accordance with a mandate in the *Fiscal Responsibility Act* of 2023, provided a "foundation" for the wide-area assessments by pushing NERC to develop tools and processes for information gathering and storage that could then be used for the LTRA.

"The ITCS gave us that step change. It kind of elevated our capability," Moura said. "If we had not had the ITCS … we would have [eventually] said, 'Wait, we need to understand the interregional transfer capability between the regions.' … But the ITCS actually gave us a step change up … allowing us now to do things in a simultaneous manner."

The most important task for NERC in the coming years, Robb said, will be to preserve its reputation for independence and fact-based analysis, and to avoid any perception of favoring one side or another in the increasingly polarized political climate.

"We've had as good a conversation with the current committees of jurisdiction in the House and Senate that we would have had two years ago, [and] our relationship with DOE is as strong today as it was two years ago, because we're not partisan," Robb said. "We're kind of the truth tellers. And while not everybody likes what we have to say, they at least respect it and pull it into their own thinking. I think that's really important … that we don't let ourselves ever be turned into a tool or start telling people what they want to hear, because once we do that, we've lost our power." ■