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Grid Weathers Latest Winter Storm but Still Faces Gas Coordination Problems

Xcel Energy

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Beware of Unintended Consequences

The Realities of Clean Energy Development in the Pacific Northwest

By Randy Hardy

Randy Hardy

Since 2019, the Bonneville Power Administration, Pacific Northwest utilities, independent power producers and other interested parties have struggled with politically required, but operationally difficult, development of renewable/storage resources in the region.

While much of this struggle involved slower than expected generation interconnection and transmission access/construction by BPA, the dynamics behind such clean energy development are considerably more complicated. As a former BPA CEO with over 40 years of dealing with PNW energy issues, I thought a more comprehensive analysis of this situation might be helpful.

Background

In 2019 and 2021, Washington and Oregon set ambitious clean energy goals, requiring their utilities to achieve 80% clean/decarbonized energy portfolios by 2030. At that time, those states' two main utilities, Puget Sound Energy (PSE) and Portland General Electric (PGE), were roughly 35 to 40% clean/decarbonized. Today they are only 45 to 50%. While such limited progress seems problematic, the nature of the non-ISO/RTO grid in the PNW and our specific transmission difficulties slowed renewable energy development substantially.

Geography

Northwest geography significantly complicates regional transmission development. Nearly all wind and solar sites are east of the Cascade Mountain Range, while loads are mostly in Seattle and Portland. In addition, current high-voltage cross-Cascades transmission lines are fully loaded. So devising methods to provide new transmission to PNW load centers or even upgrading existing 230-kV transmission to 500 kV across this environmentally sensitive barrier is a major challenge. I would estimate the degree of difficulty associated with overcoming this challenge, since it affects nearly all PNW renewables development, probably exceeds such geographic/environmental challenges in any other region.

Nearly all wind and solar sites are east of the Cascade Mountain Range, while loads are mostly in Seattle and Portland. Existing high-voltage cross-Cascades transmission lines are fully loaded. | *© RTO Insider*

Why This Matters

While well intended, Washington/Oregon goals of 80% clean/decarbonized energy by 2030 were set without consideration of the transmission access and construction realities BPA and other regional transmission providers would face, writes Randy Hardy.

BPA Generation Interconnection/ Transmission Access

BPA owns and operates roughly 70% of the region's high voltage transmission. Despite this transmission position, it operates, not as an RTO/ISO, but under FERC's Open Access Transmission Tariff (OATT) regime. It currently has 115 GW in its generation interconnection (GI) queue and, like RTOs/ISOs in other regions, is struggling to interconnect these resources as rapidly as possible.

Unlike those entities, however, as an OATT utility it also must operate a separate transmission access process complete with its own first-come, first-served queue for providing transmission capacity to renewable resource developers and others.

BPA typically processed this queue via an annual transmission cluster study that analyzed each submitted transmission service request (TSR) and thereby provided a specific plan of service for each such project. That CS queue has increased dramatically since 2020. Specifically: 2020 CS, 4 GW; 2021 CS, 6 GW; 2022 CS, 11 GW; 2023 CS, 17 GW; and 2025 CS, 65 GW.

This recent exponential growth in TSRs has stalled BPA's ability to analyze the 65 GW in its 2025 CS because of the multiple years required to perform such complicated power flow analyses and because the amount far exceeds any credible projection (even with data centers) of future PNW load. As a result, any project in the 2025 CS probably will not receive any long-term firm (LTF) transmission until well after 2030.

BPA TSRs From 2020-2023

For TSRs submitted to BPA from 2020 to 2023, the situation is better but still challenging. As a result of these TSRs, BPA plans to significantly expand its transmission portfolio, primarily through upgrading cross-Cascade 230-kV transmission lines to 500 kV, plus adding series capacitors and reconductoring existing high-voltage transmission.

This program, labeled its Grid Expansion and Reinforcement Portfolio (GERP), will cost $5 billion according to BPA, although realistically closer to $10 billion given all the environmental and procurement cost escalation factors involved. However, given the permitting realities, BPA staffing shortages and GI/TSR processing challenges, most GERP transmission projects will not be energized until well after Washington/Oregon 2030 80% clean energy deadlines.

The relatively good news: when eventually energized, GERP projects probably will enable PSE and PGE to meet their 80% clean energy goals. In addition, BPA also has enabled 3 to 5 GW of clean energy projects to reach Portland and Seattle by repurposing existing LTF transmission freed up by retirement of Colstrip and other thermal resources.

Complicating Factors

- Data Center Load Growth

Similar to electric utilities in other regions, PNW entities have experienced dramatic increases in projected loads driven by data centers and, to a lesser extent, electrification. From 2001 to 2022, annual PNW load growth equaled 1% or less. Loads from 2025 to 2034 now are estimated to grow by 2 to 3% annually.

Recent announcements of potential data center amounts/locations in the PNW total 12 to 15 GW by the mid-2030s mainly in Hillsboro (west of Portland), Salem or east of the Cascades (e.g. northeastern Oregon). Current data center load projections could easily be double or half of the 12- to 15-GW estimate.

In almost any case, they will increase regional loads substantially. This phenomenon dramatically increases the transmission capacity required to serve them, as well as the time needed to build such transmission and its cost. For example, over 3 GW of data center load is projected for Hillsboro (mostly in PGE's service territory), but reaching this densely populated area involves multiple 230/500-kV upgrades by BPA and PGE and likely will cost $2 billion or more.

- BPA Staffing

BPA experienced substantial staff reductions and associated turmoil resulting from the Trump/Musk actions in early 2025. While regional parties helped BPA avoid the worst of these, they still lost 200 of their 3,100 employees in February 2025 and, despite finally being exempted from the federal hiring freeze in November, have yet to even get back to their start of 2025 staffing levels. Then there's the additional 400-plus staff they are projected to need (bringing total eventual staffing to roughly 3,500) to timely process all the GI/transmission access requests needed to meet reliability/clean energy requirements.

Both the data center boom and administration staffing restrictions came at the worst possible time, given BPA's GI/TSR queues and unique transmission processing problems. Better late than never for DOE to exempt them from the federal hiring freeze, but the PNW effectively lost a year or more in its ability to identify and build the high voltage transmission necessary to meet PNW clean energy, reliability and data processing needs.

Conclusions

- While well intended, Washington/Oregon goals of 80% clean/decarbonized energy by 2030 were set without consideration of the transmission access and construction realities BPA and other regional transmission providers would face.
- Achieving such goals also was handicapped by emerging data center load growth and administration staff reductions on BPA.
- Perhaps most significant, besides these transmission realities, the 80% by 2030 mandates set off a virtual gold rush of TSRs, resulting in the 65 GW in BPA's 2025 CS queue that are not capable of being processed in any reasonable time frame — if at all.
- Many of these outcomes could/should have been foreseen and planned for. Others represented unfortunate surprises that were unanticipated under reasonable assumptions.
- The probable result: BPA/PNW will simply need to muddle through this mess over the next five to seven years. As mentioned before, GERP projects eventually will enable PNW utilities to reach 80%, but probably not until 2033 to 2035.
- Even with these transmission realities now plainly visible, Washington and Oregon legislators have yet to deal with the affordability of these clean energy mandates. This is an emerging problem but no doubt will worsen significantly in the next five years. Given that both PGE and PSE are only at 45 to 50% clean/decarbonized now, reaching 80% (whenever that occurs) will involve substituting 1 GW or more of renewable energy for energy from existing thermal resources. Such substitution involves replacing current coal/natural gas generation, probably costing utility consumers $40 to $50/MWh, with wind/solar which nominally cost $50 to $60/MWh busbar. However, when you include balancing, load following, additional transmission costs and purchasing additional energy to serve load when the wind does not blow or the sun is not shining, increases delivered cost to utility customers by $25 to $30/MWh. Then this $80 to $85/MWh delivered cost energy could well increase by an additional $20 to $30/MWh when federal tax credits expire, raising the overall cost for renewables to reach the 80% goal past $100/MWh. While this problem is belatedly being recognized, it has yet to be dealt with in any meaningful way by either state legislature.

Lesson Learned

Beware of unintended consequences. As this article hopefully illustrates, they already have adversely impacted the timing and (potentially) the cost of achieving 80% by 2030, and, if further action is not taken, they will further frustrate achieving such goals in the next four to five years. ■

Industry watcher Randy Hardy was CEO of the Bonneville Power Administration from 1991 to 1997. Prior to that, he held a similar title at Seattle City Light.

The Maryland 2026 Midterms Energy Trilemma Blues

Data Centers, High Utility Bills, Clean Energy and PJM are on the Legislative Agenda

By K Kaufmann


K Kaufmann

The way Maryland Del. Lorig Charkoudian (D) sees it, working with other Mid-Atlantic states to study the costs and benefits of withdrawing from PJM is, at this point, the only responsible thing to do.

"PJM is frustratingly slow in changing, if changing at all, [and] continues — even in a reliability crisis of their own making — to double down on their love affair with fossil fuels … at a really significant cost to our ratepayers. And so, you reach a point where it's almost irresponsible not to say, 'What are the other options?'"

Charkoudian was speaking during a recent legislative update call hosted by the Maryland Clean Energy Center (MCEC), where she previewed a package of bills she is sponsoring during the current legislative session, including *H.B. 143*, calling for the state to work with neighboring PJM states to study possible alternatives.

For example, the states — Maryland, Delaware, New Jersey, Pennsylvania and maybe Virginia — could start their own RTO or use PJM's fixed resource requirement (FRR) "to pull ourselves out of the capacity auction," she said.

Going the FRR route would require utilities in the states to procure their own capacity, rather than relying on PJM's increasingly expensive capacity auctions, and H.B. 143 also would require Maryland utilities to study the costs and benefits of ensuring they could provide at least 80% of their capacity.

"The idea is to explore doing more capacity procurement through bilateral contracts and then use the PJM auction" as backup, Charkoudian said in an email to *Livewire*.

The Maryland General Assembly kicked off its 2026 session Jan. 14, and as far as energy policy is concerned, Charkoudian predicts "an adventurous year … [with] a lot of moving parts."

Like Gov. Wes Moore's Lower Cost and Local Power Act — *announced* Jan. 27 — which could actually tie the state more firmly to PJM by requiring all utilities to join the RTO. The bill has yet to be formally introduced, but a one-page summary argues that having all the state's utilities in PJM — including small municipal utilities that generally have lower rates than investor-owned utilities — would lower electric bills.

The state's largest utilities — Baltimore Gas and Electric, Pepco Maryland and Delmarva Power, all IOUs owned by Exelon — already are members, as is the Southern Maryland Electric Cooperative. (See below for more details about the governor's bill.)

So, the 90-day legislative session ahead is shaping up as a case study in how states facing explosive demand growth will attempt to build more clean energy, cut electric bills and reduce greenhouse gas emissions as PJM and the Trump administration resist any change that puts more solar, wind and storage online.

Maryland aims for 100% carbon-free power by 2035 but imports 40% of its electricity from the regional grid, making it particularly dependent on PJM's mostly fossil-fueled power and vulnerable to any swings in the RTO's market prices. The state's consumers already are absorbing rate increases due to PJM's price-spiking capacity auctions, and more pain is ahead with the December auction, for 2027/28, hitting yet another record high, $333.44/MW-day, up from $28.92/MW-day in 2023.

Why This Matters

The challenge ahead for Gov. Moore and Del. Charkoudian will be getting their bills through a legislature that, even with a large Democratic majority, leans toward consensus, watering down more liberal bills with cuts, rewrites and amendments — or letting them die in committee.

"It's very easy to get caught up in all the drama around energy right now," Charkoudian said during the MCEC call. "[But] we have, for the most part, all of the tools that we need, and we need to put them together in the right policy."

Charkoudian vs. Moore

The politics of the upcoming midterm elections also are a key factor — Moore and all state lawmakers are running for re-election in November — affecting what new energy policies can be shepherded through the legislature and reach Moore's desk.

Both the governor and Charkoudian want to get more clean energy online in Maryland, to help wean the state off its dependence on PJM and provide support for local installers, developers and consumers in the absence of federal incentives cut off by the Republicans' One Big Beautiful Bill Act.

The 30% federal tax credit for residential solar was terminated Dec. 31, 2025. Commercial projects still can qualify for the credit if they start construction by July 4, 2026, and are online by the end of 2027.

The one-page summary of Moore's bill says it will "create a process for clean energy projects to apply for financing for shovel-ready projects," which, on the face of it, could primarily benefit utility-scale projects. (Residential and smaller commercial projects are rarely described as "shovel-ready.")

In contrast, Charkoudian's Affordable Solar Act (*H.B. 345*) lays out a detailed plan for Maryland to adopt incentives similar to New Jersey's, providing different levels of financial support for different kinds of solar — utility-scale, commercial, community solar and residential.

Incentives for utility-scale projects would be determined through a competitive auction, with the lowest-cost projects receiving incentives, while the state's Public Service Commission would set the price for solar renewable energy certificates (SRECs) for residential, community solar and commercial projects under 5 MW.

The PSC would review and adjust the

SREC price every three years, or more frequently if warranted by market conditions. Right now, the SREC price in New Jersey has been set at $85/MWh. Maryland SRECs are priced around $50, according to *Flett Exchange*, an online SREC trading platform.

New Jersey's utility-scale auctions got off to a rocky start, with the state's Board of Public Utilities rejecting all the bids in the first solicitation in 2023, saying they were too high. A *second auction* in 2024 awarded incentives to eight utility-scale projects totaling 310 MW.

Charkoudian described her proposed incentives as the "best bang for the buck from a ratepayer side, from a Maryland side. … We're going to provide as much subsidy as is needed, but not a penny more, to each different sector of the industry."

The bill also would make plug-in "balcony solar" legal in Maryland — a significant win for cutting home electric bills — and ensure that ratepayer dollars intended for the state's clean energy fund cannot be used to fill holes in the state budget. Moore wants to take $292 million from the fund — the Strategic Energy Investment Fund (SEIF) — to backfill a 2027 deficit estimated at close to $1.5 billion.

ATTs and Grid Expansion

Both Moore and Charkoudian are bullish on advanced transmission technologies, which can optimize and expand capacity on existing power lines, as a cheaper, faster alternative to building new transmission.

Moore's bill calls on utilities "to prioritize [ATTs] to expand existing grid capacity and authorize the use of state and interstate highway corridors to co-locate these projects."

Again, Charkoudian provides a more detailed approach in *H.B. 40*. Utilities or other transmission owners within the state would be required to identify areas where grid congestion has occurred in the past three years, as well as where congestion may be likely to occur over the next five years, and then develop plans for using ATTs as part of any grid upgrades or expansion.

Developers seeking a certificate of public convenience and necessity for transmission projects also would have to show they've considered ATTs as an alternative

Maryland State House | *Shutterstock*

to building a new line.

Charkoudian acknowledged that implementing the law could be tricky due to the fine line between state and federal regulation of new transmission. But she sees ATTs providing both grid efficiency and affordability.

An additional problem here is the slipperiness of legislative language. Any effort to get utilities to prioritize or consider new technologies tends to lead to highly technical arguments about why said technologies are not appropriate or feasible for any one project or situation. Compensation is another potential roadblock since upgrading wires with ATTs may be considered a maintenance cost that cannot be passed on to a utility's customers — that is, in many places, ATTs cannot be rate-based.

Moore's bill acknowledges that ATTs must be part of a bigger grid expansion strategy. The governor wants the Department of Transportation to use $10 million from the SEIF "to identify opportunities for high-voltage transmission lines and battery storage projects along state and interstate highways."

The focus on existing rights-of-ways could be a potential vote winner for the governor in the face of the well-organized and vehement local opposition to the Maryland Piedmont Reliability Project — a 70-mile transmission line approved by PJM, which could run through agricultural land in the central part of the state. The fact that the project is being built by an out-of-state utility, Public Service Enterprise Group of New Jersey, has intensified community outrage.

High Bills and Data Centers

Differences between Moore and Charkoudian are more pronounced when we get to the nitty-gritty of high electric bills and data centers.

Besides taking $292 million from the SEIF to balance the budget, Moore also wants to use $100 million for direct bill rebates to "Maryland families burdened by high energy costs" — yet another major vote winner. Both those withdrawals will leave the fund with a balance of about $164 million, according to an *analysis* by *Inside Climate News*.

What the governor doesn't mention is that in 2025, more than $94 million in SEIF dollars went to state programs providing bill assistance to more than 70,000 low-income families, according to the Maryland Energy Administration's *2025 report* on the fund. Projected spending for bill assistance programs in 2026 is $150 million. Whether Moore's rebates would go to upper-income households that really do not need them is unclear.

While Moore's bill is mum on data centers, the governor signed onto President Donald Trump's recent proposal that PJM hold a one-time emergency auction to deliver more long-term "baseload" power for data centers across its service territory — wording that assumes a traditional reliance on fossil fuels and nuclear.

Charkoudian tackles the data center dilemma in in her fourth bill, which proposes multiple strategies — and a preference for clean energy — to protect consumers from paying for any new generation or power lines needed to connect these megawatt-guzzling facilities to the grid.

The bill is being finalized, but according to a fact sheet from Charkoudian's office, the core provisions include:

- Accelerated permitting and interconnection for new data centers or other large loads that supply 100% of their power.
- A voluntary demand response program for large load customers — defined as any facility with a demand of 25 MW or more.
- An inventory of surplus interconnection capacity in the state, conducted by the Maryland Energy Administration. The information gathered by MEA "will be shared with large load customers who can then use this surplus interconnection to build new battery storage or other zero-emission resources to avoid having to go through the PJM queue," according to a fact sheet on the bill.
- A requirement for all new large load customers seeking interconnection in Maryland to cover the capacity for at least 25% of their power demand with either behind-the-meter resources, storage or carbon-free power.
- A community benefit fee of $1,000/MW to be paid by any large load project applying for interconnection in Maryland. The fee would cover the cost of interconnection studies and be used to provide consumers with assistance for high utility bills and energy-efficient home upgrades.

Both Moore and Charkoudian appear to be moving in the same direction, tackling critical challenges for the state — in this case, how to develop a reliable, affordable electric power system with growing amounts of clean energy, an optimized, flexible grid and various pathways for data centers and other large loads to get the power they need.

Charkoudian tends to go big, ambitious and strategic on the bills she introduces, while Moore is smart, but perhaps a bit more cautious, with an eye on the election and Maryland's mix of liberal and more conservative voters. Pressure from the White House, PJM, utilities and hyperscalers will be intense.

The challenge ahead for both will be getting their bills through a legislature that, even with a large Democratic majority, leans toward consensus, watering down more liberal bills with cuts, rewrites and amendments — or letting them die in committee.

In other words, the fate of clean energy, data centers and utility bills in Maryland and other PJM states will depend on the difficult, frustrating but absolutely vital process of making laws in a democratic society, with a free, independent press looking on. Thank goodness, in Maryland, we still have both. ■

Leadership in a Time of Systemic Climate Risk

By Dej Knuckey

Dej Knuckey

For most of the electrical industry's history, weather was a constraint we designed around. Climate, by contrast, now is a system we operate inside of: a wild, unstable system.

That distinction matters more than many grid leaders, regulators and policymakers have absorbed. *Extreme heat*, *wildfires*, *intense rain*, *drought* and *sea level rise* often are approached as separate hazards — each deserving its own planning docket, modeling exercise or capital program. And while this column just completed a series on the impact of each hazard on the grid, they are not a collection of independent risks; they are a tightly coupled system of climate-driven stresses that interact, compound and persist in ways the grid never was built to handle.

Climate risk no longer is an environmental problem. It's a governance, planning and management problem. And it sits squarely on the desks of utility executives, system operators and policymakers.

From Discrete Events to Systemic Risk

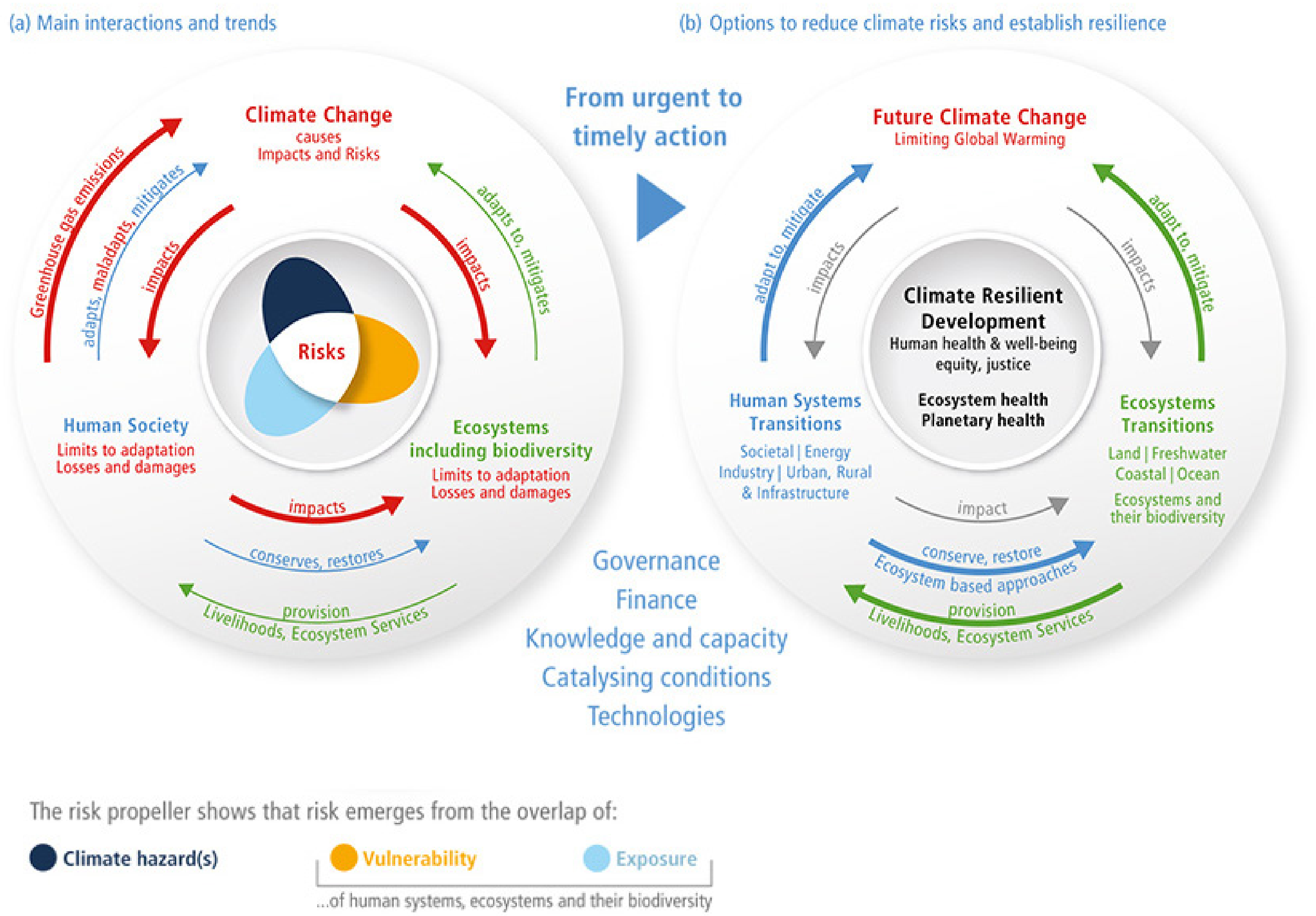
The industry knows how to deal with events. We respond to heat waves, storms, fires and floods when they occur individually. Mutual assistance is activated, crews are staged, emergency declarations are issued and restoration begins.

Why This Matters

The question facing leaders and policymakers is not whether the lights can be kept on during the next storm, it is whether governance structures, planning tools, and investment frameworks can evolve fast enough to manage permanent instability.

Climate change has turned those events into conditions.

Heat no longer is a single-day peak but a



Climate risks interact and compound | *IPCC* multiday, multinight stress that simultaneously drives record demand, reduces generation efficiency and lowers transmission capacity. Drought is not just a hydroelectric issue; it constrains thermal cooling, increases wildfire risk and exposes weaknesses in the water-energy nexus. Wildfires are not seasonal hazards but year-round threats with cascading impacts on air quality, solar output, worker safety and liability exposure. Extreme rainfall doesn't merely knock down lines; it floods substations, undermines foundations and complicates recovery logistics. Sea level rise isn't a future storm-surge problem; it's a slow, permanent redrawing of where infrastructure can safely exist.

Taken together, these risks do not stack neatly. They collide.

A heat dome can arrive during a drought, elevating fire risk. Fires strip vegetation, increasing the likelihood of debris flows and flash flooding when rain eventually comes. Flooded substations disrupt power to water systems just when pumping capacity is needed most. Smoke degrades solar output and limits air operations for line inspections. Each stress amplifies the next.

We can't plan for each hazard in isolation.

Polycrisis, Meet Multisolving

Two terms I keep coming back to as I consider how the industry will manage in a future in which uncertainty is the norm are polycrisis and multisolving.

The term "*polycrisis*" was coined by French complexity theorists in the early 1990s and popularized in the early 2020s as the planet struggled with a pandemic, climate change, wars and economic instability. Climate change interacts with energy sources, generation, transmission and distribution infrastructure and the safety, well-being and economic stability of residential and commercial customers. It interacts with other critical infrastructure systems that both depend on and support the grid. And this is happening against a backdrop of income inequality, declining health outcomes, population migration and unstable federal emergency management support. Climate is not a single crisis for the grid.

"*Multisolving*" was coined by Dr. Elizabeth Sawin and focuses on the positive flipside of the coin: solving for one problem can solve for others. Think of it as the BOGO of the solutions crowd. For the grid, building resilience against one extreme challenge comes with the bonus of creating resilience against others, with a further ripple effect of improving reliability and lowering corporate exposure. Similarly, decarbonizing the grid with renewables and energy storage comes with the bonus of lowering exposure to fuel prices, increasing grid stability and improving the health of communities near power generation.

They are both linked to unintended consequences: polycrisis in a negative sense where one challenge results in multiple, compounding challenges; multisolving in a positive sense where one solution solves more than one challenge.

Grid Resilience in the Time of Climate Change

Most grid planning frameworks still assume three things that no longer hold: historical climate baselines, independent hazards and short disruption durations.

Reserve margins, resource adequacy models and integrated resource plans often are still calibrated to yesterday's weather. Reliability metrics reward fast restoration after discrete outages, not the ability to avoid catastrophic system failure during prolonged, overlapping stresses. Yesterday's *n*-1 contingency planning won't work when climate delivers *n*-many failures simultaneously.

The problem isn't a lack of data. Climate science has advanced rapidly, and hazard modeling is more sophisticated than ever, assuming inputs and assumptions are adjusted for today's reality. The problem is institutional inertia: Planning processes and regulatory structures have not evolved at the same pace as the risk landscape.

The industry needs to focus on correlation risk. Heat waves reduce solar efficiency at the same time demand peaks. Wildfire smoke causes "wiggling" in photovoltaic output while also limiting crew deployment. Flooding disrupts electricity, communications and transportation at once. These interactions are predictable and need to be built into planning assumptions.

There are resources to help with this planning challenge, such as the *National Association of Regulatory Utility Commissioners' tools* for public utility commissions.

This planning needs to be done against a backdrop of rapidly accelerating risk. The creators of the *First Street Correlated Risk Model* found, "the frequency of losses resulting from major climate disasters in the U.S. has increased over fivefold in the past four decades, with climate change and increased development in vulnerable areas being the primary drivers."

And there's no one-solution-fits-all. Existing adaptation approaches typically assume rather simplified models, an *IEEE study found*. "The reality, however, is that climate change patterns and the uncertainties they introduce can differ regionally, complicating the formulation of effective countermeasures."

As climate hazards become more frequent, more extreme and more varied, the industry can't afford to rely on plans that appear robust on paper but are brittle in practice. The industry must invest in comprehensive planning and prioritize infrastructure upgrades that address multiple risks.

Climate Risk Has Become a Balance Sheet Issue

The most underappreciated shift may be financial rather than technical.

Climate exposure is reshaping utility balance sheets. Wildfire liability has driven bankruptcies and forced restructuring, insurance providers are retreating from high-risk regions or sharply raising premiums, and credit rating agencies are flagging climate exposure as a material risk. Capital costs are rising fastest for utilities with the greatest climate vulnerability, often the same utilities facing the largest infrastructure reinvestment needs.

In effect, climate risk is becoming a *de facto* regulator, often acting faster and more bluntly than public utility commissions.

This matters because resilience investments too often are framed as discretionary or extraordinary: nice to have if regulators approve, deferrable if rates are politically sensitive. But in reality, failing to invest in resilience now simply shifts costs forward, where they reappear as higher borrowing costs, insurance gaps, emergency repairs and, ultimately, customer harm.

Swiss Re Institute, which studies the risk landscape closely — because reinsurance companies are the ones pricing the growing risk — said, "Ongoing risk assessment is necessary to ascertain how resilient infrastructure is. Assets that are poorly maintained are more vulnerable."

Conversely, today's resilience investments can pay dividends beyond repairing and preparing for the same risk. Think about the $1 billion, four-year Con Edison *storm fortification initiative* following Superstorm Sandy: It was triggered by outages following a storm surge, but is paying dividends as the utility faces ice storms, heat waves and more.

Executives who treat climate adaptation as an environmental compliance issue are misreading how quickly financial markets are moving.

No Utility is an Island

Another lesson emerging across climate hazards is that grid resilience cannot be built in isolation. Power outages cascade. They shut down water pumping and wastewater treatment. They cripple communications networks. They undermine emergency response and health care delivery. During fires and floods alike, loss of electricity turns manageable crises into life-threatening ones.

Yet in many states, energy planning remains siloed from water utilities, emergency management agencies, transportation departments and telecom providers.

Cross-infrastructure coordination can't be ad hoc or occur only after a disaster. Integrated planning and response reduce both risk and cost. If infrastructure needs to be protected from rising sea levels, for example, it'll be more cost effective if all affected agencies coordinate resilience investments, hardening power, water, wastewater treatment and roads simultaneously.

At the same time, a region may be more of an island than ever before: If multiple states face an event at the same time, like the winter storm that recently shut down a solid slice of the lower 48, mutual aid agreements break down as crews are needed locally and flying in distant crews becomes impossible. Mutual aid is ideal, but some disasters will be more *Lord of the Flies* than *Swiss Family Robinson*.

Resilience is not something the power sector can buy on its own. It is an inter-

Planning for grid resilience requires a comprehensive framework such as the one developed by NARUC. | *NARUC*

dependent system, and governance structures have to reflect that reality.

What a Climate-adjusted Grid Strategy Actually Looks Like

If climate risk is now a core management challenge, what follows is not a checklist of projects but a shift in mindset.

First, resilience must move beyond asset hardening toward system flexibility. Hardening substations and elevating or undergrounding equipment remain necessary, but they are insufficient on their own. Islandable microgrids, distributed energy storage and modular recovery strategies allow systems to absorb shocks rather than simply resist them. Flexibility — not brute strength — is what enables systems to function under compound stress.

Second, planning must explicitly account for duration. Multiday heat waves, weeks of wildfire smoke, yearslong droughts and permanent sea-level rise pose fundamentally different challenges than short, sharp events. Planning processes that focus on peak hours or single-day extremes underestimate both operational strain and human fatigue.

Third, we must align incentives with future conditions. Regulators play a critical role here: Cost-recovery frameworks still favor post-event rebuilding over preemptive adaptation, even though avoided outages and avoided disasters deliver far greater public value. Utilities, for their part, need to treat resilience as a core dimension of service quality — not a regulatory add-on.

Fourth, reliability metrics need updating. Measures that prioritize restoration speed after outages do little to encourage investments that prevent catastrophic failure in the first place. In a climate-altered grid, success increasingly looks like outages that never happen, liabilities that never materialize and emergencies that never escalate.

Leadership in a Non-Stationary World

The grid already is operating inside a climate-stressed environment. The question facing leaders and policymakers is not whether the lights can be kept on during the next storm, it is whether governance structures, planning tools and investment frameworks can evolve fast enough to manage permanent instability.

That evolution will be uneven. Some utilities and system operators are already internalizing climate risk as a core design constraint. Others remain trapped in a compliance mindset, waiting for clearer regulatory signals or the next disaster, legal action or insolvency to force action.

The future of our industry will not be defined by how cheaply it delivers electrons, but by how well it absorbs shock, and that can happen only if leaders treat climate risk as the multidimensional management challenge it has become. ■

Grid Weathers Latest Winter Storm but Still Faces Gas Coordination Problems

By James Downing

The North American grid made it through the winter storm of Jan. 24-26 — dubbed "Fern" by The Weather Channel — relatively unscathed, but the cold weather gripping much of the U.S. and Canada continues, and cold snaps in the future will still stress the interconnected power and natural gas systems.

The industry mobilized ahead of the storm, sending out more than 65,000 workers from 44 states to start damage assessments and repairs as soon as possible, according to a news release from the American Public Power Association, Edison Electric Institute and the National Rural Electric Cooperative Association. As of 9 a.m. Jan. 29, 750,000 customers have had their power restored, but work continues, especially in areas that saw an inch or more of ice accumulation.

"This unified effort includes close coordination with federal, state and local officials who share the goal of safely restoring power as quickly as possible," EEI CEO Drew Maloney said. "The massive mutual assistance mobilization has ensured we have enough workers in place, with crews shared across the region and reassigned to the next priority as soon as they wrap up work."

The Electricity Subsector Coordinating Council has held three calls to coordinate the response between the industry and federal government.

"Thanks to the work of our industry partners, mutual assistance crews are restoring power as quickly and safely as possible across the country," Deputy Energy Secretary James Danly said in a statement. "Since Winter Storm Fern began on Jan. 24, the department has issued eight emergency orders to stabilize the electric grid across impacted regions; the department is using all of the available tools at our disposal to mitigate power outages and save lives."

While the industry wraps up work connecting customers who lost power because of distribution outages and faces some ongoing cold in the coming days, winter reliability will continue to be an issue for the foreseeable future, experts said during a webinar hosted by R Street Institute on Jan. 29.

The biggest risk to bulk power system reliability in the coming years is whether the industry can respond to growing demand from data centers and other sources, but recently retired ISO-NE CEO Gordon van Welie listed the gas-electric issue as a close second.

"The biggest secondary factor is this mismatch between planning and paying for the gas system and the electric system, and the mismatch between the reliability standards for these two systems and the lack of recognition that the gas and electric systems have become one interdependent energy system," van Welie said. "And we're still regulating these systems as if they exist in independent silos."

Winter reliability depends on weatherizing equipment and ensuring adequate fuel during cold snaps, which requires strong performance incentives in the wholesale markets, investment in the required fuel infrastructure and some way to recover those costs, he added.

After Winter Storm Uri in February 2021, FERC and NERC made significant improvements to the point where that is "largely solved," van Welie said. The two industries have also worked to improve information sharing, but that has provided only incremental gains, he said.

The real need is for more infrastructure, van Welie argued. But while the two systems have become increasingly interdependent, they are regulated differently.

"The restructuring took different paths with different economic structures for cost recovery," van Welie said. "And the consequence now, since they've become interdependent, is this total mismatch in terms of cost recovery for the underlying network, so I'm not talking about production here of gas, but the networks for delivering the gas."

Inadequate gas infrastructure can lead to unreliable electricity supply, which compromises all aspects of the economy, including the ability to deliver gas to heat homes during cold snaps. After Uri, van Welie asked RTO staff to work with electric utilities and local distribution companies to estimate how the system in the Northeast would handle similar outages as seen in Texas.

Why This Matters

The interdependent nature of the power grid and gas pipeline system will continue to create issues for reliability in the winter without additional major changes, several industry observers said.

"The biggest alarm bell came from the gas LDCs, who said, 'There's no way we can tolerate rotating feed outages, because what we'll end up doing is a flameout,'" van Welie said. "'We'll end up with a flameout on the gas system. It'll take us weeks to restore the gas system.'"

That nearly happened during the cold snap over the holidays in 2022 to Consolidated Edison's LDC serving New York City. (See *Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages*.)

"I fear we're going to need another 2003 event to really move the needle on this issue," van Welie said.

The Northeast blackout in 2003 gave Congress the impetus to create a mandatory reliability system for the grid with the Energy Policy Act of 2005. Van Welie said the same kind of shock could force it to finally better align the gas and electric systems.

New England has been facing gas-electric coordination issues for more than two decades, but as Electric Power Supply Association CEO Todd Snitchler recalled on the webinar, it has been a focus at FERC since at least 2011.

"Well, that was 15 years ago, and we still haven't solved it," he added. "I do think we've made progress, and I'm happy to say that that's been the case."

| Xcel Energy

The current cold snap is affecting a wide swath of the country, and so far, those improvements have borne fruit, with the two industries working well together, Snitchler said.

"I think the information sharing has improved dramatically," he added. "I think the ability for the RTOs to interact with the gas system and with the power system and speak more common language has improved fairly significantly."

Getting more infrastructure built would help, but Snitchler said cost recovery is an important issue.

"Markets treat cost recovery differently. Independent market monitors have different views about what's eligible for cost recovery and what can be bid into the system," he said. "And I think those questions are yet to be fully resolved in a way that helps to mitigate the volatility and stressful conditions but ensures, ultimately, that reliable system."

Even outside of the issues in winter, the need to meet data center demand is going to require additional gas pipelines — and electric transmission lines, he added.

Uri hit Texas worse than anywhere else, as ERCOT suffered major outages exacerbated by gas-electric coordination issues, leading to hundreds of deaths. ERCOT's former Independent Market Monitor and R Street Fellow Beth Garza noted that the gas-electric issues are different in Texas because of the lack of restructuring on the gas side.

"In Texas, the majority of natural gas-powered generation is supplied by intrastate pipelines [that] aren't required to have the same kind of unbundling and restructuring that has happened in the rest of the country," Garza said. "I would just point folks to the aftermath of Uri. Look at the profits that Energy Transfer; look at their profits of billions during that event, *versus* the loss of the largest generator in Texas, Vistra, which were also in the billions. And that, to me, tells a story."

The oil and gas industry is politically powerful in Texas, and it has not been restructured at all, which is the opposite of what has happened in ERCOT's electricity market, she added. The biggest thing aimed directly at winter reliability since Uri was that generators started getting paid to keep oil stored on-site at dual-fuel units, but Garza sees a bigger need for stored fuel.

"There needs to be an investment in gas storage," she added. "It's not just pipelines. It's the ability to withstand, particularly in the wintertime, the production decreases that are going to happen because of the cold weather."

One state that has done well with gas-electric coordination issues is Florida, which has the highest percentage of gas generation and is at the end of the pipeline network like New England, NERC Director of Reliability Assessments John Moura said.

"They build the gas pipeline for the generators," Moura said. "They're high-pressure contracts. They have a mandate to have oil backup because there's a good amount of generation, 16,000 MW, that is south of any other pipeline options —kind of a single contingency there, so there's dual fuel. So, they've done things, worked it into their integrated resource plans, not the markets. But I think there's things to learn from the signals that they're putting in them." ■

EPRI Suggests Path to Limit Grid Costs of Data Center Surge

Report Lays out Scenarios Under Which New Large Users Could Lower Costs for Other Grid Customers

By John Cropley

The expected rapid addition of large loads to the grid need not raise electricity rates, EPRI explains in a *new research paper*.

The authors conclude that if the incremental costs of serving the new loads are below the current average costs, new demand can actually lower the average retail rates as the system costs are spread across a wider base.

However, this depends on excess grid capacity or a relatively cheap source of new electrons being available.

If, instead, expensive grid investments are needed to serve that new load, or if the new load reduces its demands before those investments are paid for, the opposite effect can be seen: Prices could rise for other customers on the grid.

That is the root of the growing consternation about the largest component of the large load influx expected for the U.S. grid: data centers. As electricity rates surge far above inflation, there are growing calls to make these facilities pay their own way. (See *U.S. Utility Rate Increase Requests Topped $30B in 2025*.)

EPRI President Arshad Mansoor said in a *Jan. 29 news release* the research paper shows a path toward the right balance: "As AI, electrification and industrial onshoring reshape the U.S. energy landscape, understanding how load growth interacts with system costs has never been more important. This research shows that with planning, pricing structures and flexible demand, growing electricity needs can support affordability and reliability for all."

Why This Matters

The analysis offers factors that can blunt the feared financial impact of new data centers and other large loads.

"Win-Win Watts: When Can Data Centers, Efficient Electrification and New Loads Lower Electricity Prices?" suggests three main action points:

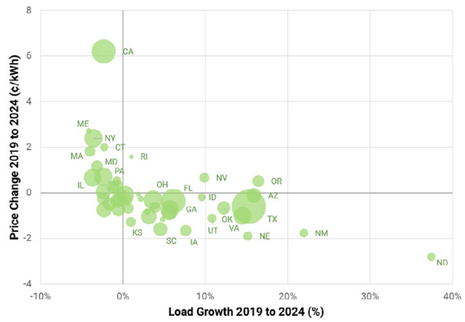
- rate design and cost allocation that protect existing customers;
- demand flexibility; and
- proactive planning that links demand with clean energy and grid investments.

Striking the right balance could lower costs, accelerate clean energy resources, support emerging technologies, reduce emissions and support better system operations.

The authors acknowledge the challenges implied in all this: "Whether those 'win-win' outcomes are realized depends on rate design, infrastructure needs and policy choices that affect whether new loads cover their costs and risks. Some answers depend on testing new technologies and business models, such as [EPRI's *DCFlex Initiative*'s] demonstrations of data center load flexibility, that could offer new tools for managing growth while protecting affordability."

The factors that help determine whether a new load raises or lowers electricity prices include:

- system conditions: generation mix, current average costs, demand profiles, spare capacity, investments in the pipeline and reliability requirements;
- shape of new loads: size, load factor, coincidence with net system peaks and ability to shift or curtail demand during stress periods;
- technologies available: costs and performance of new generation, energy storage and demand-side options, including how quickly they can be financed, permitted and built; and
- regulatory and market context: in cost-of-service regions, more of the new infrastructure costs show up directly in rates; in restructured markets, more of the impact shows up in wholesale prices and contracts that large customers sign with suppliers.



An EPRI graph shows the relationship between load growth on states' grids and electricity price changes from 2019 to 2024. | *EPRI*

A correlation emerges in state-level analysis: States with faster load growth from 2019 to 2024 experienced smaller price increases or even price decreases, but states with flat or decreasing power sales saw larger price increases.

Large loads, the authors note, tend to locate where they expect future costs to be favorable.

Factors identified as supporting affordability amid large load growth:

- incremental costs for generation, transmission and distribution additions being lower than present average costs;
- high and predictable rates of utilization, to avoid wide gaps between contracted and realized load;
- data availability and baseline transparency, so that flexibility can be incorporated into planning;
- favorable load shapes and flexibility, so the new demand either flattens the system profile or does not contribute to its coincident peaks; and
- well-designed tariffs and cost allocations that ensure large load customers cover the costs and risks they impose and are compensated for flexibility they offer.

EPRI, which describes itself as "rigorously objective," has a board of directors populated almost entirely by top executives of major power providers. ■

U.S. Utility Rate Increase Requests Topped $30B in 2025

Report Explains Reasons for Surge, Effects on Consumers and Politics

By John Cropley

A *newly published review* of utilities serving 81.1 million U.S. customers found $30.5 billion in 2025 rate hike requests — a record high, and twice as much as was sought in 2024.

The report *issued Jan. 29 by PowerLines* further quantifies what has become a salient political issue: rising energy costs.

"As these costs keep climbing," PowerLines Executive Director Charles Hua said, "policymakers of all political stripes will face growing pressure to take action and advance solutions to improve our grid and lower utility bills for American consumers and businesses."

Rate hike requests do not go through unchanged, and state utility regulators of all stripes continually announce steps to protect ratepayers.

But even with that regulatory effort factored in, the impact of rising prices is being felt. The report notes that an estimated 80 million Americans struggle to pay their utility bills and more than 50 million keep their homes at unsafe or unhealthy temperatures. More than 20% of American households experience energy poverty, spending over 6% of their income on energy bills.

Monthly utility bills — which include charges and/or credits beyond rates — increased 10.8% for piped gas and 6.7% for electricity from December 2024 to December 2025 while the overall U.S. inflation rate was just 3%, the authors write. Since the first quarter of 2021, residential retail electricity prices have increased approximately 40%.

Electricity and natural gas prices have become the fastest drivers of inflation, the report states.

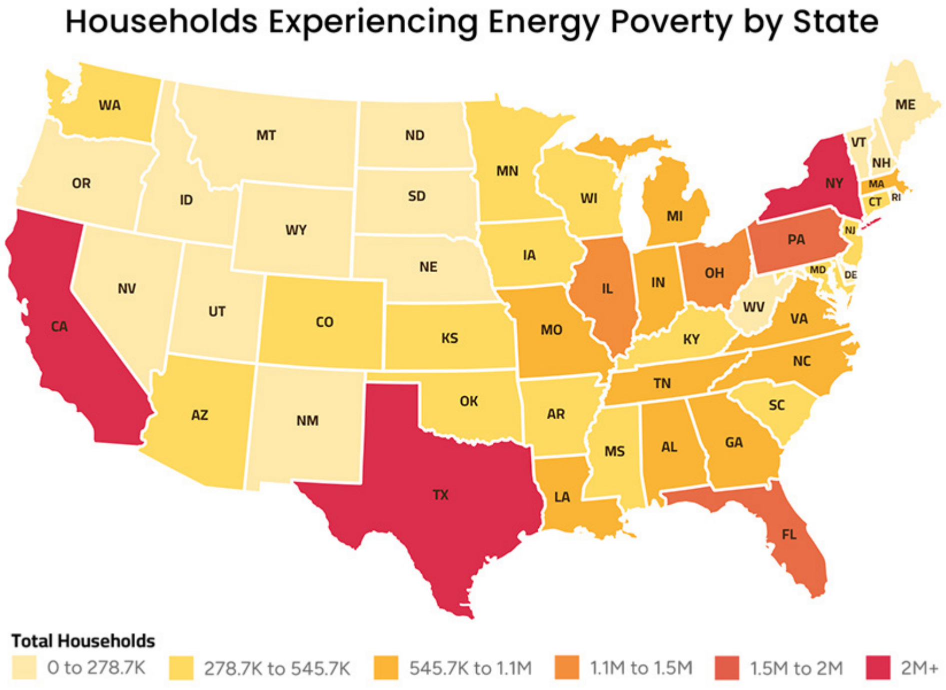
Commercial and industrial electric prices did not increase as sharply as residential prices in 2025, only about 5%. But such increases typically are passed on to consumers through higher costs for goods and services.

A March 2025 poll conducted by Ipsos for PowerLines concluded three in five Americans were not familiar with the public regulatory board that controls their utility bills, three in four are concerned about rising utility bills and four in five feel powerless over these costs.

Against this backdrop, it was inevitable perhaps that rising utility bills would become a leading political issue. PowerLines expects these costs to be a top concern for voters in the midterm elections, particularly in competitive 2026 congressional and gubernatorial races.

Why This Matters

The report lays out some of the causes and impacts of soaring U.S. utility rates.



U.S. Department of Energy data shows the number of households experiencing energy poverty in the contiguous 48 states. | *PowerLines*

The report notes that early projections for 2026 do show some moderation: The Energy Information Administration expects electricity prices to increase about 4%, but that still is much more than the Federal Reserve's projected 2.4% inflation rate.

Collecting data from public databases, news reports, press releases and utility regulatory filings, PowerLines counted $30.5 billion in 2025 rate increases compared with $15 billion in 2024.

The impact was most intense in the Northeast, where $6.5 billion in rate increases spread across 11.5 million customers were sought. The least intense impact was in the Midwest — $3.2 billion in increases affecting 16.7 million customers.

In between were the South ($14.3 billion across 32.9 million customers) and West ($6.5 billion across 20 million customers).

Each of the rate increase requests is different, but four key factors emerged as PowerLines analyzed the data collected: aging infrastructure that needs to be replaced; repairing damage from past extreme weather or making upgrades to prevent future damage; volatile fuel costs; and rising electricity demand, although some utility markets and some investments are structured so that rising demand can lower electricity prices by spreading costs over a broader customer base.

The authors note also that utility capital expenditures — a key driver of profit for utilities and costs for their ratepayers — increased more than 14% between 2024 and 2025. ■

Senate Hearing Shows Support, Potential Pitfalls for Permitting Legislation

By James Downing

Bipartisan leaders of the Senate Environment and Public Works Committee want to pass energy infrastructure permitting legislation, but a Jan. 28 hearing on the subject showed how that might not happen during this Congress.

Senators, including EPW Ranking Member Sheldon Whitehouse (D-R.I.) and leaders from the Energy and Natural Resources Committee, have been working on potential legislation for the past year but are trailing House colleagues who passed a bill late in 2025 that would alter the National Environmental Policy Act to speed up permitting. (See *House Passes SPEED Act to Quicken Infrastructure Permitting*.)

"I'd like to begin by thanking my colleagues who are here with me, and in particular, Ranking Member Whitehouse, for their drive to elevate problems in our current permitting regime and to work constructively together," EPW Chair Shelley Moore Capito (R-W.Va.) said at the start of the hearing. "That's what we need to do."

"It's the never-ending story on permitting, but we're going to get into that story — I hope," Moore Capito said.

Any bill needs to be bipartisan to be durable, she said before Whitehouse made his opening remarks, saying he shared that goal but thinks there is a "trust problem" with the Trump administration. He cited the president's executive orders that temporarily stopped the Empire offshore wind project.

Why This Matters

There is a window for permitting legislation early in 2026 before Congress turns its full attention to the fall midterms, but for Democrats any workable bill will require a political deal with the Trump administration over its handling of clean energy projects.

"This all stank, but I remained willing to work on a permitting bill," Whitehouse said. "In August, stop-work Trump struck again against Revolution Wind off Rhode Island, a project over 80% complete with $4 billion invested, based on supposed national security concerns. That order was instantly thrown out in court as arbitrary and capricious, in part because the Trump administration had been making the opposite arguments about that same project in the same courthouse just weeks earlier."

Construction of the Cardinal-Hickory Creek transmission line | *ATC and ITC Midwest*

Other actions against clean energy continued through 2025.

"So, Sen. Heinrich [D-N.M.] and I have paused permitting reform negotiations," Whitehouse said. "Let me be clear: We find no fault with Senate Republicans."

The conflict is entirely between the legislative and executive branches of the government, according to Whitehouse, who said the Trump administration's "lawless" attacks on clean energy loom over every other industry. The executive can resuscitate the bill's prospects if it shows it will stop putting up roadblocks to clean energy, Whitehouse said.

'Essential'

The Solar Energy Industries Association is not focused on reforming NEPA, which the SPEED Act and any Senate proposal from EPW would do, because the law is rarely used in litigation against solar projects, said SEIA CEO Abigail Ross Hopper, who said "permitting is essential."

"SEIA strongly supports these bipartisan efforts to improve the process for energy and transmission projects," she said. "Permitting reform must begin with this basic principle: Projects that enter the federal permitting process must be allowed to move through that process in good faith and without unfair treatment based on energy source. And once a project receives a permit, that permit should be honored."

The solar and battery developers that SEIA represents have run into issues with the Trump administration since a July 2025 Department of the Interior memo created "68 new layers of red tape" for their projects, she added. By requiring secretarial approvals on many easy decisions, it effectively amounts to a moratorium on solar.

The bureaucratic roadblocks are endangering 70 GW of solar and 42 GW of battery storage on both federal and private land," Ross Hopper said. Together they represent 43% of all planned new capacity in the U.S.

"We all know electricity demand is rising rapidly, and without this power and the grid infrastructure to deliver it, electricity prices will continue to rise," she said.

Sen. Ed Markey (D-Mass.) noted that the tactics being used against solar now could be wielded against the oil and gas industry in the future by a Democratic president. He entered a *memo* into the record from Evergreen Action laying out how to get that done.

"This administration must be forced to end its punitive treatment through clear legislative text and vocal Republican opposition to any efforts to violate the law," Markey said.

After Markey's turn on the mic, Sen. Cynthia Lummis (R-Wyo.) responded that previous administrations from his party had done the same kind of thing against infrastructure they disliked.

"Mr. Markey, we feel your pain. We could take your statement and where you said left — we could put right," Lummis said. "Where you said right, we could put left. Where you said Trump, we could put Biden."

One of the first things former President Joe Biden did when taking office in 2021 was to stop construction on the Keystone XL pipeline, she added. Markey countered that Trump has taken more such actions before Chair Moore Capito reminded him it was Lummis' time to speak. ■

Customer Group Offers FERC Policies to Grow the Power System Affordably

By James Downing

FERC must balance the need to grow the grid while keeping rates affordable for customers, the Electricity Customer Alliance argues in a recent white paper laying out suggestions to thread the needle.

The authors of "*A Customer-Centric Agenda for FERC*" argue that the commission will play a key role in making sure the wholesale power markets are designed in way that can serve exponentially rising demand from data centers, reshoring manufacturing and electrification. It also has an important role in convening state regulators to address issues, as it has in recent years alongside National Association of Regulatory Utility Commissioners meetings.

ECA's members are all kinds of customers, from hyperscale data centers down to consumer advocates for residential customers, and it advocates for maintaining a reliable grid while keeping rates affordable, Executive Director Jeff Dennis said in an interview.

"We see a number of issues swirling around FERC and wholesale electricity markets and the transmission grid," Dennis said. "There's just a lot going on out there. And our goal is really to take a lot of those issues and put them in a customer-centric framework that really connects the dots for the commission and other stakeholders around our national bipartisan goals for AI leadership, national security, economic growth and improving affordability for customers."

So far, the impact of the return of load growth has not led to lower prices, with PJM seeing its capacity market prices surge as demand from data centers has led the market to fall short of its target reserve margin.

A big reason for the climbing prices in PJM is the load forecasts the RTO relies on to set the curve for its capacity market, Dennis said.

"I pinpoint the load forecast because I think as we've seen, those load forecasts are incredibly uncertain," he added. "PJM itself has dialed those back almost in half.

Why This Matters

ECA represents a broad cross section of customers who could benefit from the paper's suggestions to maintain reliability and affordability while meeting new demand from data centers and other sources.

And so, the challenge that we're facing right now is we have these load forecasts that are projecting large growth." (See *Pessimistic PJM Slightly Decreases Load Forecast*.)

Load forecasts include many big developments that are unlikely to be economic any time soon and can suffer from double counting as well, Dennis said.

"I think on top of that, we're living in a world where the price signal that the capacity market produces is being felt by customers much sooner because of the delays that we've experienced in the auctions in PJM over the years, and so we don't have that three years forward," he added.

Load growth can mean lower prices for existing customers as the costs of the bulk power system are spread over a larger base. ECA's paper argues for steps to get to that end state, where development of supply keeps pace with demand growth. The right structures for regional planning and cost allocation need to be struck to get to that state.

"We have to integrate these loads into the network in order to get those benefits," Dennis said. "The whole goal is, if you can bring in new customers and new load below the peak, then what you're doing is you're taking all the existing fixed cost that the market has already invested in, and you're spreading it over more customers, which helps bring down those costs. So, the trick is, how do you do that in a way that also isolates any incremental additions to the peak [that] these loads are making and then appropriately allocate those costs to the new loads that are driving them?"

One area where FERC is going to be able to make a quick impact on the whole set of issues is through the RTO's compliance filings for Order 1920, which changed transmission planning and cost allocation rules.

"Customers really do value the core tenants of Order 1920 around economic regional planning to identify the best options to build transmission that meets multiple needs and get us out of this paradigm we're in right now, where we're building lots of local transmission for one-off reliability needs, or other things like that, that are raising costs to consumers," Dennis said.

The commission will have to weigh the tradeoffs between getting Order 1920 in place quickly to deal with the surging load growth and the standard practice for many large-scale rule changes, where jurisdictional utilities file multiple rounds of compliance filings, he added.

FERC has held collaborative meetings with states tied to NARUC for the past several years, but Dennis said those kinds of joint federal-state boards could be created to tackle more narrow issues than they have so far.

"FERC has a really important role in bringing together federal and state policymakers and regulators around these issues to understand where there is complication in that sort of intersection and handoff between what happens in the wholesale electricity market, what happens with the transmission grid and what happens at the retail level," he added.

Flexibility has often been discussed as a way to help data centers achieve speed-to-power, but it could bring up issues around cost allocation that would benefit from formal cooperation between FERC and the states, for example, Dennis said.

"There are opportunities to do more at a little bit more granular level than those quarterly meetings, which are very helpful as a place for them to talk about big issues," Dennis said. "But that's not the only thing that could be done with that authority." ■

EIA Charts Varying Impact of Gas Prices on Electricity Costs

Most but not All U.S. Power Trading Hubs Saw Higher Prices in 2025

By John Cropley

The U.S. Energy Information Administration *reported* average wholesale day-ahead electricity prices were higher in 2025 than in 2024 at most but not all major trading hubs in the contiguous 48 states.

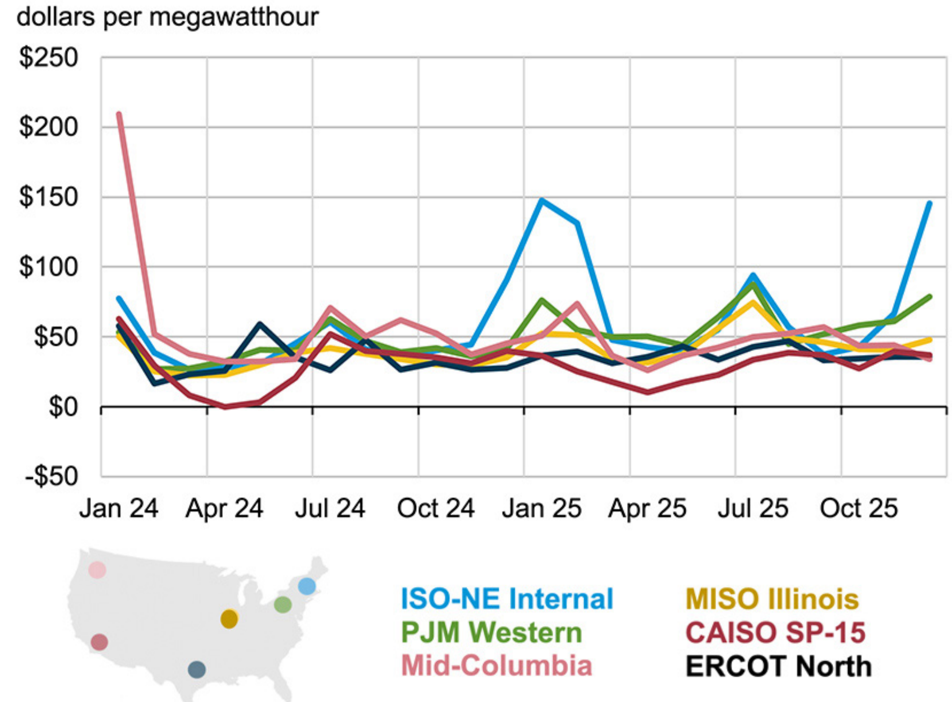
The largest decrease was $14/MWh at the Mid-Columbia hub in the Northwest. The largest increase was $29/MWh in ISO-NE.

In one of its regular "Today in Energy" posts, EIA said the national average was pushed higher largely by rising prices for natural gas, the leading source by far for U.S. electricity. Average benchmark Henry Hub spot prices were 56% higher in 2025 than the *historic low prices* seen in 2024.

This contributed to a minor shift in generation away from natural gas: Electricity generation in the 48 states increased 93 BkWh or 2% year over year, despite 2025 being one day shorter than 2024. Natural gas generation decreased 3% (53 BkWh), while coal increased 11% (76 BkWh) and solar jumped 32% (66 BkWh) to make up the difference.

The details of the shift varied by region.

In the PJM and MISO regions, total generation rose 3% (49 BkWh) in 2025 as gas generation decreased by 24 BkWh from 2024 levels, solar increased 24 BkWh and coal increased 49 BkWh.



This Energy Information Administration chart shows monthly average wholesale electricity prices at selected trading hubs. | *EIA*

In Texas, demand increased 5% (22 BkWh) in 2025; the major movers were natural gas (down 6 BkWh) and solar (up 20 BkWh).

In the Northwest, which saw a less severe winter in 2025 than in 2024, total generation decreased 4% (17 BkWh). Natural gas prices *reached historic lows* in the Northwest in 2025 amid subdued demand and ample supply from Canada, but natural gas generation nonetheless decreased 8 BkWh. Other movers were hydropower (3 BkWh higher), solar (2 BkWh higher) and nuclear (2 BkWh lower, thanks to a 65-day refueling outage). ■

ACEG Transmission Planning Report Card Gives Higher Grades for RTO Reforms

By James Downing

Recent policy changes in regional transmission planning have improved most of the ISO/RTO scores in the latest iteration of Americans for a Clean Energy Grid's Transmission Planning and Development Report Card. (See *ACEG Report Checks in on Regional Planning After Order 1920*.)

ACEC said the reforms are starting to improve outcomes in several regions, but rising demand from data centers, manufacturing and electrification are increasing the cost of delay, especially where planning processes remain incremental or reactive.

"Progress is real, but it's uneven — and demand growth means delay now carries real costs for customers," ACEG Executive Director Christina Hayes said in a statement. "Where regions have embraced proactive, long-term planning, we're seeing better results. Where planning remains fragmented, reliability risks and costs increasingly show up in household electricity bills."

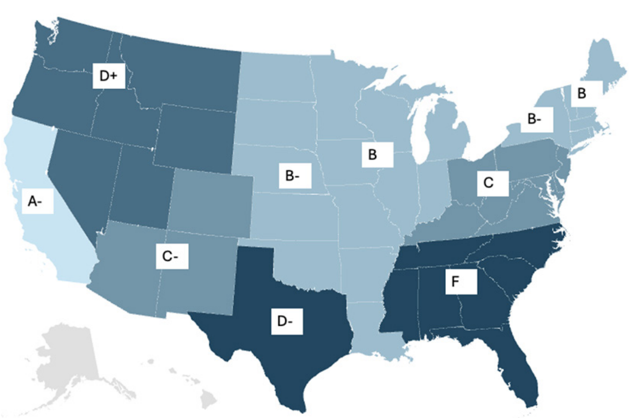
Grades assess performance at the regional level and do not assign responsibility to single institutions, instead reflecting the collective actions of utilities, regional planning organizations, states and other stakeholders. To earn top grades, regions must adopt proactive, long-term, scenario-based planning that evaluates multiple system benefits, integrates regional and interregional needs, and delivers transmission at the pace required to meet rising demand.

CAISO, MISO and SPP continue to show the benefits of proactive, long-term regional planning. SPP's Coordinated Planning Process, once approved by FERC, would be an important reform that merges transmission planning and generator interconnection planning, the report said.

ISO-NE, NYISO and PJM have shown meaningful improvement due to FERC Order 1920 compliance filings and greater engagement with states.

ERCOT got a C, with the report highlighting the Permian Basin Reliability plan to electrify oil and gas drilling and data centers, which was released in July 2024 with options for 345-Kv and a 765-Kv portfolio. The Texas PUC picked the 765-Kv option in April 2025. While Texas has seen plenty of transmission planned, the report noted it still is done in a "siloed" style, which kept it from a higher grade.

Many regions — including all the non-RTO regions — "continue to face significant gaps in both regional and interregional planning frameworks," the report said, "In these regions, transmission development often occurs through individual utility investments or ad hoc coordination rather than durable, region-scale planning processes, limiting the ability to fully capture systemwide benefits."



ACEG's report card showing how the different regions' transmission planning and development are ranked and how they have improved since 2023. | *ACEG*

The West, which is split into three regions, is meeting under the Western Transmission Expansion Coalition (WestTEC), a voluntary interregional planning process that the report called "one of the best interregional transmission planning practices in the country."

The first report card from ACEG came out in 2023 and ranked the regions before Order 1920 was issued, while the second one from 2024 did not change the grades and checked in after that order.

Why This Matters

ACEG supports FERC Order 1920, and the report card shows that most regions have moved toward the planning rules outlined in the order.

Now, the report takes the requirements from Order 1920 and adds a new focus on interregional transmission.

Load growth forecasts have changed significantly since the last report, with Grid Strategies' summary of nationwide, five-year peak load forecasts going from 24 GW three years ago to 150 GW in its most recent update. Load growth is affecting transmission development, with FERC saying it was the main driver for 1,000 miles of new facilities in 2024.

"While today's load growth can tempt a crisis-response mindset focused solely on short-term fixes, the industry must move beyond ad hoc solutions and embrace long-term regional and interregional planning," the report said. "Proactive, holistic long-term planning that also accommodates near-term needs has proven to deliver the lowest costs to consumers. It captures economies of scale that 'just-in-time' projects miss and enables high-capacity upgrades to come online ahead of demand."

The report looked at interregional planning and gave the country an overall "C-minus" that reflects continued reliance on voluntary coordination rather than a formal requirement for regions to implement interregional planning best practices capable of finding the highest value projects.

"The takeaway is not that nothing is working," Hayes said. "Transmission planning works when it's proactive, coordinated and long term. The challenge now is scaling those successes fast enough — across and between regions — to keep electricity affordable and reliable for all Americans as demand continues to grow." ■

Oregon PUC Probes PGE on Data Center Cost-sharing Proposals

Utility's Proposals Come in Wake of State's 2025 Passage of the POWER Act

By Henrik Nilsson

The Oregon Public Utility Commission questioned Portland General Electric's proposals concerning grid infrastructure cost allocation for data centers, voicing concern that the utility risked prioritizing data centers over other customers.

The Oregon PUC held the hearing under docket UM 2377, which it created in March 2025 to investigate the impact that large loads have on other customers. But with Oregon legislators passing the POWER Act in 2025, UM 2377 has become a first step in rolling out the law.

The POWER Act aims to create a separate customer category for large energy users, such as data centers, and require those users to pay a proportionate share of their infrastructure and energy costs. The law defines a large energy use facility as one that uses more than 20 MW. It applies only to Oregon's investor-owned utilities. (See *Oregon House Passes Bill to Shift Energy Costs onto Data Centers*.)

The Jan. 21 hearing focused on PGE's written testimony submitted Dec. 19.

PGE wrote that it aims to create a "durable, transparent and equitable rate structure that fairly allocates growth-related costs to the customers driving system growth, whether they are large loads such as data centers or residential demand from increasing use of air conditioning, so that each customer class pays for the costs it causes and the system benefits it receives."

Notable Quote

"I am concerned that you're articulating a pacing based on your financial situation that I'm not seeing in the tariff. And I'm not understanding how you would be able to accomplish without sort of being accused of a discriminatory behavior towards a particular customer. So, understanding that would be really helpful."

— Oregon PUC Chair Letha Tawney

Portland General Electric's operations center in Tualatin, Ore. | *Portland General Electric*

PUC Chair Letha Tawney asked for clarification on PGE's proposal, including its proposal to continue to offer an opt-in approach for grid flexibility from data centers.

Tawney asked why the utility is sticking to its voluntary flexibility approach instead of implementing a mandatory requirement to tackle potential "scarcity events" that can impact the system and other customers.

"Your proposition is the opt-in is working: We shouldn't worry about mandating something," Tawney said. "I guess I'm really concerned about grid constraints driving pricing and reliability events, truly. So, why should I have confidence that the opt-in is sufficient, as opposed to mandating, from a reliability perspective, that this flexibility has to be on the table?"

In exchange for flexibility, PGE offers data center developers "speed to market," which has resulted in "very aggressive flexibility proposals," PGE's Isaac Barrow replied.

Barrow contended that the opt-in approach has led to "significant resources [at] zero cost to the utility or any other participant, to provide the most benefit."

"There is also a technical challenge, because it is very bespoke," Barrow said. "I'm not sure what requirements you could bring forward that would allow that specific optimization of the flexibility proposals."

Tawney also asked how PGE's proposals could impact other customers' compliance with Oregon House Bill 2021, which directs the state's investor-owned utilities to reduce greenhouse gas emissions by 80% by 2030, on the path to achieving 100% GHG-free generation by 2040. (See *Clean Energy, Equity Goals to Reshape Oregon IRP Process*.)

PGE has proposed implementing a Peak

Growth Modifier (PGM), a methodology to allocate fixed generation and transmission costs to customer classes based on their contribution to peak load growth.

"I am concerned that there is a limited universe of large-scale clean energy projects that are well priced and have reasonable commercial online dates, have interconnection agreements signed and some sort of line of sight to actually energizing," Tawney said.

She asked how the PGM could address the potential of large loads consuming lower-cost generation resources while leaving residential customers with higher-cost options for HB 2021 compliance.

PGE has proposed new special contracts aimed at allowing large load customers to accelerate buildout of clean energy on the grid with the idea that it would "only be the resources that are left over from an RFP process, allowing for the best projects to go to our cost-of-service customers," according to Jacquelyn Ferchland, senior manager of rates and regulatory affairs at PGE.

Barrow added that the special contracts would address effective load carrying capability and "what is the appropriate risk allocation for underproduction as well as overproduction of the specific contracted asset."

He noted that if PGE does not serve data centers within the HB 2021 framework, other entities without decarbonization requirements may take over.

"With the demand we're seeing, if … PGE does not serve these entities within our service portfolio, within the protections of House Bill 2021, there is a strong potential that they get served by an entity that does not have decarbonization as to the greenhouse gas requirements or is not subject to the Power Act or House Bill 2021," Barrow said.

Financial Concerns

The hearing also touched on the financial pressure from buildout of resources to meet demand from data center customers.

Although tools like Contributions in Aid of Construction could alleviate some of the pressure, that might not be enough, Tawney said. She noted the risk of PGE running out of capital for other projects.

PGE keeps the balance sheet in mind, which is why the utility does not build at the speed data center customers would like, according to Ferchland. PGE's flexibility approach and special contracts aim to allow data centers to connect to the utility's system faster, she said.

"But otherwise, we are concerned about pressure on our balance sheet, and we would want to make sure that we move only as quickly as appropriate to ensure that our balance sheet remains healthy," Ferchland said.

"I am concerned that you're articulating a pacing based on your financial situation that I'm not seeing in the tariff," Tawney said. "And I'm not understanding how you would be able to accomplish without sort of being accused of a discriminatory behavior towards a particular customer. So, understanding that would be really helpful."

The commission's final order is due by April 30, 2026, according to the docket. ■

Nevada Regulators Approve SWIP-North Construction Permit

Decision Follows Idaho PUC Approval in December

By Elaine Goodman

Nevada regulators approved a construction permit for the Southwest Intertie Project-North transmission line, keeping the project on track for a 2028 operation date.

The Public Utilities Commission of Nevada (PUCN) voted 3-0 on Jan. 27 to approve the permit for the project, also known as SWIP-North.

The 285-mile, 500-kV line is being developed by LS Power subsidiary Great Basin Transmission for an estimated $1 billion. It will run from the Robinson Summit substation in eastern Nevada to Idaho Power's Midpoint substation near Twin Falls. Most of the line — 208 miles — will be in Nevada.

Mark Milburn, senior vice president of LS Power, said the PUCN permit is the final major approval needed for the transmission line.

"We continue to make steady progress on SWIP-North," Milburn said in an emailed statement. "We plan to begin construction in 2026 and be placed in operation by 2028."

SWIP-North is one piece of the larger Southwest Intertie Project corridor. At its southern end, SWIP-North will connect to the 231-mile One Nevada (ON) line that ends near Las Vegas. The ON line in turn connects to Desert Link, also known as the Harry Allen-to-Eldorado line, which ends at Southern California Edison's Eldorado substation.

NV Energy will be entitled to free rights for about 1,000 MW of SWIP-North capacity, or roughly half, according to Great Basin's November 2025 application to the PUCN. CAISO and Idaho Power will have rights to the remainder.

"NV Energy can use those capacity rights to access new generation resources, support more efficient network service operations, increase participation in Western Energy Imbalance Market (WEIM) transactions, or support wholesale wheeling transactions, which can generate additional revenue or offset current charges," Great Basin said in the application.

SWIP-North will be the northern section of the Southwest Intertie Project corridor. | *LS Power Grid*

Why This Matters

Construction of SWIP-North will complete the 576-mile Southwest Intertie Project transmission corridor, a project aimed at increasing reliability and reducing congestion in the West.

The completion of SWIP-North also will increase the capacity of the ON line, which has been limited by northern Nevada's 345-kV transmission system, Great Basin said.

The PUCN approval of the SWIP-North construction permit follows FERC approval in November 2025 for incentives and a transmission owner tariff for the project. (See *FERC Approves Incentives, Tariff for SWIP-North*.)

In December 2025, the Idaho Public Utilities Commission granted the project a certificate of public convenience and necessity.

On its website, Idaho Power, which owns 23% of SWIP-North, recapped project benefits identified by Idaho PUC staff. Those include relieving transmission congestion in the region and delaying the need for other grid projects.

Idaho Power said SWIP-North will allow it to meet winter demand by importing electricity from the Desert Southwest, where cooler weather in winter reduces electricity demand and prices.

Idaho Power emphasized that the purpose of its SWIP-North ownership is not so it can send energy to California.

"Idaho Power's ownership in SWIP-North only allows us to import energy from south to north," the company said. "Our ownership stake does not involve selling energy to California or anywhere else." ■

Pathways' ROWE Incorporated in Del., Board Search Underway

By Henrik Nilsson

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Delaware has approved the certificate of incorporation for the Regional Organization for Western Energy (ROWE), and an executive search firm has been hired to vet candidates for the organization's initial board, the West-Wide Governance Pathways Initiative's Launch Committee announced.

ROWE was incorporated Jan. 21, and the committee is preparing the next steps in establishing the organization that will assume governance over CAISO's energy markets, consultant Sarah Davis said during a Pathways stakeholder meeting Jan. 30. Next up is registering for nonprofit status and submitting the bylaws and conflict-of-interest policy with the Internal Revenue Service.

The Launch Committee's Formation Board must approve the IRS documents. The Formation Board's sole purpose is to serve in an administrative role before the initial board takes over, Davis explained. It will approve the initial board's first five members and hand off its duties to them. (See *Pathways Takes Key Step Toward Establishing ROWE*.)

"This is a big milestone," she said.

The committee has hired Lyceum Leadership Consulting to run the selection process for the initial board. Members of the committee's nine sectors have each selected a representative to serve on the Nominating Committee, which began its work Jan. 23, according to Davis.

The work will be split into two phases. The first phase includes refining the search strategy and developing the role specification for the full seven-member board. The second phase includes conducting the board search with the goal of having the first five members seated by July.

ROWE is the product of California Assembly Bill 825, which implements Pathways' "Step 2" plan to create an independent organization to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market, and authorizes the ISO and California's investor-owned utilities to join ROWE. (See *Newsom Signs Calif. Pathways Bill into Law*.)

One goal in establishing ROWE was to remove what some see as a barrier to wider participation in CAISO-run markets by ensuring they are not governed solely by officials and stakeholders in California.

The market governance structure is still being defined by a working group, Davis said.

"The work group has a few objectives," she explained. "The first is providing clarity for FERC oversight. The second is providing clarity for stakeholder processes. We're also wanting to set up a structure that we can use for a potential transition to Step 3 at some point in the future."

Step 3 in Pathways' plan includes expanding the scope of ROWE's functions and services.

"We're also being mindful of the resource commitments for these potential approaches and those constraints," Davis said.

Some areas will still be under joint authority between CAISO and ROWE, but sole authority over market policy rules will go to ROWE, Adam Schultz, CAISO manager of regional coordination, said during the meeting.

The joint areas are not related to market policy but concern certain overlapping areas such as financial and corporate issues, he clarified.

The Launch Committee seeks between $7 million and $8 million to fund ROWE's implementation costs over the next two years, Jim Shetler, general manager of the Balancing Authority of Northern California, said during the meeting. The committee is exploring funding primarily through stakeholder contributions, grants and debt financing.

"We're looking at somewhere around $750,000 to $800,000 in stakeholder contributions that we should have here in the next month or so," Shetler said.

The committee anticipates an additional $300,000 in grants, Shetler added.

With a balance of about $1.1 million, Shetler said the committee has enough money to continue operations through "[the middle] to third quarter [of] this year." The committee is working with several banks to fund the remaining portion through debt financing, he said. ■

Why This Matters

The approval of the certificate of incorporation marks another step toward establishing ROWE and ensuring wider participation in CAISO's energy markets.

Almost 9 GW of Calif. Renewables Delayed by Slowed Transmission Buildout

EDAM Resources Likely Unaffected, CAISO Says

By David Krause

California continues to add in-state renewable energy resources, but the transmission upgrades needed to bring those projects online have been lagging behind, according to the California Public Utilities Commission.

About 8.9 GW of renewable and storage resources are expected to be delayed due to transmission delays in the Pacific Gas and Electric and Southern California Edison territories, Edmund Dale, CPUC senior regulatory analyst, said at CAISO's Jan. 28 transmission development forum.

The 8.9 GW represents about 22% of the total 40.5 GW of new renewable generation and storage resources that have signed interconnection agreements in the PG&E and SCE areas.

For PG&E, about 2.5 GW of these resources are delayed due to "bundling dependencies," which are chain reactions of transmission project delays, Dale said. PG&E said the interconnection customers are responsible for resolving the transmission delays, he said.

One critical delayed transmission project in PG&E's territory is the Vaca-Dixon Substation 230-kV circuit breakers 442, 452 and 462 project. About 450 MW of new capacity is delayed due to this project's lag, with an additional 900 MW at risk.

Material problems are a primary cause of transmission delays, with a supply chain issue resulting in an 11-month delay on PG&E's Gates 230-kV Reactors Bus E-F transmission project, affecting 2 GW of resources. To address the delays, PG&E will shift material from another project to the Gates project, Dale said.

Financing and project redesign delays could also significantly affect renewable and storage resource projects in PG&E's territory, Dale added.

In SCE's territory, long lead-time materials, such as circuit breakers, transformers and specialized steel structures, are forecast to delay 4.5 GW of new resources, with an additional 2 GW of resources at risk of delay.

To alleviate some of these delays, participating transmission owners should consider allocating more time and other resources to determining more realistic in-service dates and project costs, Dale said.

CAISO is in frequent and close coordination with the CPUC and the transmission owners about transmission project delays, CAISO spokesperson Jayme Ackemann told *RTO Insider*.

"Delays do not typically result in changes to the transmission studies or approvals, per se, but such delays are considered in the generator interconnection and deliverability allocation processes," she said.

The ISO does not anticipate impacts to available resources in EDAM, Ackemann added.

Transmission project delays are now tracked per the requirements of California Senate Bill 1174, passed in 2022. The law requires transmission facility owners to submit a report to the CPUC that shows changes to previously reported in-service dates of transmission and interconnection facilities that are necessary to provide transmission service to certain renewable or energy storage resources.

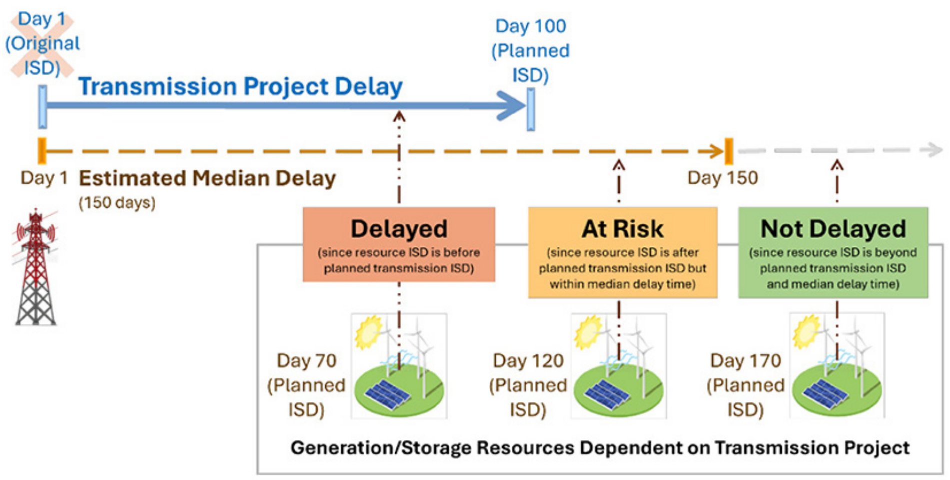
In November 2025, the CPUC detailed transmission delays in an annual *report*. It showed 449 delayed transmission projects with associated renewable generation or storage resources.

San Diego Gas & Electric said it did not have any delayed transmission projects with associated renewable and storage projects.

CPUC staff reviewed SDG&E's data and "determined it to be incomplete and inaccurate" and requested updated corrections to SB 1174 data from SDG&E, which SDG&E provided, the report says. However, CPUC staff determined that the updated data was "still not sufficient" because SDG&E did not provide data for its in-development transmission projects and provided incorrect original in-service dates, the report says. ■

Why This Matters

California energy officials have forecasted large increases in electricity demand in the coming years, which makes connecting new resources to the grid important to meet the added consumption.



This graphic shows how renewable resource delays are counted. | *CPUC*

BPA Provides More Details on $5B in Tx Projects

Stakeholders Voice Concern over Tax Credits, Coordination Efforts

By Henrik Nilsson

> **Why This Matters**
>
> BPA hopes the $5 billion in transmission projects will help the agency meet the changing energy landscape and address growing loads from big industrial electricity consumers.

The Bonneville Power Administration provided updates on the agency's $5 billion in transmission projects as some stakeholders asked about sunsetting of tax credits and coordination efforts with other developers in the West.

BPA staff discussed the agency's Grid Expansion and Reinforcement Portfolio (GERP) during a Jan. 27 meeting. GERP consists of more than 20 proposed transmission line and substation projects. The initiative, previously called Evolving Grid, aims to improve transmission and reliability in the Northwest, according to the *agency's website*. (See *Stakeholders Seek More Details on BPA's 'Evolving Grid' Projects*.)

BPA launched GERP in two phases in 2023 and 2024.

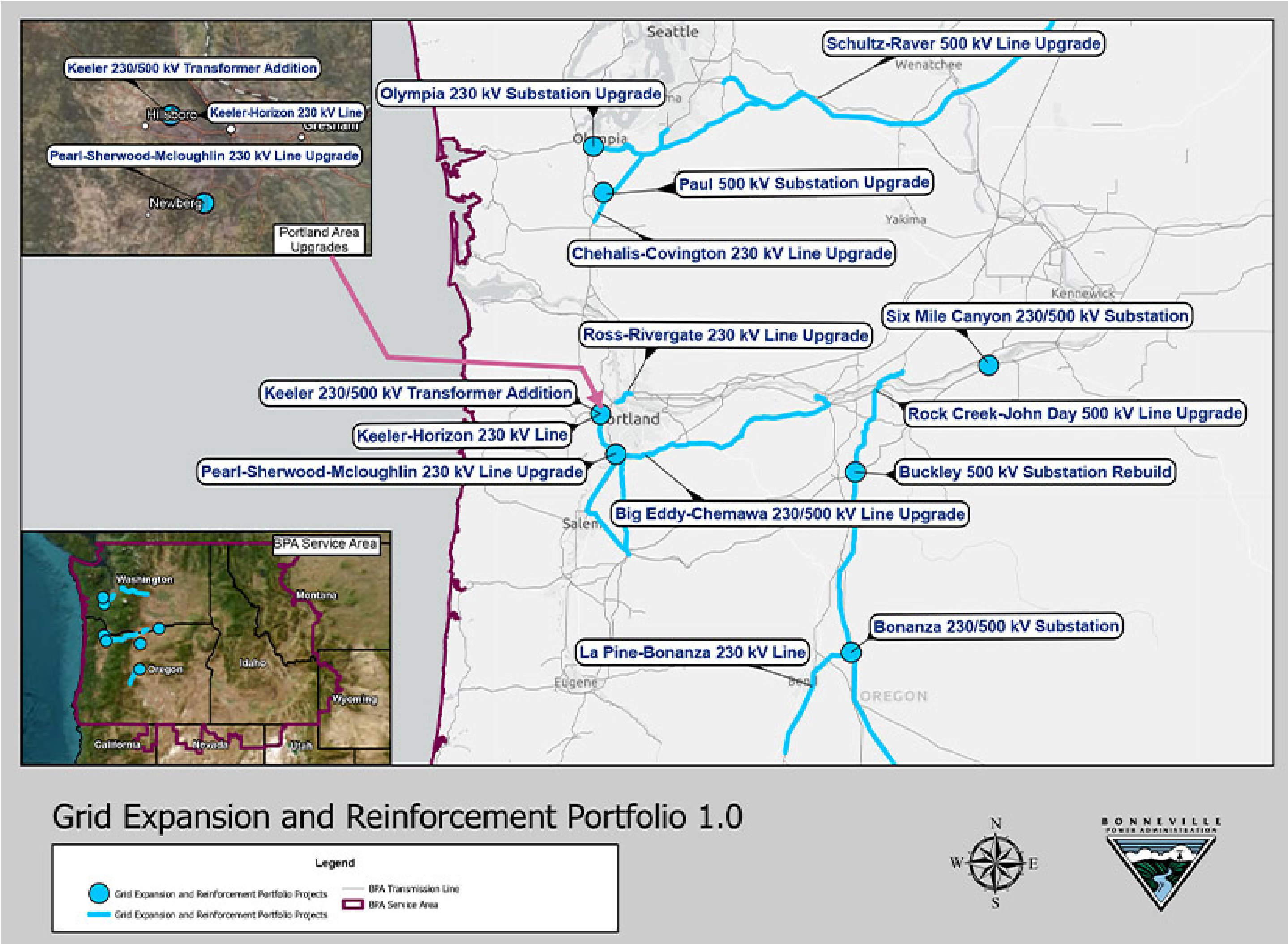
GERP 1.0 includes 10 proposed projects focused on 363 miles of transmission lines at a preliminary cost of $2 billion. It includes upgrades, rebuilds and improvements to existing facilities, as well as two new substations and one new transmission line.

The projects are all proposed as they have not undergone an environmental assessment under the National Environmental Policy Act (NEPA), according to BPA's Eric Orth.

Orth said he does not anticipate many NEPA challenges because many of the GERP 1.0 projects concern upgrades to existing facilities.

"They're not brand-new lines going through new territory," Orth said. "We will do our due diligence when it comes to NEPA, but I don't anticipate any big challenges with these lines or substation projects."

The largest upgrade under GERP 1.0 is



The largest upgrade under BPA's GERP 1.0 initiative is the Big Eddy to Chemawa line. | *Bonneville Power Administration* the replacement of a 91-mile, 230-kV line with a 500-kV line between BPA's Big Eddy substation and Pearl substation. The upgrade has a preliminary estimated cost of $670 million and an estimated completion by 2033.

Orth said staff are scoping the project.

"We are well on our way," Orth said. "We've got a good plan of service, and we're currently putting together plans to solicit the project this summer for an engineer, procure, construct contract. And so that's exciting. That's a big step. Essentially … the project will be at a 30% design, and we will bid that out competitively to a pool of contractors to finish the project."

Many of the GERP 1.0 projects have an estimated completion date after Dec. 31, 2029, when federal tax credits for solar and wind projects are set to expire, according to Alex Swerzbin, vice president of power marketing and transmission at NewSun Energy.

"If these generating projects aren't energized, they're going to lose out on your tax credits, which could be 30, 40% tax rate and value of the project," Swerzbin said.

Customers can help by coordinating with BPA "as projects develop through scoping and design. Many of the schedules are tied to how long it takes to procure some of the materials," Orth said.

BPA is working on "on ways to condense schedules," Orth said. "But I think the question is a good reminder for us to maybe go back and look at which projects are tied to some renewable generation interconnection requests and see if we can do anything with the timing."

GERP 2.0

GERP 2.0 includes 13 proposed projects with a preliminary projected cost of $3.9 billion. BPA aims to complete GERP 1.0 projects in the next five to six years, while GERP 2.0 projects have a longer timeline. Many of the 2.0 projects build on 1.0 upgrades, BPA's Matt Hagensen said.

One major GERP 2.0 project is the Lower Columbia NOB initiative, a three-part effort aimed at improving connectivity from the lower Columbia region to the Nevada-Oregon border with 500-kV transmission lines and a new substation near the border.

The project has a preliminary estimated cost of $1.9 billion with an estimated completion by 2035.

"It'll help create more interregional connectivity," Hagensen said about Lower Columbia NOB. "We do have some joint studies going on with some southern partners in Nevada that would build up to that station. And so really creating that opportunity and that resource diversity between the Northwest and the Southwest."

Fred Heutte, senior policy associate at the NW Energy Coalition, asked about coordination with other developers, pointing to PacifiCorp's Blueprint South project, a new 180-mile line in southern-central Oregon.

Hagensen said BPA coordinates with other stakeholders through regional planning to assess how projects interact.

Heutte noted "these are multibillion-dollar projects," saying "we kind of got to get it right."

Western regional assessments focus primarily on east-west connectivity, according to Heutte.

"I think the north-south configuration is something that really needs more attention," he said. "So, just to say, this is a very interesting project. It has lots of big pieces and there are other forces at play here. And just to encourage Bonneville to provide more information about the discussions and studies that are being done, and again, more context, because this is a very big deal." ■

CPUC Portfolio Shows Offshore Wind Delayed up to 6 Years

Proposed Decision also Calls for Additional Reliability Resources

By David Krause

California's two large offshore wind projects could be delayed by up to six years due to recent federal policy actions, a California Public Utilities Commission administrative law judge said Jan. 14.

The Morro Bay offshore wind project is now forecast to come online by 2036 rather than 2032, CPUC ALJ Julie Fitch said in a *proposed decision* on electric integrated resource planning and procurement. A second project, in Humboldt County, is projected to come online by 2041 rather than by 2035.

The delays are "reasonable and should be adopted as the recommendation for CAISO's 2026-2027 Transmission Planning Process," Fitch said in the proposed decision.

The forecasted delays are part of the CPUC's latest electricity and sensitivity resource portfolios, which the commission sends to CAISO for inclusion in the TPP. The ISO uses each TPP to determine whether additional transmission projects are needed in its region.

Although federal policy will affect California's offshore wind projects, regardless of these policy changes, "it is important to note that offshore wind is not optimally selected in least-cost modeling," the proposed decision says.

Numerous parties cautioned against delaying transmission planning that would support offshore wind in Humboldt County beyond 2036.

Why This Matters

Offshore wind development has slowed to halt in much of the U.S. because of federal policy changes, and California is now seeing some ripple effects from those moves.

Environmental Defense Fund told the CPUC that the offshore wind industry is "at an inflection point" and that delaying the planned projects' online dates could cause a "significant chilling effect that would not be in the interest of ratepayers," the proposed decision says.

CalCCA recommended the CPUC maintain the amount of in-state and offshore wind in previous TPP portfolios and limit out-of-state wind. And Humboldt County representatives questioned why the North Coast offshore wind project is delayed by six years while Central Coast is delayed by only four years, the proposed decision says.

Many other stakeholders expressed concern that the state is planning to rely heavily on new out-of-state solar development when in-state resources, such as offshore wind, would be preferable, the proposed decision says.

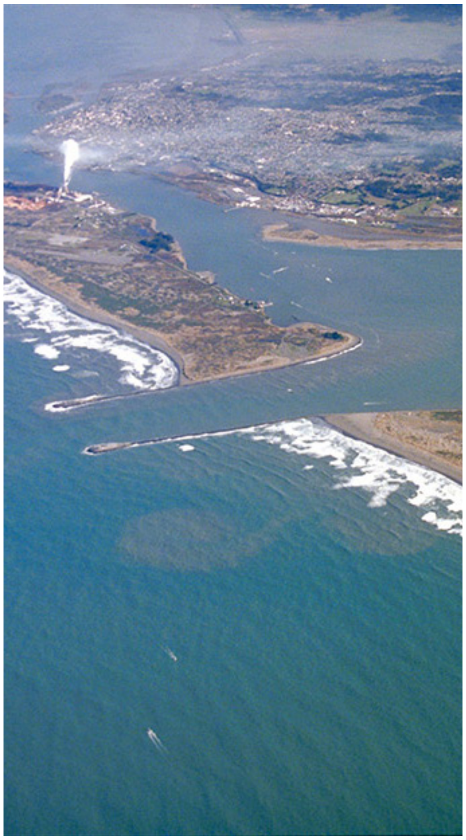
In October, the California Energy Commission approved $42 million for five offshore wind projects at California ports. (See *CEC Approves 5 Offshore Wind Projects at California Ports*.) In November, the CEC added $9.2 million more for research on deepwater HVDC transmission. (See *'There's Room for Everybody': California Ports Prepare for OSW Development*.)

The current TPP base case for 2025-2026 includes 4.5 GW of new offshore wind capacity.

Additional RA Procurement Proposed

Under the proposed decision, load-serving entities would need to procure an additional 2,000 MW of net qualifying capacity (NQC) by 2030 and 4,000 MW more by 2032.

This additional procurement is the result of the CEC's 2024 Integrated Energy Policy Report demand forecast, which showed an increase in demand due to data center growth and vehicle and building electrification, and a decrease in the number of people who plan to install behind-the-meter solar and storage units.



Humboldt Bay in Northern California | *U.S. Army Corps of Engineers*

In the CPUC's analysis, Diablo Canyon Power Plant (DCPP) was modeled as offline in all years, and all combined heat and power plants were kept online. While it is "likely that DCPP will be online through 2030 in reality," the proposed decision says the CPUC's model follows the requirements of California's *Senate Bill 846*, which extended the operating life of the nuclear plant.

Energy storage resources can account for only up to 50% of the additional NQC amounts under the proposed decision.

The "real winner" of the procurement order is geothermal energy, Farhad Billimoria, representative of Aurora Energy Research, told *RTO Insider*. With offshore wind development in the state facing continued delays, community choice aggregators will again be forced to scramble for clean firm capacity, leaving geothermal as the only realistic, if still costly, option, Billimoria said. ■

CAISO Issues 1st Report Under Independent Governance Law

ISO Listed Various Activities in Anticipation of Market Changes

By Henrik Nilsson

CAISO released its first mandatory report under the California assembly bill that paves the way for an independent regional organization to assume responsibility over the ISO's energy markets.

Under AB 825, CAISO must submit an annual report to the California governor and Legislature about the ISO's various initiatives and decisions. Gov. Gavin Newsom signed the law in September 2025, and CAISO submitted the first report to the Legislature on Feb. 1, according to a news release.

"The ISO appreciates the commitment by Gov. Newsom and the Legislature to support independent governance of the real-time and day-ahead regional electricity markets that benefit consumers across the West," CAISO CEO Elliot Mainzer said in a statement. "We look forward to continuing to work with the state and stakeholders throughout the region to help make that new governance framework a reality."

AB 825 allows for the creation of an independent organization to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market. The bill authorizes CAISO and California's investor-owned utilities to join the organization.

Designed by the West-Wide Governance Pathways Initiative, the organization was recently incorporated in Delaware as the Regional Organization for Western Energy. (See *Pathways' ROWE Incorporated in Delaware, Board Search Underway*.)

In the AB 825 report, CAISO listed activities from the past year, including federal tariff proceedings, policy initiatives, decisions, market activity and transmission planning.

Among the more than 40 tariff changes listed by CAISO were proposed efforts to reduce the generator interconnection queue and a FERC decision delaying the sunset date on the WEIM's Assistance Energy Transfer feature, which allows CAISO to limit market transfers into and out of BAAs that have insufficient supply or ramping capacity. (See *CAISO Looks to Remove Stagnant Projects from Interconnection Queue* and *FERC OKs Extension of WEIM Assistance Energy Transfer Feature*.)

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Why This Matters

CAISO's Feb. 1 report was the first the ISO will be required to submit to the state each year until it transitions its markets to independent governance in 2028.

The report lists suggested enhancements to congestion revenue rights, initiatives to address reliability needs and uncertainties between the day-ahead and real-time market, new resource adequacy rules, storage enhancements and greenhouse gas coordination, among other initiatives.

CAISO is also working to "extend participation in the day-ahead market to the [WEIM] entities in a framework similar to the existing WEIM approach for the real-time market. EDAM will improve market efficiency by integrating renewable resources using day-ahead unit commitment and scheduling across a larger geographic area," according to the report.

The report notes that CAISO intends to seek approval from its Board of Governors for its 2025/26 transmission plan in May 2026.

Under the 2024/25 transmission plan, CAISO received approval for 31 projects valued at $4.8 billion, 28 of which are for reliability purposes for $4.6 billion. The ISO estimated it needs 76 GW of additional capacity to meet increasing building electrification and electric vehicle loads. (See *CAISO Approves $4.8B Transmission Plan to Support 76 GW of New Capacity*.) ■

ERCOT Leaned on Mobile Gens, RMR Unit During Storm

Texas PUC Approves Firm Fuel Criteria

By Tom Kleckner

ERCOT says Texas' 15 mobile generating units and a reliability-must-run unit all played an "*important reliability function*" during the Jan. 25-27 winter storm, the state's first major cold-weather event since 2021's disastrous Winter Storm Uri.

Grid operator staff told the Texas Public Utility Commission during its Jan. 29 open meeting that CPS Energy completed repairs to its Braunig Unit 3 before the storm arrived and that it was committed throughout the event.

Dan Woodfin, ERCOT's vice president of system operations, told commissioners that Unit 3 provided "necessary support" to relieve overloads in the San Antonio region after a large unit in Central Texas tripped Jan. 25. The trip caused "brief exceedance" on the South Texas export constraint and post-contingency overloads on some transmission lines between the region and Houston, necessitating a localized transmission emergency declaration that lasted about 13 hours.

Woodfin said the grid operator also committed the mobile generating units that were moved from Houston to San Antonio in 2025 to provide reliability support for the South Texas constraint. The constraint was binding throughout the storm, he said.

"The combination of these actions was sufficient to operate the system reliably until the large unit came back on" Jan. 26, Woodfin said.

CPS had intended to retire the 55-year-old gas unit in 2025, but ERCOT determined that it was needed to address the South Texas constraint. The RMR is the grid operator's first since 2016, when it entered into an agreement with NRG Texas Power over a previously mothballed gas unit near Houston. (See "Braunig Outage to End in December," *ERCOT: New Ancillary Service Key to Resource Adequacy*.)

Why This Matters

The Jan. 25-27 storm was Texas' first major winter challenge since February 2021, when hundreds of Texans died during a dayslong outage.

"Kudos to ERCOT and to everyone involved for how the grid played out during this storm," PUC Chair Thomas Gleeson said. "I think everyone resoundingly said this was a success [in] probably the most difficult storm we've had to endure since Winter Storm Uri. Everyone should be commended for the work done on this."

ERCOT navigated the storm without resorting to calls for conservation, issuing energy emergency alerts or suffering systemwide power outages. Demand peaked at nearly 76 GW on Jan. 26, far short of early projections of 83 GW. Staff said the state's cloud cover and closures of businesses and schools helped reduce demand.

"In summary, *ERCOT successfully managed* the Texas electric grid through this cold-weather event. As always, we will continue to learn from this event to improve our tools and processes going forward," Woodfin said.


ERCOT's Dan Woodfin briefs the Texas PUC on the grid operator's response to the January winter storm. | *AdminMonitor*

FFSS Criteria Approved

The commissioners approved staff's *proposal* establishing the criteria for participation in ERCOT's Firm Fuel Supply Service (FFSS) program and the grid operator's requirements to implement it, a result of a law passed during the *2021 legislative session* in Uri's aftermath (*58434*).

The rule codifies requirements to procure FFSS during natural gas curtailments and cold-weather events. Staff identified three categories of resources eligible to provide the service: on-site, resource-controlled and contractual off-site. The latter expands the program, although its budget remains unchanged at $54 million.

Jeff McDonald, the Independent Market Monitor's director, objected to the inclusion of gas-fired resources but said he understood that the 2021 storm "precipitated a need on the reliability side." He said he was more concerned that FFSS, other ancillary services and residential demand response are all out-of-market actions that affect the ERCOT energy-only market's reliance on shortage pricing to incent investment.

"They suppress the shortage-pricing mechanism from being able to adequately signal that there's shortages," McDonald said. "Therefore, there's less revenue in the market. Therefore, you're going to have delayed or reduced new investment.

"I would like to see these programs be diminished over time and more focus placed on the kernel of resource adequacy for ERCOT, which is shortage pricing," he added. "I do understand the need after Uri. Cracks were exposed that needed to be filled. Enough time has passed now that I think it's time to … focus more on in-market price signaling to provide reliability services to fill those cracks."

Gleeson said he agreed with McDonald about the need to allow the market to provide revenues from scarcity, but he also said the rule makes sense "where we sit right now."

"I think what you'll see is continued discussion about that and the right timing to actually implement those changes," Gleeson said.

Batch Zero's Phased Study

ERCOT will conduct its first "batch" study of large load interconnection requests in two phases, Jeff Billo, vice president of interconnection and grid analysis, told the PUC.

The grid operator has already proposed a "Batch Zero" process to address the 232 GW of interconnection requests from AI facilities, cryptocurrency miners and other large loads. Now, that batch's first phase, or Phase A, will be limited to large loads that want to be energized early in 2027. Projects in that batch will undergo an abbreviated version of the Batch Zero study. (See *ERCOT Again Revising Large Load Interconnection Process*.)

A longer, full Phase B study will be for projects with longer timelines. It would begin in August and be completed early in 2027. Even then, the loads will have to pass ERCOT's quarterly stability assessment five to eight months before they are energized.

"We need to do an operational assessment before those loads connect … to see if there's anything that has changed since the studies were performed and see if we need to implement any sort of operational constraints to make sure that we know where the constraints are on the system," Billo said.

The Batch Zero study will serve as a foundation for the other batch studies that follow every six months, beginning in the first quarter of 2027, Billo said. ERCOT will share the draft criteria for large load requests during a *Feb. 3 workshop*.

Responding to Federal Issues

Staff *told* commissioners that the PUC has joined the ballot pool for NERC's Long-Term Planning Energy Assurance project (*2024-02*), allowing it to participate in future votes and comment windows (*54987*).

NERC has scheduled a workshop and meetings Feb. 17-19 to discuss concerns and start drafting revisions to the proposed standard, which has drawn pushback from utilities over a requirement to create corrective action plans. The standard failed to pass a first round of voting, garnering only 17.8% support.

PUC staff plan to return to the commission with comments to file in the proceeding.

"I think that's the right course of action. I think corrective action plans seem out of scope for" NERC, Gleeson said.

The PUC has already adopted a reliability standard that sets criteria for frequency, duration and magnitude of loss-of-load events. (See *Texas PUC Sets Reliability Standard for ERCOT*.)

Following a closed session, the PUC voted to file *amicus* briefs supporting FERC in two dockets before the D.C. Circuit Court of Appeals: Clean Wisconsin, the Natural Resources Defense Council and the Sierra Club's appeal of the commission's approval of MISO's Expedited Resource Addition Study process (*25-1264*), and Advanced Energy United, Advanced Power Alliance, American Clean Power Association and Solar Energy Industries Association's challenge to SPP's Expedited Resource Adequacy Study (*25-1265*). ■

British Grid Operator to Highlight ERCOT Innovation Summit

By Tom Kleckner

ERCOT says Fintan Slye, CEO of Great Britain's National Energy System Operator, will join ERCOT CEO Pablo Vegas to kick off the Texas grid operator's third annual Innovation Summit.

Slye leads the publicly owned NESO, which manages Great Britain's electric system and is responsible for planning the nation's energy systems and markets. He has held leadership positions with the country's Electricity System Operator and EirGrid, Ireland's transmission system operator.

"NESO is at the heart of Great Britain's energy system, and innovation is at the heart of everything we do," Slye said in a statement. "At NESO, we are always looking to use innovation to help drive value for consumers and improve security of supply."

He said it is "brilliant and timely" to participate in the summit and to collaborate with U.S. industry peers on grid upgrades, new data center demand, and other learnings and solutions that can benefit Great Britian's energy system. The *2026 Innovation Summit*, to be held March 31 at Kalahari Resorts and Conventions in Round Rock, Texas, will bring together industry stakeholders and thought leaders to share technological advancements and innovative solutions that advance grid transformation in Texas and beyond.

"Collaboration with our industry peers in the U.S. and across the globe is essential as we work toward building more resilient and intelligent solutions for rapidly evolving grids," Vegas said.

The grid operator *announced* in September a *Grid Research, Innovation and Transformation (GRIT)* initiative designed to improve industry collaboration through expanded shared research and technology prototyping. The program's technology initiatives focus on a range of areas, including smart controls for distributed energy resources, machine learning models to improve power flows and improvements to large load modeling.

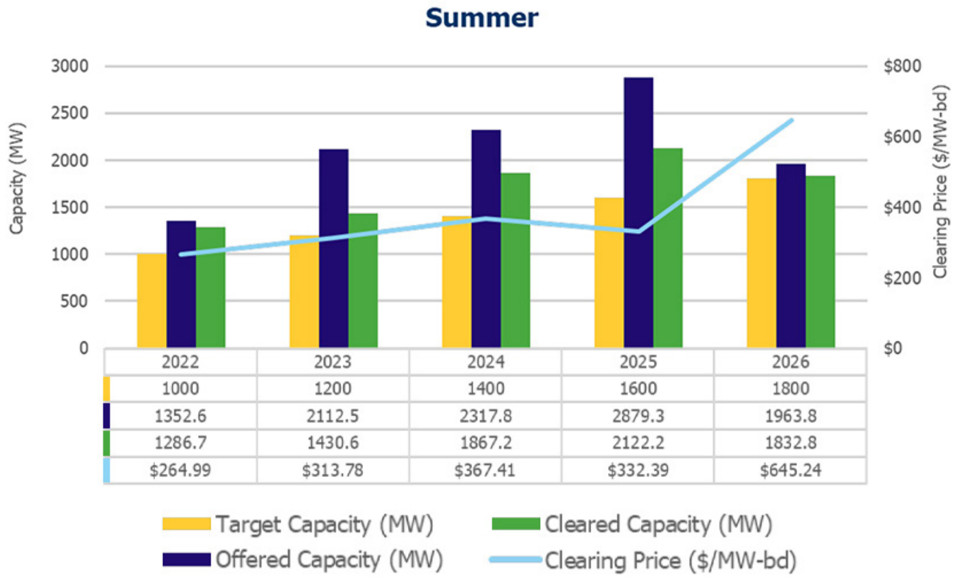
ERCOT says between 850 and 950 participants attended each of the first two summits, either in person or virtually.

PJM CEO Manu Asthana highlighted the 2025 summit, also held in Round Rock. ■

Venkat Tirupati, ERCOT's vice president of DevOps and grid transformation, opens the 2025 Innovation Summit. | *ERCOT*

IESO: Few Capacity Downgrades from Performance Adjustment Factor

By Rich Heidorn Jr.



IESO year-over-year capacity auction comparisons for summer. | *IESO*

IESO downgraded less than 100 MW of capacity for November's auction in the first application of its Performance Adjustment Factor (PAF) in both the winter and summer seasons.

The PAF ensures the ISO procures only capacity that has been confirmed by testing.

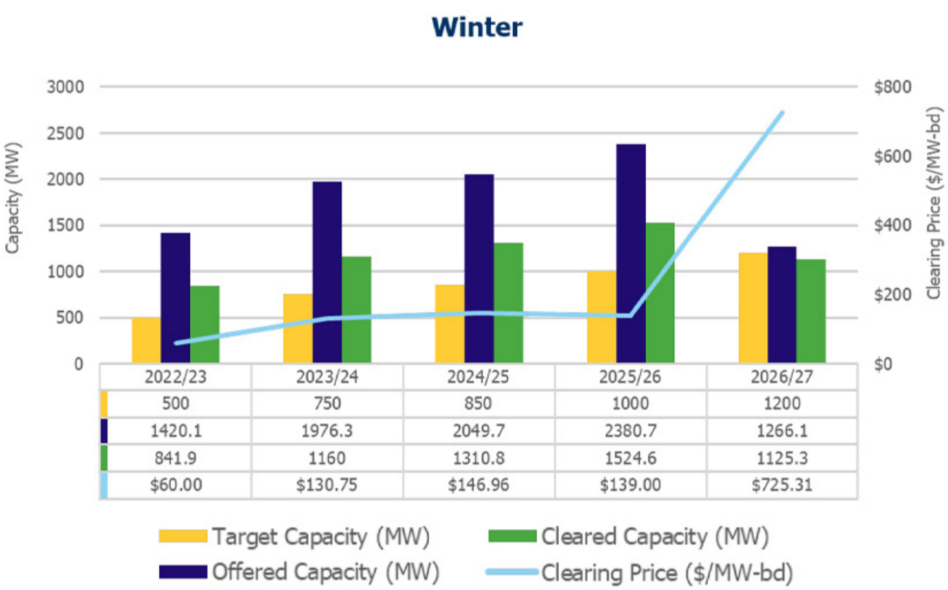
"It really was a small number of megawatts that ended up being derated because of the [PAF] … less than 100; probably less than 50 megawatts. But it was a very small amount," Laura Zubyck, IESO's capacity auction supervisor, said during a Jan. 29 *engagement*. "We've seen good performance in our capacity tests, and so we rarely derate."

Clearing prices hit a record $471/MW-day for summer 2026, nearly double the $243 from 2024, and $530/MW-day for winter, more than five times the previous $102. (See *Big Jump in Ontario Capacity Prices Signals Tightening Supplies*.)

IESO's Paulo Antunes said the results reflected short-term changes in supply combined with a 200-MW increase in the target capacity. The auction cleared 1,832.8 MW for summer 2026 and 1,125.3 MW for winter 2026/27.

IESO cleared no imports from New York, a loss of 200 to 300 MW compared with previous years. Antunes said. In addition, about 200 MW of Ontario-based generation that had previously participated in the auction instead signed contracts with the ISO under its second medium-term procurement.

"The remaining available supply in the market was not enough to offset the combined impact of these two factors," said Antunes, who also noted the impact of increasing electricity demand and ongoing nuclear refurbishments.



IESO year-over-year capacity auction comparisons for winter | *IESO*

Virtual hourly demand response resources made up the largest share of cleared capacity, representing almost 41% in summer and 60% in winter. (See related story, *IESO, Stakeholders Ponder Changes to Hourly DR*.)

The largest increase in cleared summer capacity came from system-backed imports, which accounted for almost one-third of cleared capacity.

The increase was largely enabled by increasing the Hydro-Québec import limit from 400 MW to 600 MW.

Generation-backed imports, in contrast, declined.

The 2025 auction also showed a narrowing gap between offered and cleared capacity. "In previous years, the gap has been much bigger, and this is resulting in an upward pressure on price," Antunes said.

Julien Wu, of Brookfield Renewable, thanked the ISO for providing more detail on auction results than in past years but asked officials to provide still more, including information on the technology types that experienced derates due to the PAF.

"The more information we have, the easier it is for us to make scheduling and trading decisions," he said. ■

IESO Seeks Input on RFP for 3rd Toronto Transmission Line

By Rich Heidorn Jr.

IESO is seeking stakeholder input on its first competitive transmission solicitation: a $1.5 billion HVDC line under Lake Ontario that will become the third major supply line for Toronto.

The ISO recommended the 65-kilometer, 900-MW Toronto Third Line (TTL) in September 2025, saying it would be more "future proof" than two cheaper options. Planners say the line, which was approved by Ontario's Minister of Energy and Mines in January, is needed to meet a potential doubling of Toronto's electricity demand by 2050. (See *Ontario OKs Underwater HVDC Line to Toronto*.)

In July, IESO opened enrollment in its Transmitter Selection Framework (TSF) Registry, a prequalification mechanism for competitive procurements. (See *IESO Removes Credit Requirement for Transmission Registry*.) As of Dec. 12, two transmission companies — Fortis and Emera — were approved for listing in the *registry*.

The ISO's tentative procurement plan, outlined in a Jan. 28 stakeholder *engagement*, calls for closing the TSF registry in the fourth quarter and opening the request for proposals in the first quarter of 2027, with proposals due in the third quarter and an award in the fourth. The projected in-service date is 2037 "or sooner," IESO *said*.

Electricity demand is expected to exceed the capacity of the two transmission lines currently supplying Toronto by 2038. Closure of the 550-MW gas-fired Portlands Energy Centre would accelerate that "reliability need" to 2034.

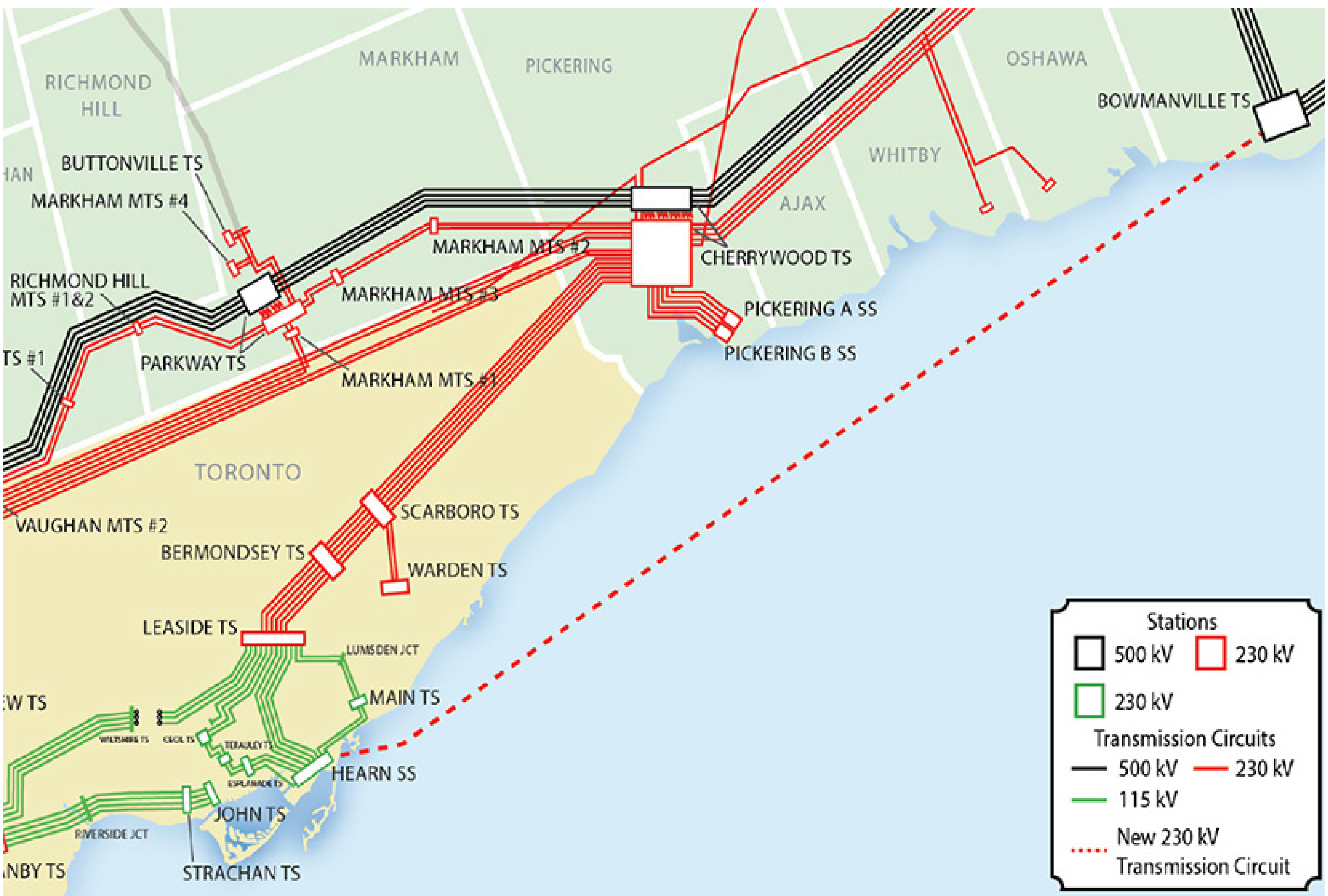
Why This Matters

Electricity demand is expected to exceed the capacity of the two transmission lines currently supplying Toronto as soon as 2034.

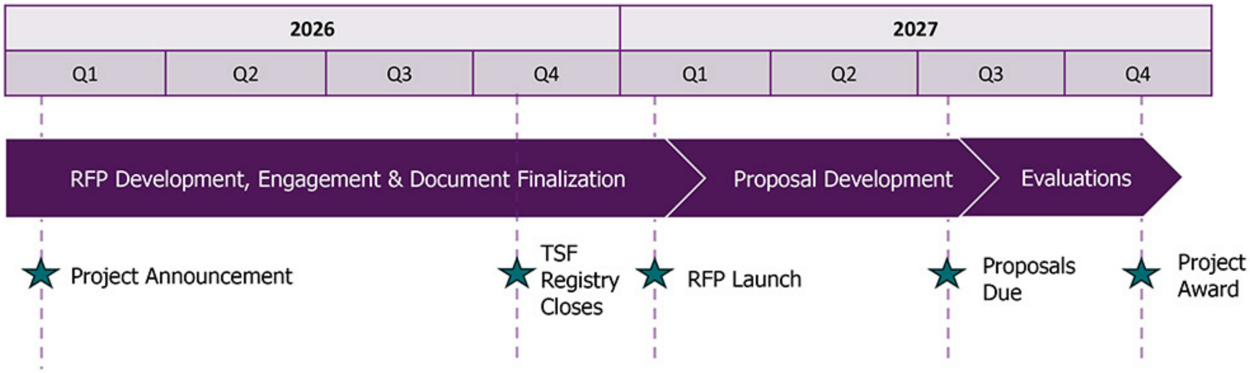
Design Elements

Although the TTL will be the first HVDC and underwater line in Ontario, similar projects have been built elsewhere in Canada, as well as in the U.S. and Europe.

Under IESO's standard competitive model, the winning bidder would receive a contract covering all costs for the trans-



The Toronto Third Line will span 65 kilometers from the Bowmanville substation to an HVDC injection point at the Hearn substation. | *IESO*



Tentative procurement plan for the Toronto Third Line | *IESO*

mission line's first 10 years of commercial operation, with the contract transitioning to traditional rate regulation under the Ontario Energy Board in Year 11.

But IESO said the TTL's "unique technical, environmental and delivery risks [are] not well suited to a contractual model that only allows limited cost adjustments over a longer contract term."

The ISO said schedule commitments and costs that proponents can reasonably scope and price will be subject to an IESO contract. Uncertain or "externally influenced" costs will be subject to review by the OEB under its "just and reasonable" prudency standard. The OEB's cost of capital parameters and deemed capital structure also will apply.

"We are seeking input on potential appropriate cost adjustment mechanisms to reduce unnecessary risk premiums while protecting ratepayer value," the ISO said.

IESO also asked for comments on how prescriptive its technical requirements should be at the RFP stage.

Experience, Indigenous Engagement

Bidders will be required to have experience developing, constructing, operating and mitigating environmental impacts of underwater transmission projects as well as engaging with Indigenous communities, "including undertaking rights-based consultation within treaty and traditional territories."

IESO is seeking feedback on how to define experience and whether it should be demonstrated at the corporate level or through individual team members, including partners and subcontractors.

All bidders will be required to submit an Indigenous Engagement & Participation Plan (IEPP) to "ensure Indigenous communities are provided with meaningful opportunities to participate" in the project. IESO's evaluation of the IEPPs will include proposed equity participation structures and non-equity opportunities, including employment, contracting, supply chain participation, training and scholarships.

It asked for input on how it should weight the importance of equity and non-equity participation and how it can ensure early Indigenous community engagement without "inundating communities with requests for engagement from prospective bidders."

"We're not setting up a system that rewards who can get a signature [from communities] first," IESO's Andrew Lee said.

The Ministry of Energy and Mines says dozens of Indigenous communities have rights or interests in the project area, including the Mississaugas and Chippewas. The ministry's delegation letter will identify the Indigenous communities to be consulted and the level of consultation.

Aaron Detlor, a lawyer for the Haudenosaunee Development Institute, which represents the Haudenosaunee Confederacy Chiefs Council (HCCC) in the development of lands within areas of Haudenosaunee jurisdiction, questioned the legality of the IESO's RFP.

"We haven't had any engagement with the Crown on this RFP process, and that itself is a breach of the honor of the Crown," he said. "You've excluded all kinds of Indigenous people from even bidding on this. So, what you're doing is you're creating an RFP process to exclude Indigenous people."

Amy Gibson, manager of the ministry's Indigenous Energy Policy unit, said the ministry has not delegated any consultation duties to IESO and is "directly consulting with communities," including the HCCC.

The ISO is "separately having early engagement around design features because of the timelines associated with this project, but we have not given the direction to the IESO yet on the specific criteria that they will proceed with. So, this is information gathering," she said.

Detlor declined officials' offer to continue the discussion offline.

"I've written you dozens of times on different IESO hearings and meetings, and I've never gotten an answer back," he said. "I've written to the ministry, and I've written to IESO … 60 times."

Engagement Sessions

IESO plans to hold engagement sessions on the procurement every two or three months through 2026, with a March session on RFP and IEPP design considerations.

The ministry is seeking comments on the RFP until Feb. 21 through an Environmental Registry of Ontario *posting*.

Comments on the Jan. 28 engagement are due Feb. 18 to *engagement@ieso.ca* using the feedback form posted on the engagement *webpage*.

IESO is pausing engagement on the competitive process while the TTL procurement is under development. However, it continues to develop recommendations for upcoming transmission projects and determining which ones would also be suitable for competitive procurements. ■

IESO Holds Firm on Hydro Exclusion, Reserve Price in Long Lead-time RFP

By Rich Heidorn Jr.

IESO officials held firm on excluding hydro redevelopment projects from the ISO's Long Lead-Time (LLT) procurement despite objections from potential bidders at a Jan. 28 *engagement* session.

Officials also attempted to assuage concerns about the use of confidential reserve prices to control costs.

The ISO created the LLT procurement for resources that require longer planning cycles than the four-year lead times in the pending Long Term 2 (LT2) procurement. IESO plans to seek 600 to 800 MW of capacity from storage resources and up to 1 TWh of energy from hydro resources requiring at least five years of lead time. (See *IESO Drops Termination Option for Long Lead-time RFP*.)

The energy stream of the LLT request for proposals will be open to new-build hydroelectric facilities with a nameplate capacity of at least 1 MW that do not include pumped storage. The ISO said it will not permit bids from hydro redevelopment or expansion projects, despite proponents' claims that such additions may also require longer design and construction cycles.

Stephane Boyer, of FirstLight Power, said he did not understand the ISO's rationale for excluding hydro expansions, which he said would be unable to compete against wind and solar projects in IESO's long-term procurements.

"Why not give the opportunity to bid in [and] get the most cost-competitive hydro you can get in the earlier window that is currently open?" he asked.

IESO officials said hydro expansions and redevelopments should seek 20-year contracts under the upcoming LT2 procurement because they can be developed in less than five years and don't require the 40-year contracts in the LLT solicitation.

Boyer and Paul Norris, president of the Ontario Waterpower Association, said ratepayers would benefit from the longer contract terms. "We're artificially eliminating … the participation of some

Why This Matters

The initiative is seeking storage and hydro resources that require longer planning cycles than the four-year lead times in the pending Long Term 2 procurement.

hydro projects in the ISO procurements because they take longer than five years and they're not greenfield," Norris said.

John Wynsma, formerly of Peterborough Utilities, said that between 2008 and 2016, the company built one new hydro project while completing one expansion and one redevelopment, each of which took more than five years.

"The new-build was the cheapest of the three, and that's because of logistics: It's a clean site," he said. "The redevelopment cost 40% more than the new-build. The expansion cost more than 50% more than the new-build."

He suggested IESO allow redevelopments and expansions to submit prices for 20-, 30- and 40-year contracts in the LLT solicitation, with the ISO choosing any it finds attractive. "I think you're missing an opportunity here," he said.

IESO's Ben Weir said ISO officials are still deciding how they will treat hydro redevelopments under LT2. "It's a bigger piece of work that's just not going to be done by the time that LLT has to launch," he said.

"We do want to get a terawatt-hour worth of energy out of new-build hydro facilities in the province," he continued. "I understand that the timelines for LT2 have not been made public yet, but we do expect to make those public at the end of an engagement in February.

"Whether or not those expansions are going to take five years is a site-specific question," Weir added. "When we're talking about upgrades and expansions to existing facility, it's our position that a 40-year contract … shouldn't be required in order to recover the investment that's being made."

On Jan. 29, IESO held an engagement on its *Northern Hydro Program* (NHP), which will allow existing hydro facilities of at least 10 MW to win new 20-year contracts. NHP will begin accepting applications on March 31.

Concern over Reserve Prices

Boyer also raised concerns over IESO's plan to use reserve prices — a confidential price threshold — to ensure it doesn't pay too much in the LLT solicitation. The ISO said the thresholds will be based in part on prices in the first window of the LT2 procurement and differences in the obligations of LT2 and LLT resources.

Boyer said LT2 "is for different technology with different attributes, which is very different from the baseload hydro that you're looking at now to procure."

The reserve price and limited guidance over interconnection timelines is requiring bidders to make "a lot of investment … with a lot of unknowns and uncertainties," Boyer said.

Weir said the ISO will adjust the reserve price to acknowledge the differences between the LLT and LT2 procurements. "In no way, shape or form is it just the LT2 price," he said.

'Buy Local' Provisions not Final

ISO officials said they hope to complete the LLT RFP and contract by the end of the first quarter — with the bidding commencing in the fourth quarter — but are still waiting for the Ministry of Energy and Mines' directive on how to apply "buy local" requirements.

Bidders will be required to provide a "local supply plan" identifying their major goods, services and workforce suppliers, an attestation that the proponent plans to source at least 50% from Ontario or other Canadian provinces, and an explanation for what cannot be obtained domestically.

"The feedback that we're seeking is whether proponents were already planning to source at least 50% of the project spend from Ontario or Canada," Weir said. "If they weren't planning on doing that — but could, because there are domestic sources of those good services and workforce — what the cost implications would be to bring that level up to 50%."

Team Experience

The ISO also rejected requests that it allow proponents' consultants to help them meet the RFP's experience requirements.

All bidders will be required to have at least two team members with experience in planning, developing, financing, constructing and operating at least one "qualifying project" — an electric generation or storage facility that has reached commercial operation in the last 15 years in Canada or the U.S.

Proponents of Class II long-duration energy storage (LDES) technologies will be required to have at least two team members with experience on a project of the same technology (at least 1 MW) expected to reach commercial operation by the end of 2029.

IESO said consultants cannot count toward experience requirements because "they may not be enduring members of the project team" and could leave before the project reaches commercial operation.

Tariff Protections

Stakeholders also contended that the ISO should not have absolute discretion to cancel a contract if a developer seeks additional payments to compensate for tariff changes imposed after the deal is signed.

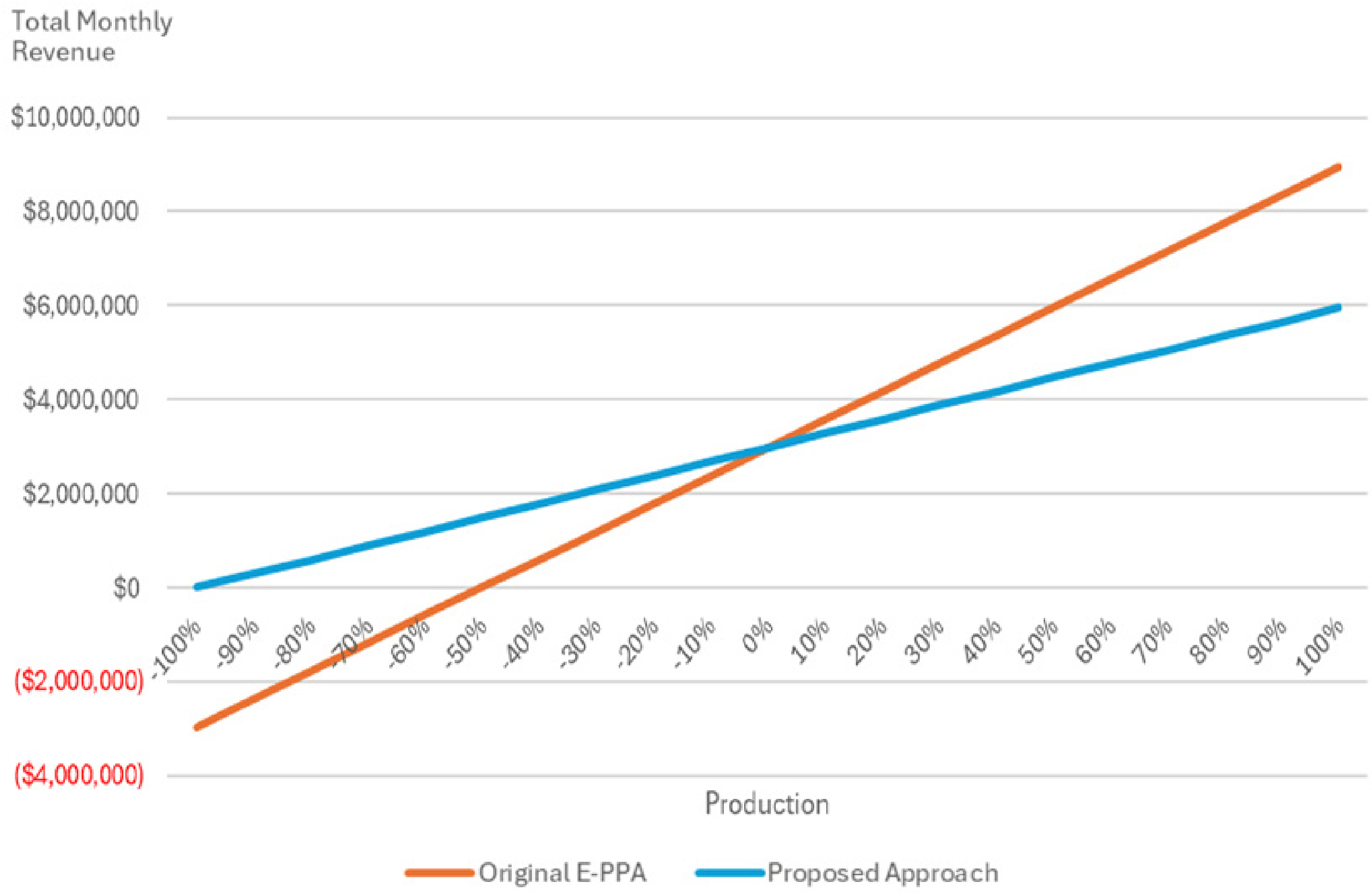
The ISO *said* developers should only submit tariff adjustment notices if the price change is "absolutely critical to maintain [the] viability" of the project "and should not be used … as a negotiating mechanism."

Other Issues

In other developments, IESO said it is:

- updating resource eligibility rules for storage to require that the instantaneous maximum withdrawal capability of the facility be equal to or greater than the project's nameplate capacity. For example, a 200-MW nameplate project must be able to withdraw 200 MW during its charging cycle.
- removing a requirement for obtaining municipal support confirmations by Aug. 21.
- seeking feedback on how to define hydro project sites to reflect impacts on adjacent properties, such as lands that may be flooded.
- adjusting its compensation formula to protect hydro suppliers' revenues during droughts that reduce production. IESO's Jasdeep Kahlon called it a "tradeoff" that will also reduce hydro projects' revenue "upside."

Stakeholder feedback on the Jan. 28 session is due Feb. 12. ■



If reduced water results in prolonged periods where hydro projects' production is lower than expected and energy market prices are high, it could result in negative total revenues when considering contract payments and market settlement. As a result, IESO is proposing an approach that reduces hydro suppliers' downside during droughts while reducing their upside when their facilities can produce more than contracted. | *IESO*

IESO, Stakeholders Ponder Changes to Hourly DR

By Rich Heidorn Jr.

IESO is reconsidering how it deploys hourly demand response (HDR) following complaints over partial activations and an increase in standby notices.

In a *meeting* Jan. 29, stakeholders expressed frustration over IESO's issuance of standby notices and said partial DR activations were harming performance. The ISO also heard concern about its announcement that the capacity targets set in the Annual Planning Outlook will no longer be binding and may be adjusted upward or downward before the yearly auction.

HDR 'Critical' During Emergencies

Hourly demand response accounted for more than half the capacity procured in the 2025 auction (53.4% of summer, 76.7% of winter). (See *Big Jump in Ontario Capacity Prices Signals Tightening Supplies*.)

IESO *said* HDR resources are "critical" to reliability during tight supply conditions but that they have historically underperformed, making it difficult for control room operators to maintain supply-demand balance during emergencies. In summer 2025, IESO activated 16,775 MW of HDR, but only 12,153 MW (72%) was delivered.

IESO previously triggered HDR activations manually during a Conservative Operating State or NERC Energy Emergency Alert 1. More recently, activations have been triggered by pre-dispatch scheduling run prices exceeding $2,000/MWh.

HDRs were activated 10 times in summer 2025 and seven times so far this winter, an increase from the historical rate of two to three activations in summer and none in winter.

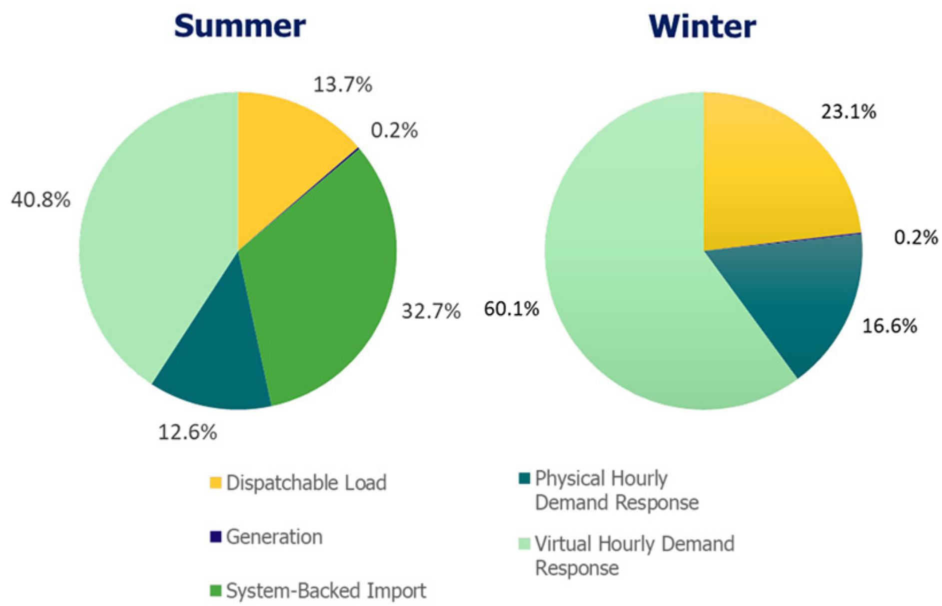
The ISO acknowledged that more frequent HDR activations could lead to "resource fatigue" and participants dropping out. In addition, "all-or-nothing" HDRs lack the ability to follow dispatch instructions for partial activations.

As a result, IESO said it will hold an engagement over the next three capacity auctions on potential changes to HDR rules and improvements to non-HDR rules that have been identified in previous engagements.

The engagement, scheduled to begin in Q1 2026, will initially focus on "achievable 'quick wins'" due to the limited time available before the 2026 auction, the ISO said.

Standby Notices

IESO issues standby notices to provide HDR resources time to prepare for potential activations.



Hourly demand response (HDR) accounted for more than half the capacity procured in the 2025 auction. Virtual HDR refers to aggregated DR resources that are not metered by IESO. Physical HDR resources are single, large transmission-connected or embedded load facilities that are revenue metered by IESO. | *IESO*

Why This Matters

Hourly demand response is critical to maintaining reliability during emergencies, but some IESO stakeholders are pointing to the 'unintended consequences' of using DR to also keep a lid on prices during intervals of tight supply.

Gilon Hershkowitz, of steelmaker ArcelorMittal, asked for guidance to help DR providers understand when standby notices will translate to activations.

"We want to be able to respond to the activations with our full capacity. [With] the short notice it's very challenging for us to do so," he said. "If we receive [fewer] standby notices and [have] a higher level of confidence that when we do receive a standby notice — maybe there's some other data that [will indicate] this notice will actually translate to an activation — teams can be prepared."

Laura Zubyck, IESO's capacity auction supervisor, said the ISO will review its procedures to "make sure the standby is working in the way that that we want it to."

Ted Leonard, of *EnPowered*, said the Market Renewal Program, which introduced LMPs and a financially binding day-ahead market in May 2025, has resulted in a "new normal" with unintended consequences.

"HDR [is] a reliability product; it wasn't constructed to have partial activations," said Leonard, IESO's former chief financial officer. "It's not meant to be there to help suppress prices during high demand events. It's meant to keep the lights on.

"Maybe we need to look back and say, 'Was this the intended consequence?'" he added. "Was this what HDR is all about, or HDR is meant to be? Because it feels like we're losing our way a little bit."

Zubyck said higher-than-normal temperatures during summer 2025 caused an increase in HDR activations and — for the first time — partial deployments.

"Now that we are seeing a partial activation of an HDR, we need to look at it, and we need to understand if there's perhaps some changes we need to make," she said.

Inefficient Decisions?

Roman Grod, of Rodan Energy, said his company has been challenged by partial activations that differ hour to hour. "Let's call it 10 MW in the first hour, 15 in the second and 20 in the third. … That's when I think it gets a little more challenging, because then you're forced to do this kind of cascading effect where you're activating folks for … three hours, then a different … side of your portfolio for two hours, and then another one for three hours," he said.

Aaron Lampe, of Workbench Energy, said the ISO's optimization engine is making inefficient decisions in picking HDR resources because "unlike for other resources, where the tools the ISO has built respect the operating characteristics of those resources — things like minimum loading point, ramp rates, minimum run-time, daily energy limits, etc. — none of those are reflected for the DR resource.

"And so, the optimization engine is picking the DR resource in situations to fill these short gaps, assuming this is an essentially infinitely flexible resource and then activating them. But it's actually a very expensive resource [because of] market payments outside of that optimization that are occurring."

Zubyck said the ISO is reviewing its rules "from a holistic level."

"It's not as simple as … we need to just fix partial activations, or we need to do this item. We do have to kind of look at everything that happened and consider … those bigger questions.

"This is the feedback we want to hear: that it's a challenge to go up and down for some resources, and that we may need to consider … solutions to deal with that," she added.

Other Priorities

Lampe said that stakeholders have been waiting for several years for action on items that were "shelved," in part because the ISO was consumed by developing the Market Renewal Program.

In late 2023, Lampe said stakeholders had a meeting with the ISO to discuss issues regarding DR data submission and metering requirements. "It's been two-and-a-half years or so [and] we haven't heard anything following up," he said. "I just want to ask: Are those still being tracked? … And how do those fit in the relative prioritization?"

Zubyck said the issues will be included in the new engagement. "We will bring those items back out and start to speak with stakeholders again about reprioritizing them and … allotting them into the next few auctions," she said. "They have not been shelved."

Changing Capacity Targets

Rodan Energy's Grod also expressed concern about the ISO's announcement that the capacity auction targets published in the Annual Planning Outlook (APO) each spring will now be preliminary, with the binding target published in the Pre-Auction Report in summer.

"This change provides additional flexibility for the IESO to adjust the target in response to issues/uncertainties that may emerge after the APO is published," said the ISO, adding that the changes "will have limited impacts on stakeholders."

"The ability to decrease the target concerns us significantly," Grod said. "Customers often commit to this program based off historic clearing prices and where they … see the market going. [The] target in the APO really provides some level of confidence that … pricing is going to stay somewhat stable.

"If the ISO has the ability to lower the target — say, by 500 MW — that's going to have a significant negative impact on pricing," he added. "And I frankly think that that's the wrong signal we want to be sending, especially as we're seeing this resource be … activated more and more often."

Bryan Timm, senior adviser on IESO's capacity auction team, said the ISO would raise or lower the target only in response to an "unusual or significant event."

"If [a] procurement delivered fewer megawatts than we anticipated, that might cause us to consider raising the target to meet system needs," he said. "So, these would be significant events, not … one-off, minor changes."

Feedback

Feedback on the Jan. 29 engagement is due Feb. 12 via the feedback form on the *Capacity Auction Enhancements* webpage. ■

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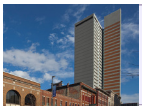
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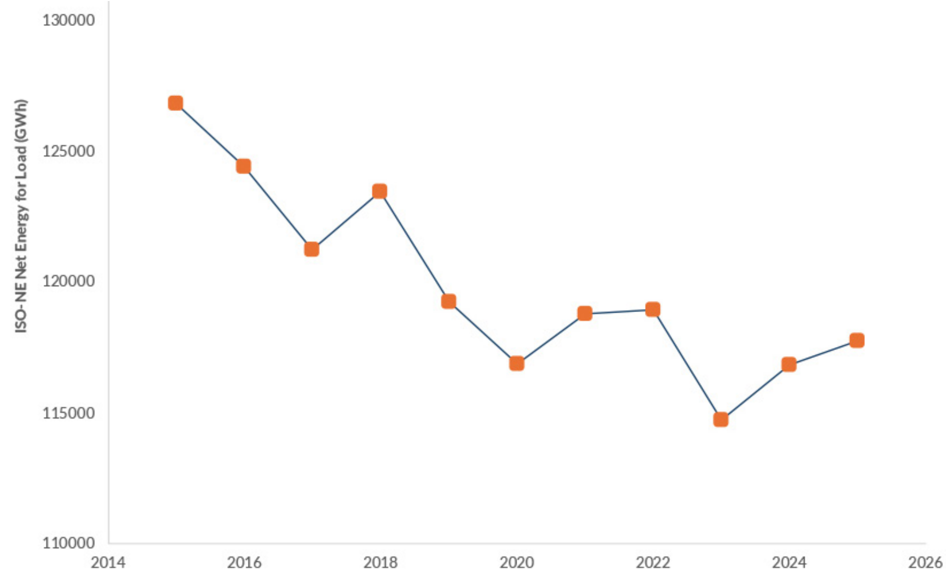
New England Power Demand Grew for 2nd Straight Year in 2025

By Jon Lamson

After years of declining or stagnant power demand in New England, annual energy demand ticked up for the second straight year in 2025, potentially indicating the start of a broader upward trend.

Total system demand grew by about 0.8% in 2025, while in-region power production increased by about 2.8%, according to *RTO Insider*'s review of *data* recently released by ISO-NE. Over the past two years, total energy demand has increased by about 2.6%, and in June 2025, the region experienced its highest peak load since 2013.

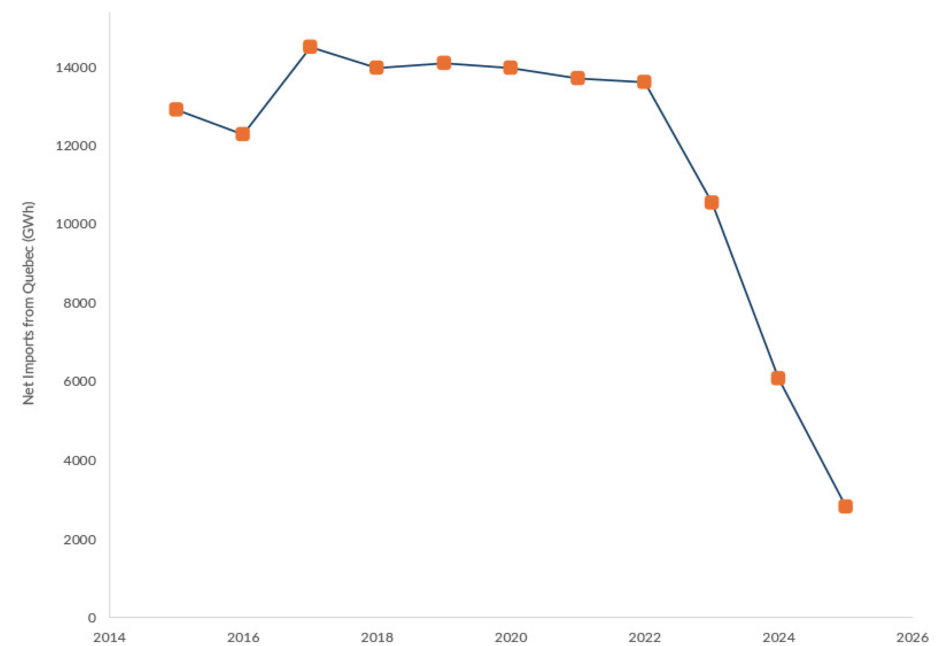


ISO-NE annual net energy for load | © *RTO Insider*

From the early 2000s through 2023, net energy for load in New England steadily declined because of energy efficiency investments and the growth of behind-the-meter solar. But ISO-NE expects electrification of heating and transportation to reverse this trend and predicts that annual energy demand will increase by 11.4% from 2025 to 2034, accompanied by a more than 2-GW increase in peak load. By 2050, ISO-NE forecasts peak load reaching up to 57 GW. (See *ISO-NE's Final 10-year Demand Forecast Tapers Expectations* and *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

These forecasts generally do not account for potential data center demand growth, which could add an additional significant source of demand growth. While high power prices have largely kept developers of large-scale data centers away from the region, its largest electric utilities have indicated an uptick in interest in large load interconnections from developers.

As demand increased in the past year, net imports from Québec declined by about 54%. 2025 marks the third straight year with a significant decline in imports from the province. Net imports accounted for just 2% of energy in the region in 2025, compared to an average of over 11% between 2014 and 2022.



New England annual imports from Quebec | © *RTO Insider LLC*

The decline in net imports appears to be driven in part by an ongoing multiyear drought affecting hydropower reservoirs in Québec. According to data from the energy consulting firm McCullough Research, the combined energy content at three of Hydro-Québec's largest reservoirs entered the winter at its lowest point in the last six years. (See *Drought, Climate Drive Uncertainty on New England Imports from Québec*.)

Hydro-Québec has said it reduced its exports in the leadup to the New England Clean Energy Connect (NECEC) and Champlain Hudson Power Express

Why This Matters

Accelerating load growth would likely require the region to make significant investments in new generation and transmission to meet demand. ISO-NE forecasts resource adequacy risks to increase in the 2030s.

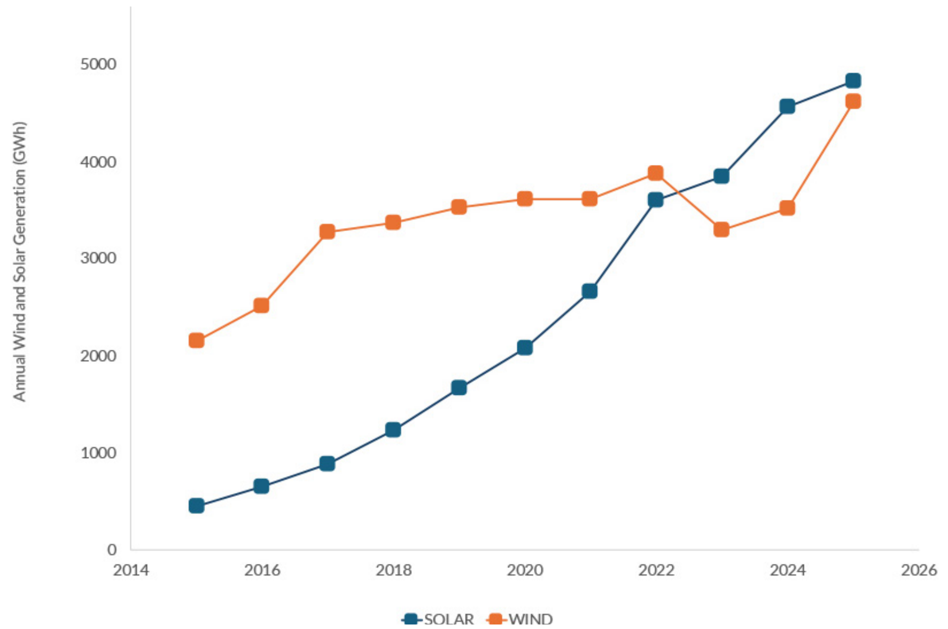
(CHPE) transmission projects coming online. Both lines include significant supply obligations for the company. NECEC began commercial operations Jan. 16, while CHPE expects to come online by midyear.

It is unclear how the NECEC line will impact New England's net imports from Québec. While Hydro-Québec has signed 20-year supply contracts with Massachusetts electric utilities for firm power at a fixed price, it is not prohibited from simultaneously importing power from New England on other lines.

While Hydro-Québec plans to make significant long-term investments to add renewable capacity and increase hydropower production, it has a slim reserve margin for the current winter, and reliability issues in the province have forced it to cut or reduce supply along the line for extended periods over the past five days. The contracted supply is not associated with new capacity supply obligations with ISO-NE, but the company faces penalties by Massachusetts for supply interruptions on the line. (See *Hydro-Québec Halted NECEC Deliveries amid Reliability Concerns*.)

Increased generation from gas, oil, wind, solar and nuclear resources helped fill the gap left by the decline in imports from Québec.

Nuclear and wind power saw the biggest year-over-year growth, both increasing by over 1,000 GWh. The region's nuclear fleet produced at its highest level since 2019, the year the Pilgrim Nuclear Power Station closed.



New England annual wind and solar generation | © RTO Insider LLC

Wind power in the region saw a boost as Vineyard Wind ramped up power production in the latter half of 2025. By the end of the year, the 800-MW project had reached about 72% of its production capability. Wind power should be in line for another big year in 2026 if Vineyard and Revolution Wind are both able to complete construction. Revolution is in the late stages of construction but has yet to start producing power. Both projects have obtained stays on the Trump administration's December stop-work order.

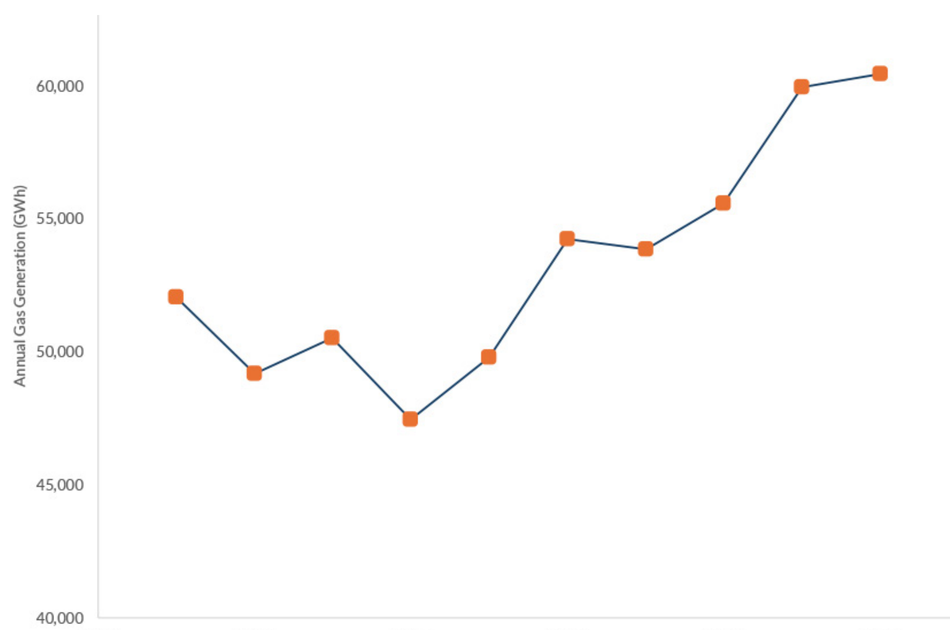
Wind and solar power each accounted for about 4% of total energy in 2025. Solar production increased modestly, by about 6%. This does not include behind-the-meter solar, which has grown significantly in recent years and is the largest category of solar in the region. ISO-NE's most recent load *forecast* projected behind-the-meter solar providing 6,316 GWh of energy in 2025, compared to the 4,836 GWh provided by front-of-meter solar during the year.

Oil-fired generation also spiked significantly in 2025. About 80% of this use occurred in January, February or December. The region's reliance on oil tends to be concentrated during high-demand winter periods when generators have limited access to pipeline gas. Over the past week, sustained cold weather has caused generators to rely heavily on their stored fuel inventories, with oil frequently meeting about a third of energy demand in the region.

Despite the region's heavy reliance on oil when temperatures drop, oil-fired generation accounted for less than 1% of total energy in 2025.

Gas generation in New England hit another record in 2025, increasing by about 0.8%. Annual gas generation in New England has increased by 21.4% since 2020.

The increased reliance on gas and oil generation contributed to an annual increase in power system carbon emissions. Based on data through Nov. 30, ISO-NE estimates that annual emissions rose by about 2%. ■



New England annual gas generation | © RTO Insider LLC

New England TOs Propose Asset Condition Projects Totaling $110M

By Jon Lamson

Eversource Energy and National Grid introduced asset condition projects totaling about $110 million at the ISO-NE Planning Advisory Committee meeting Jan. 27.

The proposals coincide with ISO-NE's ongoing efforts to establish an internal asset condition reviewer. This role is intended to increase transparency into the transmission owners' asset condition spending, which has cost the region billions of dollars in recent years. (See *ISO-NE Responds to Feedback on Asset Condition Reviewer Role*.)

Eversource *presented* a group of asset condition projects that would replace structures on six transmission lines in New Hampshire. The combined estimated costs total $101.6 million, while the expected in-service dates range from the fourth quarter of 2026 to the third quarter of 2027.

In southern New Hampshire, Eversource proposes a $32 million project on Line 367. The company would replace 97 345-kV wood structures with an average age of 55 years, along with a seven-year-old

Why This Matters

New England already has some of the highest transmission costs in the country, an issue that has been exacerbated by the growth in asset condition spending in recent years.

steel structure with damage from bullet holes. The estimated per-structure cost

Line 367 Structure 406
Pole top rot, splitting at attachment points, and checking along pole

Line B143 Structure 24
Pole top rot and splits, bending

Line M127 Structure 187
Major splitting, rusting hardware

Deteriorating structures on Eversource's 367, B143 and M127 lines | *ISO-NE* is $330,000.

Eversource's Steve Allen noted that the company estimates the typical useful life of 115- and 345-kV natural wood structures to be 40 to 60 years.

Fifty-seven of the structures on the line require immediate replacement, while Eversource also proposes to replace the 41 other original wood structures. Replacing all original wood structures would prevent the need for an additional project "in the near future," Allen said.

On Line A126, a 115-kV line in western New Hampshire, Eversource proposes a $7.4 million project to replace 20 wood structures with an average age of 72 years. The estimated per-structure cost is $370,000.

In southeastern New Hampshire, the company proposes to spend $38.1 million to replace 96 structures on the 115-kV A152 line. Twenty-eight of the structures need immediate replacement, while 41 structures have engineering concerns, Allen said. The average age of the wood structures is 57 years, and the estimated per-structure cost is $397,000.

Eversource proposes a $5.6 million project on the 115-kV B143 line in southern New Hampshire. The project would replace 16 wood structures at an estimated per-structure cost of $351,000. The structure ages range from 48 to 59 years.

In eastern New Hampshire, Eversource proposes a $5.5 million project on the 115-kV K174 line to replace 15 wood structures with an average age of 58 years. The company considers four of the structures to be immediate replacement needs. The estimated per-structure replacement cost is $370,000.

In central New Hampshire, the company proposes a $12.5 million project on the 115-kV M127 line. The project would replace 39 wood structures, which have an average age of 58 years, at an estimated per-structure cost of $321,000.

Allen noted that the ISO-NE *2050 Transmission Study* forecasts overloads on the A152 and K174 lines, though Eversource did not identify any project modifications to address these needs. ISO-NE plans to begin stakeholder discussions about right-sizing asset condition projects in the third quarter of this year.

Eversource also *presented* an update on asset condition projects at two river crossings affecting several lines in Connecticut. The modifications to the design have reduced the total estimated cost by about $5.5 million. The updated combined cost estimate now totals $101.3 million.

Rafael Panos of National Grid *presented* a $7.3 million asset condition project to replace a pair of 61-year-old circuit breakers at a substation in Brockton, Mass. The existing breakers are deteriorating and difficult to find parts for, Panos said. The project's estimated in-service date is May 2027.

Asset Condition Interim Review

Also at the PAC meeting, Brent Oberlin, executive director of transmission planning at ISO-NE, *discussed* the RTO's interim asset condition review process. ISO-NE is working to stand up the permanent reviewer at the beginning of 2027 and is relying on an external consultant to review nine selected projects during the interim period.

The list of nine projects in the interim review is mostly unchanged from the *initial list* ISO-NE presented in October, though the RTO has replaced National Grid's proposed rebuild of Line 323 in eastern Massachusetts with a different project by the company in western Massachusetts expected to cost more than $200 million. ISO-NE made the change after an outage opportunity arose for National Grid to pursue the 323 project on an earlier timeline, Oberlin said. (See *ISO-NE Gives Update on Asset Condition Reviewer Role*.)

ISO-NE has initiated the interim review for several projects and expects about a three-month review process for most projects on the list, he said, adding that the RTO plans to eventually present results to the PAC and "will be looking to take lessons learned and feedback on the interim process to inform the development of the permanent [asset condition] reviewer role."

Oberlin said additional asset condition projects that are proposed in 2026 but not on the interim list will not be subject to review. Jeff Iafrati, a consultant for Customized Energy Solutions, expressed concern that this could result in TOs advancing projects for the rest of the year to avoid review.

Alex Lawton of Advanced Energy United echoed this concern, saying, "It would be more assuring if there was a bit more review for upcoming projects."

"While it's a possibility, I really think it's a limited risk," Oberlin responded. ■

With Sunrise Wind Ruling, OSW Industry now 5-0 Against Trump Admin.

Last Remaining Federal Stop-work Order Against Offshore Wind Set Aside

By John Cropley

A judge has granted developers of Sunrise Wind a *preliminary injunction* against one of the federal stop-work orders slapped on U.S. offshore wind construction.

The Feb. 2 ruling in the U.S. District Court for the District of Columbia (1:26-cv-00028) completes the judicial pushback against the Trump administration: One by one, in the space of three weeks, four judges have granted the five projects under construction in U.S. waters permission to resume construction.

Sunrise Developer Ørsted said it would resume construction of the 924-MW project as soon as possible and said: "Sunrise Wind will determine how it may be possible to work with the U.S. administration to achieve an expeditious and durable resolution."

Durable is an important caveat.

President Donald Trump has attacked offshore wind relentlessly, starting with an executive order hours after his second term started. His administration has moved on multiple fronts to hinder construction of projects underway and block future construction from starting.

This culminated in the five stop-work orders issued Dec. 22 on grounds of national security that now have been set aside.

Revolution Wind got its injunction Jan. 12, Empire Wind Jan. 15, Coastal Virginia Offshore Wind Jan. 16 and Vineyard Wind Jan. 27.

Counting an August 2025 stop-work order against Revolution that a judge lifted and an April 2025 stop-work order against Empire the Trump administration removed after discussions, the administration's record is 0-1-6.

Why This Matters

The federal courts have for now blocked the Trump administration's efforts to halt offshore wind construction.

Components for the Sunrise Wind offshore wind project are staged in Coeymans, N.Y. | *NYSERDA*

But the fight is not over, and the administration has secured an important achievement: Investors likely have been scared away from U.S. waters. Further, the offshore wind industry has been thwarted in its attempts to develop infrastructure, create an industrial ecosystem and build project momentum in the U.S.

There also is considerable financial impact on the developers.

Empire placed the cost of the April 2025 stop-work order at $200 million. Court papers estimated the costs at "millions per week" for Revolution and $2 million a day for Vineyard.

In a *Jan. 30 regulatory filing*, Dominion tallied the full cost of the December shutdown at $228 million.

Sunrise, which is at an earlier stage of construction than the other four projects, said in its Jan. 6 complaint that the shutdown was costing it more than $1 million a day.

Oceantic Network *cheered this latest victory*. CEO Liz Burdock said:

"Sunrise Wind represents a vital investment in strengthening both Long Island's power system and the broader regional grid that millions of residents rely on — particularly during the harsh winter months. Offshore wind is uniquely suited for these conditions and stands ready to deliver steady, abundant power, easing the burden on families who have long relied on costly peaker plants to keep the lights on. Oceantic applauds this decision, which moves us closer to providing reliable, affordable clean energy and creating high-quality jobs for the communities that stand to benefit the most."

New York's senior U.S. senator, Charles Schumer (D), *posted on X*: "Trump just received his 5th straight loss in the courts in his crusade to stop offshore wind and kill thousands of jobs. Trump is losing his war against offshore wind. I will keep fighting to make sure these projects and the thousands of good-paying jobs they create move forward to help reduce energy costs for the country."

Some of the many opponents of offshore wind wasted no time replying.

"SHAME ON YOU! SHAME! SHAME! SHAME!" was among the milder comments. ■

Facing Rising Demand, New England has Limited Options for New Supply

NECA Conference Explores Energy Challenges Facing Region

By Jon Lamson

Why This Matters

Long-term supply issues could exacerbate existing affordability issues in the region. How to address these problems could becoming an increasingly important debate over the next few years.

BOSTON — While there is near-universal recognition that New England will need to add a significant amount of new generation over the next two decades, conflicting political and market forces have created major uncertainty about what the next wave of generation projects will look like.

This uncertainty extends to how the region will spur the development needed to meet demand growth, several speakers said at a Northeast Energy and Commerce Association conference on power markets in Boston on Jan. 29.

The scale of the need could be substantial: ISO-NE forecasts peak load roughly doubling by 2050, and decarbonization would require additional clean energy to replace much of the existing fossil fuel fleet.

Incentivizing new generation solely through the wholesale markets may be a difficult proposition. Although energy affordability has dominated policy discussions over the past year, wholesale market prices had remained relatively low until the past two months, which have brought a major increase in energy costs due to sustained cold weather. (See *Cold Weather Drives Record December Energy Costs in New England*.)

Dan Dolan, president of the New England Power Generators Association, said there has been a "dramatic disconnect" between consumer costs and wholesale market prices. For generators relying on capacity and energy revenues, "if anything, there's a revenue crisis."

With consumer prices already high, the increased energy and capacity prices needed to spur new development could lead to political backlash and caps on market prices.

This dynamic has occurred in PJM, where "we're just now seeing these markets shifting from being long on capacity to being more at equilibrium," said Ben Griffiths of NRG Energy. "It's not clear that the prices that [power developers] would require to bring in new entry are actually politically feasible."

If market prices alone are not enough to bring new generation online, the New England states could assume an even larger role in the procurement of new generation and capacity. But continued reliance on state power procurements would bring its own set of difficulties.

Connecticut's 10-year power purchase agreement with the Millstone nuclear plant has demonstrated some of these challenges. The difficulty of reconciling PPA costs through rates has led to major swings in the monthly costs to consumers, and Connecticut officials have been pushing for other states to shoulder some of the plant's costs after the current contract expires in 2029.

Griffiths noted that former ISO-NE CEO Gordon van Welie had pushed the states to take on a larger role in capacity procurement through bilateral contracting.

He added that the region could consider capacity market changes aimed at increasing revenue certainty, such as altering the demand curve to stabilize prices or reintroducing some version of a price lock for new capacity.

But he expressed skepticism about the long-term sustainability of the proposal by the PJM state governors and the White House's National Energy Dominance Council for a one-time "backstop" auction to procure 15-year contracts with new capacity resources. (See *Government-proposed 'Backstop' Auction to Test PJM Stakeholder Process*.)

"It doesn't feel long-term sustainable to have bifurcated markets that are providing the same benefits in real time," Griffiths said, adding that he is "increasingly skeptical of the approach of trying to move all the money out of the capacity market."

Bob Ethier, current PJM board member and former vice president of system planning at ISO-NE, stressed the need for longer-term solutions to high costs.

"The tension that I see is that there are times where we can do things in the short term that will lower bills but will hurt the market's functioning in the long run," he said, emphasizing the importance of maintaining long-term entry and exit signals in the market.

Multiyear price locks for capacity could help reduce year-to-year price volatility, he said, adding that states may be better situated to pursue this strategy than RTOs. He emphasized the need to have these conversations prior to price spikes.

Once a crisis hits, like in PJM, "all we can do is ride [it] out, tweak things around the edges and hopefully learn from it for the next one."

Policy Pickles

Conflicting objectives between federal and state policies have also added significant challenges and uncertainty to resource development, several speakers said.

"We're in a pickle in the region for what we can build and what is a sound investment," said Matt Nelson, principal at Apex Analytics and former chair of the Massachusetts Department of Public Utilities. "We've lost some tailwinds and are picking up a lot of headwinds when it comes to clean energy policy."

Despite the load growth projections and increased demand over the past two years, there is a relatively small amount of generation in the ISO-NE interconnection queue. The first iteration of the Order

2023 cluster study process, initiated by ISO-NE in October, includes 5,632 MW of storage, 355 MW of solar and the 1,200-MW SouthCoast Wind project, which faces considerable challenges from the Trump administration. (See *Storage Projects Dominate ISO-NE Transitional Cluster Study*.)

Nelson said each new resource category has its own drawbacks: New gas generation seems unlikely with the region's winter gas constraints and grid's current "overreliance" on gas; new nuclear looks to be at least 10 years out; the federal government appears to have taken offshore wind off the table; and large-scale solar development faces questions about the loss of federal incentives and a potential capacity revenue hit from ISO-NE's proposed accreditation changes.

To address load growth amid so much uncertainty about sources of new development, the region must build consensus around a cohesive plan, Nelson said. He added that distributed solar and storage may play an increasingly large role over the next few years.

"State programs are about the only thing left where clean energy resources can get an incentive," he said.

Aaron Lang, a lawyer focused on clean energy development at firm Foley Hoag, said renewable developers are dealing with "a mountain of uncertainty" related to tariff policy and other potential state and federal policy changes over the past year.

"The pressure is really on the states to do a lot of stuff," he added, while expressing some optimism about Massachusetts' efforts to establish a new consolidated permitting and siting process for clean energy resources.

The new process stems from climate and energy legislation passed by the state in 2024. Under the new rules, developers must apply for consolidated state and municipal permits, with the permitting review process limited to 15 months for large projects and 12 months for smaller projects.

The law requires the state to promulgate final regulations by March 1. The state plans to start processing projects through the new process in July.

While there may be some short-term "bumps in the road," the new process should provide long-term benefits for resource development, he said. "The idea of a consolidated permit is an excellent idea."

Consumer Cost Drivers

Over the past couple years, New England has seen electricity prices rise faster than inflation, though the inflation-adjusted rate of increase has been relatively modest for most of the region, said Todd Schatzki, principal at the Analysis Group. When accounting for use and rates, customer costs have fallen since 2010 but have risen since 2020, he said.

He emphasized that the cost increases are not felt equally by all customers, with larger impacts on residential customers who have not seen wage growth in line with inflation.

From left: Dan Dolan, NEPGA; Sandy Grace, National Grid; Todd Schatzki, Analysis Group; Ron Gerwatowski, Rhode Island Public Utilities Commission; Nicholas Hutchings, NextEra Energy Resources | © *RTO Insider*

Sandy Grace, vice president of U.S. policy and regulatory strategy at National Grid, presented a cost breakdown of a typical Massachusetts residential electric bill for November. The main cost categories were energy supply (41.3%), distribution (21.4%), transmission (14.9%), energy efficiency (7.6%), net metering (4.6%) and utility fixed charges (4.4%).

"It really does require a partnership across sectors to address these costs," she said.

Rhode Island Public Utilities Commission Chair Ron Gerwatowski focused much of his remarks on the rise of transmission rates in the region.

Asset condition spending, or investment to address degradation of existing transmission infrastructure, has risen significantly in recent years and makes up the bulk of new regionalized transmission spending in ISO-NE. The rising costs, coupled with the limited regulatory scrutiny the spending receives, has prompted efforts to establish internal asset condition review capabilities at ISO-NE.

While this role would not be a regulatory entity, it would be intended to increase transparency into projects and provide information that could be used by third parties to challenge project costs with FERC.

"Quite frankly, it may not be enough," Gerwatowski said. "We need the transmission owners to temper their appetite for investment in asset condition projects."

If transmission owners do not scale back their spending, the states may be forced to try to step in and do it for them, he said, noting that states "still control both the method and the timing" of how transmission rates are recovered.

Instead of allowing the quick recovery of transmission spending as pass-through costs, the states could require the recovery of transmission costs through the full base rate case process, he said.

Introducing regulatory lag "could give the financial folks an incentive to push back" on asset condition spending, he said.

If state regulators have little or no confidence in the asset condition planning and development process, he added, "What other options do we have?" ■

MISO Hits Pause on Integrated Survey Idea After Regulator Unease

By Amanda Durish Cook

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MISO has deferred plans for an all-encompassing future-looking assessment that relies on member data after state regulators appeared hesitant about the move.

MISO has its sights set on creating what it calls an "integrated forward assessment," which would rely on member data to create a one-stop data source for transmission planning, resource adequacy insights, load growth and operational needs.

But some members of the Organization of MISO States (OMS) voiced reservations over how much involvement state regulators would be permitted, or how much influence they would wield over resource adequacy conclusions.

MISO *canceled* a March 4 workshop to discuss the possibility of a comprehensive assessment. It said it postponed the meeting to a later, unspecified date.

"In the context of growing load, an evolving fleet and a new resource accreditation framework, MISO sees a need to update some of the data and processes underlying the forward assessments we provide," MISO spokesperson McKenzie Barbknecht said in a statement to *RTO Insider*.

MISO's forward assessments include its 20-year transmission futures, its 20-year regional resource assessment, its five-year-out resource adequacy survey in conjunction with OMS and its new attempt at long-term load forecasting.

The Bottom Line

MISO planned an early spring workshop to introduce its idea for a universal forward assessment that could feed into transmission and resource planning. After hearing state regulators' skepticism, it put those plans on ice.

However, MISO added it's still determining the "exact scope" of what an integrated forward assessment would encompass.

MISO said the "effort must build on MISO's partnership with OMS."

During a Jan. 22 OMS Board of Directors meeting, Minnesota Public Utilities Commissioner Joseph Sullivan said he worried that MISO's assessments might supplant the annual OMS-MISO resource adequacy survey. He said OMS might need to draw up a written agreement with MISO on how data is construed.

Multiple regulators said they worried about the messaging MISO could share as a result of the surveys and whether OMS's stamp of approval might be automatically placed on MISO's conclusions.

Werner Roth, economist with the Public Utility Commission of Texas, said he wasn't willing to accept "anything less than a full partnership" between OMS and MISO on a more universal assessment.

MISO Senior Vice President Todd Ramey said MISO understands that regulators are in control of resource adequacy in the footprint.

"You guys are in the driver's seat here," Ramey told OMS members.

In comments to MISO, OMS said it "cautiously supports moving forward" with an integrated survey design. It said it recognizes that MISO stakeholders could benefit from the increased efficiency and "minimized" confusion that could accompany a more streamlined point of data collection.

Regulators, though, said MISO must take care to preserve state jurisdiction and keep "clear lines of communication" with OMS regarding which data inputs to collect, what scenarios MISO paints and how MISO interprets results.

"Continued discussion and buy-in from the OMS Board will be required as the process develops and on an ongoing basis in order to ensure effective and useful assessments; agreement on that process is a key component needed before entering this discussion," OMS wrote.

The organization added that it would be open to establishing a memorandum of understanding or enshrining some ground rules in the MISO tariff of business practice manuals.

Barbknecht said MISO "greatly appreciates" OMS's input and "is taking the time needed to review before moving forward." ■

Stakeholders Say MISO's Nonpublic Extreme Events Study Merits Closer Look

By Amanda Durish Cook

Some MISO stakeholders said an extreme events analysis from the 2025 transmission planning cycle potentially raises a red flag and deserves more attention.

MISO *found* the possibility for cascading outages in all four of its planning regions in its annual extreme events analysis for its 2025 Transmission Expansion Plan (MTEP 25). The grid operator said its South region contains the most potential for cascading, extreme contingencies.

MISO completed the analysis in late 2025. The analysis contemplates several failures, including loss of large generators, transmission elements, load centers and failures brought on by hurricanes, wildfires, cyberattacks and other catastrophes.

However, there's not much to glean beyond that. Results are shielded from the public in the confidential appendices of the annual MTEP report and protected by nondisclosure agreement requirements and a Critical Energy/Electric Infrastructure Information designation.

Sustainable FERC Project's Natalie McIntire asked where stakeholders can go to view a list of transmission solution ideas or remedial action schemes that might be designed because of the findings.

Clean Grid Alliance's David Sapper seconded the ask. He said 2025's "concerning results" warrant more discussion, not simply an agenda item without a presentation from MISO staff.

MISO published the analysis results in a "post-only" format without dedicated discussion time at a Jan. 28 Planning Subcommittee meeting.

"'It is what it is' suggests too much indifference," Sapper said at the meeting.

Minnesota Power's Tom Butz asked if the extreme events analysis findings could be discussed in MISO's Resource Adequacy Subcommittee.

Grid damage in Calcasieu Parish following Hurricane Laura in 2020 | *Entergy Louisiana*

The Takeaway

Some stakeholders say the potential MISO found for cascading grid failures during extreme events warrants more discussion. But sharing insights from MISO's nonpublic analysis will be delicate.

Butz said the analysis seems to deserve a larger conversation on "system reliability, not just a localized version of reliability" for transmission owners.

"It seems like this is a source for this to come from," Butz said of a discussion on how to tackle some cascading failures. He said MISO should "connect the dots between the two worlds," meaning local planning versus regional preparation.

"We'd be more than willing to have more conversations," MISO engineer Scott Goodwin said.

But Goodwin reminded stakeholders that loss of load is at times an acceptable form of mitigation, according to MISO's planning standards.

Planning Subcommittee Chair Patrick Jehring, of GridLiance, said he understands the "difficulty" of trying to publish findings while working around privileged information.

"What we heard today is kind of lacking. … It doesn't really help drive a conversation about 'what do we do about this?' What can you show to form a discussion about these extreme events?" Jehring asked MISO staff.

Senior Expansion Planning Engineer Amanda Schiro said she would evaluate what insights MISO might be able to share.

McIntire said MISO might consider sharing aggregated data or "themes of analysis." ■

MISO Pushes Interconnection Queue Timelines Back Again

By Amanda Durish Cook

MISO announced further delays in its generator interconnection queue for the cycles of projects that entered in 2022, 2023 and 2025.

The grid operator said it does not expect to complete the second phase of studies for 2022 project entries until May 7, 2026. MISO similarly said 2023 project entries would not finish second phase studies until Sept. 3, 2026. The RTO conducts its interconnection studies in three phases.

The updated timeline is months behind what MISO originally said it could manage as it rolled out a new, automated study process.

In early 2025, MISO hoped to have all generation projects in the 2022, 2023 and 2025 cycles striking interconnection agreements over 2026, with 2025 project entries finishing up by year-end. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

Now, MISO does not expect the 2022 cycle of projects to execute generation agreements until early January 2027. The 2023 cycle would follow in late March 2027.

MISO reported that the 2022 class of generation hopefuls are experiencing modeling delays across all regions.

"We're still so bogged down by previous cycles and restudies and the backlog churn," Senior Manager of Resource Utilization Kyle Trotter explained at a meeting of the Interconnection Process Working Group on Jan. 27. "We have '21, '22, '23 and '25 all in flight at the same time."

The Bottom Line

MISO continues to be dogged by its logjammed generator interconnection queue and has tacked a few months onto the 2022, 2023 and 2025 cycles' expected completion dates.

MISO is nearing completion on its 2021 cycle, save for a cascading model delay for projects located in its Central region.

The later timeline leaves the 2025 cycle of projects pushed later as well, though MISO has yet to estimate realistic dates. The RTO's most recent queue processing *chart* targets the 2025 cycle's dates according to the scheduling prescribed by FERC Order 2023. If MISO were to follow that, it would have to complete the second study phase by mid-July and sign interconnection agreements in early February 2027, months ahead of the expected wrap up of the 2023 group.

But Trotter said MISO would not begin the second batch of studies on the 2025 cycle of projects until it has sufficiently moved the 2023 cycle along. He said it would seek a waiver with FERC to delay studies for the 2025 cycle.

"We haven't yet been in contact with FERC about it, in filing a waiver for the 2025 cycle," Trotter said.

Trotter declined to provide more details on what exactly the RTO would request to waive. He said it is still discussing details internally with its legal team and must engage FERC before presenting its request to stakeholders.

David Ticknor, senior interconnection engineer at RES Group, reminded MISO of the importance of working quickly to approve projects so that renewables can secure federal tax credits before their discontinuation.

MISO in late 2025 refused stakeholders' request to delay kicking off studies for the 2025 cycle to clear some of the four-year backlog before taking on more analyses. (See *MISO Declines Stakeholder Ask for Pause on 2025 Queue to Clear Backlog*.)

Stakeholders asked where it stands on acceptance of 2026 cycle of generation projects.

"We would project the 2026 cycle closing at the end of the year, similar to years past," Trotter answered, adding that study kickoff would occur in early 2027.

In a related queue matter, MISO wants to standardize its collection of data from generation developers to help reduce its power flow modeling delays.

AES Indiana's 200-MW Pike County BESS was completed in 2025. | *Fluence*

Manager of Resource Utilization Rob Lamoureux said the RTO needs rule changes to make sure it receives consistent modeling data from developers. He said it could complete studies faster and more accurately if it could draw on identical fields for modeling data.

Lamoureux said the various fields slow down MISO's modeling and that a more regimented data collection would produce better models for Pearl Street's *SUGAR* software, which the RTO is using to automate studies.

"Half of the files from '23 and '25 had to be manually reworked," Lamoureux told stakeholders. He said MISO had to intervene to manually feed data into its systems for 50% of the modeling files from the 2023 cycle and 53% of files in the 2025 cycle.

He reminded stakeholders that MISO would face penalties of $1,000 to $2,500 per business day by the 2027 cycle under Order 2023 if it does not reasonably meet deadlines.

Ryan Westphal said MISO's tariff currently permits more than a dozen formatting methods. In some cases, it receives conflicting data in redundant entries from the same developer, he said.

Lamoureux said MISO would put together a draft data standard for stakeholder review in time for the IPWG's March 10 meeting.

"If we get these changes out soon, they could be implemented before the 2026 cycle," he said. ■

Regulators: MISO Stakeholders Should Decide Cost-sharing for DOE Coal Plant Orders

State Commissions Ask FERC to Let Stakeholders Divvy up Costs to Maintain Indiana Plants

By Amanda Durish Cook

Flue gas desulphurization work on the R.M. Schahfer Generating Station in 2016. | *Walters Group*

State regulators in MISO asked FERC to let power industry stakeholders determine how to allocate the costs of an Indiana coal plant forced to stay online by the Trump administration's Department of Energy.

The Organization of MISO States (OMS) said the RTO's stakeholders and regulators should decide on now to divvy up the costs of sustaining operations at thermal plants whose retirements are delayed under emergency orders issued by DOE under Section 202(c) of the Federal Power Act.

Northern Indiana Public Service Co. — whose units 17 and 18 at its R.M. Schahfer Generating Station are under such orders through March 23 — filed in late 2025 to recover costs of running the plant from MISO Midwest participants (EL26-36). (See *Enviros Warn NIPSCO Against Rebuilding Coal Unit on DOE Emergency Order*.)

FERC previously approved a cost allocation plan for MISO Midwest entities to split the expenses of running the J.H. Campbell coal plant in Michigan — another of a handful of aging thermal plants set to retire that DOE says can't be spared due to reliability concerns.

OMS said instead of applying a similar allocation, FERC this time should task MISO with engaging its member states and stakeholders to design a cost allocation for the Schahfer units. If FERC decides against that avenue, it should open NIPSCO's request for an allocation plan to a hearing that weighs anticipated rate impacts and provides opportunity for comments from affected states and customers, OMS said.

The Bottom Line

State regulators in MISO said they and other stakeholders should have a say in allocating costs for keeping retiring coal plants open under the DOE's ever-growing emergency orders.

"In either case, OMS stresses that any ultimate cost assignment that results from this proceeding should be based on a clear demonstration of need and commensurate with benefits received to help mitigate unintended consequences," OMS wrote.

OMS said if FERC continues to allow the costs of emergency orders to be allocated across MISO Midwest, generation owners could start to exploit a predictable outcome.

"If the commission routinely approves broad regional cost allocation for 202(c) order costs without a demonstrated, commensurate benefit, utilities may be incentivized to accelerate retirements and cash in on a 202(c) order cost shift, moving costs away from local customers and onto an 11-state region," OMS wrote in Jan. 20 comments to FERC.

The regulators' group said DOE's "self-determined energy emergency does not obviate the commission's obligation to establish just and reasonable rates." It said a cost allocation design should be "equitable and durable," especially because DOE is likely to order other retiring thermal units to stay in service.

OMS noted also that while FERC regulates wholesale markets and interstate transmission, "states are responsible for determining what generation is needed, where it is located, how it is financed and whether it is prudent to serve retail customers."

OMS said NIPSCO's proposal would spread Schahfer expenses broadly across MISO Midwest, even to customers who won't experience any reliability benefit, "including Indiana." The group noted that PJM, its member states and stakeholders were allowed to develop a cost-recovery plan last year when DOE ordered Constellation Energy's Eddystone Generating Station to keep running.

Multiple OMS members abstained from the vote to submit the comments, including the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Mississippi Public Service Commission, the New Orleans City Council, the Public Utility Commission

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MISO Suggests Reliability Requirements, Partial Supply Deals to Handle Large Loads

By Amanda Durish Cook

Rendering of Meta's Rosemount Data Center in Minnesota, set to be completed in 2026 | *Meta*

MISO said it likely will create interconnection reliability requirements and explore new rules that could bring large customers online in stages, as capacity becomes available, to get a handle on large loads eyeing MISO locales.

MISO anticipates drafting "a set of guidelines and requirements" for large loads that wish to interconnect to maintain reliability. The RTO made the announcement at a Jan. 30 stakeholder workshop dedicated to large load preparation.

Executive Director of Markets and Grid Research DL Oates said MISO's stakeholders view the grid operator as having a role in providing reliability interconnection guidelines.

Manager of Strategic Assessments Beibei Li said MISO can draw on its existing inverter-based resource requirements for ideas. She said MISO would need loads' telemetry to maintain system reliability and stability and that it would use their data in modeling and planning.

MISO plans to introduce the topic to the Planning Advisory Committee for discussion in the next few months with the goal of working on a ruleset sometime around mid-2026.

Oates said MISO "is hesitant to provide exact dates" on when it could file tariff changes with FERC on the reliability requirements.

Oates said for years MISO has operated with an approximate 120-GW peak demand across its 45 million customers. He said by 2030, MISO could add anywhere from the "low 10s to the high 20s" of gigawatts.

"So, something like 15% of growth with a fair bit of uncertainty around that," he said.

Oates said the new load coming MISO's way is unlike anything MISO has seen: "It is, to put it very simply, very big."

Jordan Bakke, MISO's director of strategic insights and assessments, said there's sizable reliability risk that large load customers could introduce.

"We expect large loads to behave in a way that's hard to predict," Bakke said. He said large loads have "unique disturbance behaviors," including frequency sensitivity, low fault current and oscillations. He also said these loads have "unknown and varied ride-through performance" alongside complex protection schemes that make for complex stability assessments.

Minnesota Power's Tom Butz said MISO appeared to have a great number of concerns over stability that come with large load customers. He asked if MISO has existing study processes to test how large loads specifically strain the system.

"MISO itself has very limited study as it relates to large load interconnection," Bakke said.

Vice President of Operations Renuka Chatterjee said MISO will be "looking at some AI tools" for study assistance and promised "more to come."

'Speed to Partial Power'

MISO is toying with the idea of providing what it calls "speed to partial power."

MISO Director of Expansion Planning Jeanna Furnish said large loads can make it online in a little more than a year, while generation takes about four years and transmission typically takes about seven to 10 years. She said load could be left trying to withdraw before generation or transmission arrive on scene.

Furnish said MISO's ongoing work to create zero-injection generator interconnection agreements can help speed up generation projects that plan to send their output solely to their dedicated loads, not the greater system. (See *Questions Abound over MISO Idea for Zero-injection Agreements*.)

However, Furnish said MISO could implement ideas "while we wait on infrastructure."

Enter MISO's "partial power" brainchild. The grid operator said in some cases, it probably could serve a portion of large load customers' needs with existing transmission for an interim period. Load

The Bottom Line

MISO said it could roll out reliability guidelines and requirements, incremental interconnections and a reserve product makeover to manage new large loads on the system.

then could be scaled up incrementally as generation or transmission is constructed. Finally, once construction is complete, the full load could be served with firm withdrawal capability at its interconnection point.

Furnish said providing service to fractions of load "helps address the challenges of using the system that is available and manage service as conditions change." She said a ramp-up to firm service allows service even as upgrades come online.

Furnish said discussions on partial service applications similarly will be held at Planning Advisory Committee meetings.

Butz cautioned that MISO and members need to focus on energy adequacy because new large load customers have "twice the load factor" of MISO's average load. He said the load surge comes as MISO's highest-capacity-factor thermal resources plan to retire in droves.

"It's really crucial that we understand how to serve high-load-factor load," Butz said.

Chatterjee said MISO will strive to create "timely paths" for integrated large loads but "must keep the system reliable today and in the future."

Chatterjee said MISO would examine which initiatives it could move fast on "without boiling the ocean." She said MISO already has done the "foundational work" to open up grid capacity through its expedited transmission project work.

Furnish also said MISO wouldn't "copy and paste" other RTOs' proposals in the large load space but is evaluating their work.

Reserve Product Revamp

Additionally, MISO said it needs to recalibrate its reserve products to account for greater uncertainty introduced by large loads.

Director of Reliability Coordination John Harmon said the "behavior of large load" isn't reflected today in MISO's ancillary service setup. He said MISO probably will have to keep more reserves and revise reserve products' demand curves.

Harmon said large loads can quickly increase or decrease demand, especially when co-located generation or the load itself suddenly goes offline.

Harmon said the Reliability Subcommittee would handle modernizing the reserve scheme and noted the group already is working to create a dynamic regulation and ramp product that calls up a greater volume of reserves as system uncertainty rises.

Stakeholders asked what role MISO sees itself playing in controlling added costs on the system from load growth.

Bakke said that while MISO cannot influence much of the consumer costs that come with large loads, it views itself as responsible for cost-effective regional transmission planning to minimize the volume of more expensive, piecemeal transmission upgrades. He said MISO likely must overhaul some of its process for furnishing reserves, since it expects that reserves will be used more often.

MISO will hold three more workshops on large loads over 2026: on April 30, July 31 and Oct. 29. ■

Regulators: MISO Stakeholders Should Decide Cost-sharing for DOE Coal Plant Orders

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of Texas, and, interestingly, the Indiana Utility Regulatory Commission.

FERC has rejected similar requests in the case of the J.H. Campbell coal plant when it decided in late summer 2025 that costs should be spread across MISO Midwest. Those costs have risen to $80 million and climbing after three emergency orders. (See *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States* and *J.H. Campbell Tab Rises to $80M on DOE's Stay Open Orders*.)

Consulting Firm Predicts Tens of Millions in Costs

Keeping Schahfer units 17 and 18 operating is likely to come with steep costs. Synapse Energy Economics estimated that DOE's initial 90-day extension of the trio of Indiana coal plants under emergency orders — the Schahfer units and CenterPoint's Culley Unit 2 — would cost $20.6 million under economic commitment practices. Schahfer would account for the lion's share of the cost, which could rise significantly, the consulting firm found.

"If DOE extends the order long term, we estimate the coal units would require an additional $33.7 million per year in capital expenditures to replace equipment as it wears out and install environmental controls to maintain compliance with environmental regulations," Synapse wrote in a *report* prepared for Earthjustice, Sierra Club and the Environmental Law and Policy Center.

All three units were to retire at the end of 2025.

Synapse's numbers don't account for the extensive turbine repairs NIPSCO has said Schahfer Unit 18 requires immediately before becoming available for dispatch. NIPSCO officials have said that work could take six months or more.

The Illinois Commerce Commission likewise asked FERC to give states and stakeholders space to asses a suitable cost-recovery for the Culley unit under CenterPoint's complaint for a cost allocation mechanism (*EL26-38*). The ICC said DOE's orders are becoming "routine" and order issuances could go on for years.

"The likely frequency and length of these orders, much longer than [an] initial 90-day period, is crucial in considering how to handle cost allocation for generating units that are unexpectedly and unnecessarily being retained on the system," ICC wrote in Jan. 23 comments to FERC.

The state commission said given the "volume of DOE 202(c) orders, and the potential harmful impacts on ratepayers across the MISO region, a robust stakeholder process is needed." It said DOE's continued orders to retiring coal plants will "result in significant, but currently unknown costs with unknown benefits." ■

NYISO: Gas Demand Soared Across Eastern U.S. During Fern

By Vincent Gabrielle

New York generators had to rely on oil as gas was scarce throughout the Eastern Interconnection during the Jan. 25-27 winter storm, NYISO *said* in a preliminary analysis that was a last-minute addition to the Installed Capacity Working Group's agenda Feb. 2.

"We wanted to be timely and at least talk about some high-level stuff about what happened last week for folks so we could at least level-set some of the conversation," said Shaun Johnson, NYISO vice president of market structures.

While the storm, dubbed "Fern" by the Weather Channel, caused few disruptions in the Northeast, it had such a large footprint that it affected demand and prices across the East.

"For those of you who are upstate New York natives, last week's weather was cold, but it wasn't extreme New York cold," Johnson said. "The really important part of this is that it was cold in Atlanta."

The weather created high demand for natural gas, causing price spikes that rippled through the market. Downstate generators had difficulty obtaining natural gas at all. Index prices during the winter storm were in the $50 to $200/MMBtu range, with some spot quotes in excess of $300. Average prices are typically much lower, with Johnson citing October 2025's average of $2.17/MMBtu as an example.

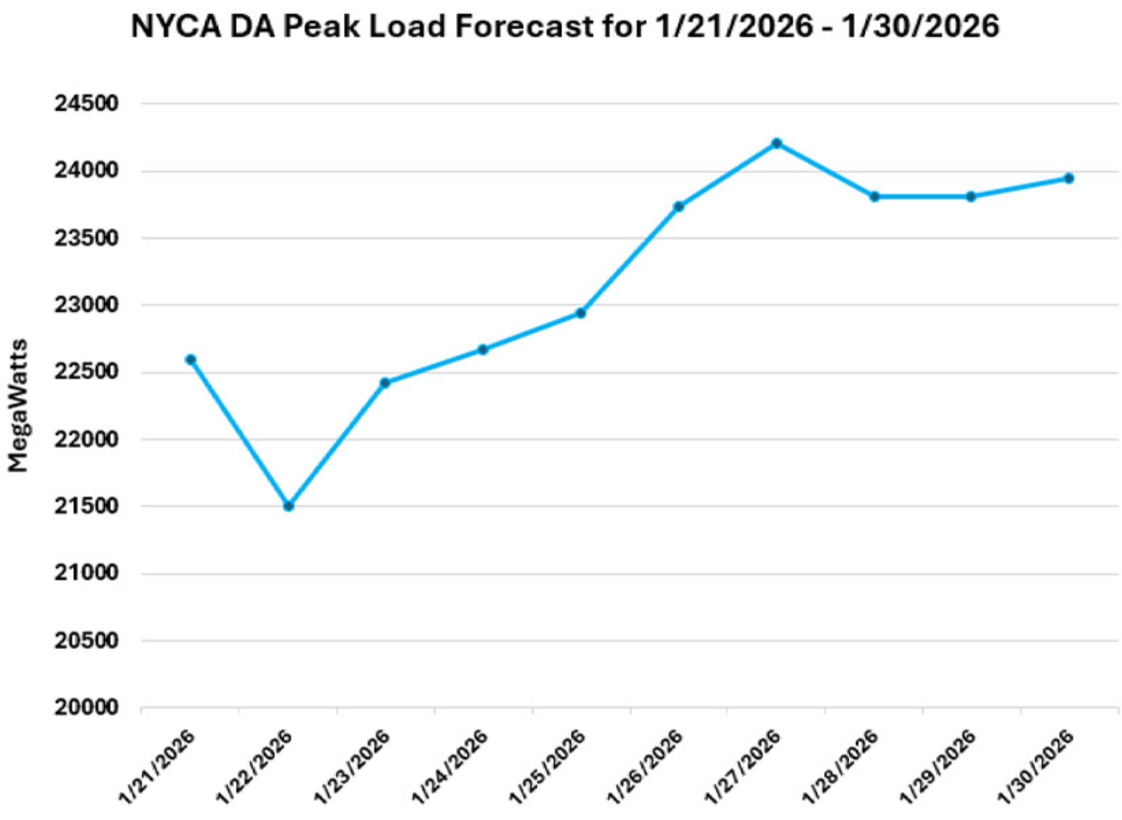
Dual-fuel units shifted to trucked-in oil, which is less efficient than piped gas. Simultaneously, snow on solar panels and overcast conditions prevented solar resources from shaving down the peak load.

"During the first two days of Fern, we went through 20% of our oil inventory in New York," Johnson said. He said the ISO ran its fuel survey multiple times over the week and heard stories of oil-fired generators being continuously served by caravans of tanker trucks "running out the gate" the entire week.

Why This Matters

January saw protracted regional cold weather, leading to price increases in New York. It's a window into future situations where fuel constraints may become more acute.

Johnson opened a map of the U.S. from the National Oceanic and Atmospheric Administration that showed the entirety of New England, New York and most of the PJM footprint under an extreme cold advisory. Cold weather extended southward into Tennessee Valley Authority and SPP territory. Effectively, the entire eastern half of the U.S. was in a state of elevated natural gas and electricity demand.



| NYISO

Johnson cited the NYISO 2025 Gold Book forecast of 24,200 MW of peak load in winter. He said the ISO had come close to that several days the previous week. He displayed a graph of day-ahead peak load forecasts during Fern that plateaued just under the Gold Book forecast for several days.

Additionally, several emergency actions were taken to reduce demand. The Special Case Resource program was activated multiple hours daily Jan. 25 to Jan. 30.

External prices were also extremely high, making it impossible to stabilize prices with cheap imports, Johnson said. ■

N.Y. Reports Minimal Increase in Renewable Power

Renewables Provided Just 23.6% of State's Electricity in 2024

By John Cropley

New York has notched a tiny step forward on its path to a cleaner grid: Renewables provided 23.6% of the electricity provided by load-serving entities in 2024, up from 23.2% in 2023.

But after a decade of intensive policy work and billions of dollars expended, the state's grid was more reliant on carbon-based fuels in 2024 than in 2014, when renewables accounted for 25.3% of the fuel mix, *a new report indicates*.

A key difference is that hydroelectric output in 2024 was 28.6% less than in 2014. Solar output was 898.2% higher in 2024 after that decade of intense policy and financial support, but at 6.8 TWh, it constituted only 4.5% of the system mix.

Why This Matters

The report lays out New York's extensive efforts to decarbonize its grid and quantifies the limited results.

The largest source of carbon-free (though not renewable) electricity for New York is the four commercial nuclear reactors within its borders, which provided 21% of the state's power in 2024.

But there again, progress to a cleaner grid has been elusive: As recently as 2019, there were six operating reactors, and they provided 32.4% of the state's electricity.

As a result, combustion remains indispensable to New York's grids. Natural gas provided 50.5% of the state's electricity in 2024. Trash incineration and imported coal-fired generation each provided 2.1%, while oil, biomass and biogas combined for 0.73%.

The statistics are in the "Clean Energy

Grissom Solar, a large solar array near Johnstown, N.Y. | *NYSERDA*

Standard Annual Progress Report," which the New York State Energy Research and Development Authority (NYSERDA) submitted Jan. 30 to the state Public Service Commission (PSC).

The PSC's "Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard" (*15-E-0302*) dates to 2015. The 2,200-plus documents and 23,000-plus public comments in the case record trace the development of what state leaders would often call a nation-leading clean energy and climate protection vision.

Among those records are multiple indications that following through on the vision has become more difficult than expected, such as when NYSERDA and the Department of Public Service conceded in 2024 that the *state's statutory goal* of 70% renewables by 2030 had likely fallen out of reach. (See *NY Expects to Miss 2030 Renewable Energy Target*.)

More recently, the PSC *began taking public comments* on a Jan. 6 *petition by a coalition of industry groups* urging that the PSC temporarily suspend or modify the targets or provisions of the state Renewable Energy Program under *Section 66-P* of state Public Service Law.

A PSC spokesperson told *RTO Insider* that the commission has made no decision about the petition — it is seeking perspectives and information from different sources on the issues raised in the petition, which is not an uncommon step for it to take.

Underlying the petition and the 2024 NYSERDA report on the Clean Energy Standard is the fact that New York is running short of clean and affordable options for its grid:

- NYISO is *projecting reliability violations* in the New York City and Long Island zones starting in mid-2026.
- Existing transmission and generation assets are aging and need to be expanded if the state is to electrify buildings and transportation and attract industry.
- The governor has directed development of new nuclear generation, which has no recent track record in the United States as a financially acceptable or timely new-build grid asset.
- Solar, which in some ways is a success story in New York's renewable portfolio, presents shortcomings for a state expecting to shift to a winter-peaking grid — winter days here are short and cloudy, and the sun's rays come at a low angle. Large-scale photovoltaic capacity factor *drops to single digits in December and January*; behind-the-meter solar, which accounts for more than 90% of the state's photovoltaic output, is in the single digits in November and in February.
- The renewable power project pipeline imploded in late 2023 amid soaring construction prices; it has been rebuilt only partly.
- Batteries provided just 6,840 MWh in 2024, or 0.0045% of the total 152.1-TWh load.
- The Trump administration and its allies in Congress are working to limit renewables development; the impact already is felt, even as New York fights back on multiple fronts in federal court.
- The state has been counting on offshore wind as a significant component of its carbon-free grid; the two projects under construction off the New York coast have been halted a combined three times by the Trump administration, and developers likely will think long and hard about starting any future projects.
- The state has some of the highest electricity rates in the nation, and there is pressure to not load ratepayers with further costs to support policy goals.
- New York is a slow and expensive place to develop energy, even after progress through streamlining initiatives.

Beyond all this, the NYSERDA report does offer some optimism: Significant new renewable generation came online in 2024, it said, and these facilities' contributions will be reflected more completely in the 2025 report.

More is coming: Seven large-scale projects with a total 1,197 MW of capacity were in some stage of construction in 2024, and work started on 10 projects with a combined 683 MW of capacity in 2025.

Hundreds of jobs and millions of dollars in economic impact resulted from this work.

And there are environmental benefits to decarbonization: The state Department of Environmental Conservation in December 2025 reported that *energy-sector greenhouse gas emissions* were 24% lower in 2023 than in 1990. ■

NYISO, Stakeholders Debate Changes to Demand Curve Reset

Updates on CHPE Integration and Time-differentiated TCCs

By Vincent Gabrielle

NYISO staff presented more of their initial *ideas* for improving the Demand Curve Reset process, centered on alternative shapes, slopes and points of the curve.

The ISO's goal is to simplify the process for both staff and stakeholders. (See *Resetting the Reset: Demand Curve Reform Discussions Begin*.)

"The demand curve is at the core of aligning system reliability needs to market fundamentals," Michael Ferrari, market design specialist for NYISO, told the Installed Capacity Working Group on Jan. 21. "Modifying them can enhance the efficiency of market signals to improve capacity market outcomes."

The DCR shape and slope govern the value of capacity under different market conditions, sending price signals for new resource development and retirement of old units. The more installed capacity that is on the grid, the less any given megawatt is worth, and *vice versa*.

The curve is drawn from the zero crossing point (ZCP) to a reference point set by the cost of new entry and locational minimum capacity requirement. The ZCP is where the marginal price of an additional megawatt of capacity is equal to zero.

Currently, the curve slopes downward from the maximum clearing price plateau in a straight line to the reference point and the ZCP. Ferrari said NYISO had investigated "kinking" the demand curve into multiple slope segments, increasing the steepness of the curve to change prices more rapidly and increasing the ZCP. The ISO also discussed pinning the loss-of-load expectation reliability criteria to losing the largest generation unit in each location, similar to the N-1 contingency analysis in transmission planning.

"We are not trying to indicate an endorsement of any particular change or option," Ferrari said, explaining that the presentation reflected "early analysis" of reform options.

Stakeholders said adjusting the ZCP might be difficult. Howard Fromer of Bayonne Energy Center said the first time the ZCP was set was a heavily negotiated process. Doreen Saia, of Greenburg Traurig, agreed.

Why This Matters

The technical specifics of how the demand curve is shaped and sloped determines how fast prices could change in between resets. This affects how developers calculate their entry into and exit from the capacity market.

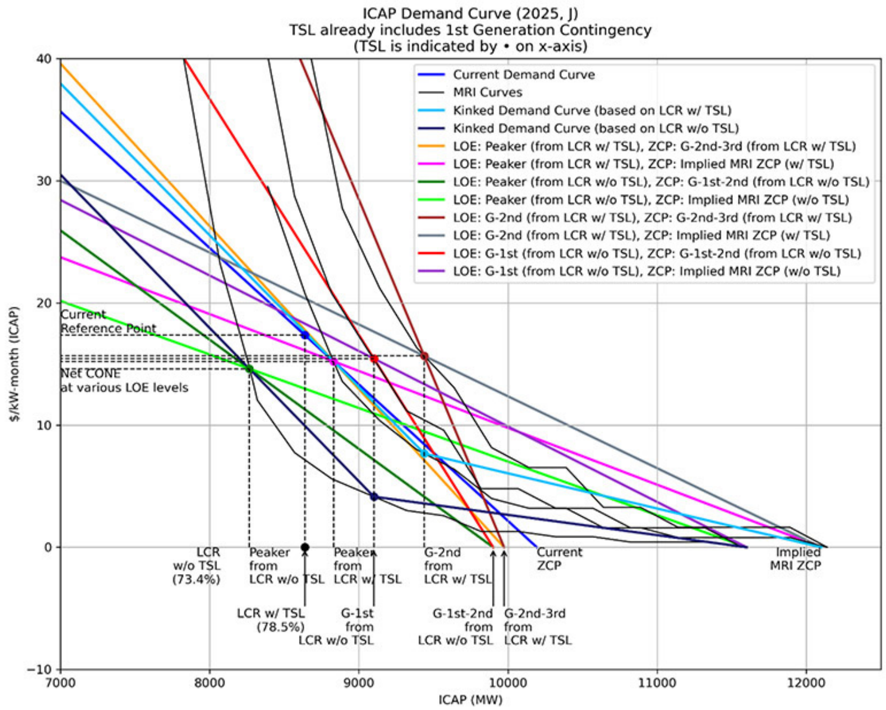
"All of our locality curves have to work within the [New York state] curve," she said. "If you extend out some of the curves too far, it eats into the 'Rest of State' price. … If you go too tight, then New York City gets problematic very quickly."

Saia said that she welcomed looking at the demand curve and ZCP "with fresh eyes" because the situation has become much more complex, from both a regulatory and market player standpoint. More entities of more types are in the market trying to sell power.

One stakeholder mentioned that in the current DCR process, there are provisions to revise the shape and slope of the curve, but in practice this does not happen regularly. Ferrari said the last time he recalled discussing changes to the ZCP was in 2014.

"Mike, I think you're absolutely right," Saia said. "We could have always looked at shape and slope, but for the first six or seven reset processes, the only thing that was even slightly considered was moving to a combined cycle gas facility" for the reference point.

Pinning the LOLE to a contingency analysis based on the largest generator also stirred discussion among stakeholders. Some said this would establish an incentive to build "really large generators" by



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NYISO Pins High Electricity Prices on Global Gas Market

By Vincent Gabrielle

With natural gas being the dominant fuel for electricity generation in New York, rising electricity prices are driven by the increased cost of gas because of the ongoing Russia-Ukraine War and increased LNG exports, according to a recent *white paper* by NYISO.

The paper, released Jan. 29, comes after a week of winter weather and elevated off-peak prices. It relied on the Short-Term Energy Outlooks (STEOs) by the Energy Information Administration and an analysis of electricity prices by Lawrence Berkley National Laboratory.

Prior to the surge in LNG exports, prices remained low because of the shale gas fracking boom of the late 2000s, just as President Barack Obama entered office. Around the same time, Russia began antagonizing Ukraine, culminating in the invasion and annexation of the Crimean Peninsula in 2014. Russia, which also controlled most of Europe's supply of natural gas, cut off supply to Ukraine the same year.

To counter Russia's aggression and lessen Europe's dependency, the Department of Energy under Obama began in 2012 to issue approvals of LNG facilities for exports to countries with which the U.S. did not have free-trade agreements, a policy that continued under Presidents Donald Trump and Joe Biden — though Biden would unsuccessfully attempt to pause such exports in early 2024.

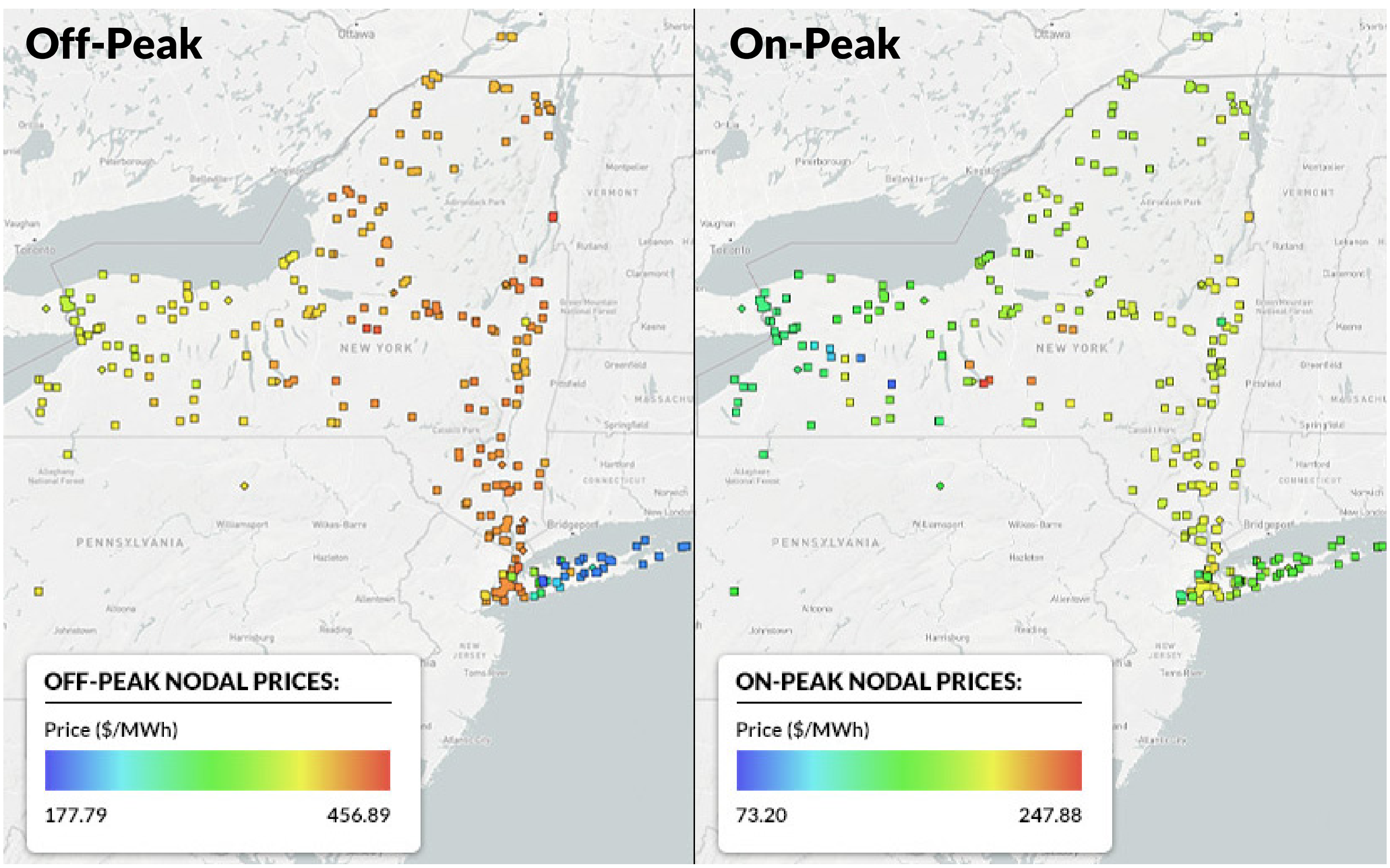
The U.S. became a net exporter of LNG in 2017 and the world's leading exporter in 2023, according to a 2024 *study* at Harvard University. In its STEO for January 2026, EIA noted that LNG exports in 2025 increased by roughly 26% compared to 2024 exports, growing to an estimated 15 Bcfd.

Why This Matters

Amid lower load than expected in the aftermath of the January winter storm, NYISO is facing questions about why energy prices are still so high.

"For context, U.S. residential gas customers consume approximately 12 billion cubic feet of gas per day," the NYISO paper says. "In other words, the U.S. is forecast to export more natural gas than residential customers are expected to consume."

The result has been a strong correlation between gas and electricity prices across the U.S., including in New York. The Transco Zone 6 pricing hub is the primary procurement site for the state's gas fleet.



These maps show on- and off-peak average nodal prices across New York state from Jan. 19 to Jan. 29. Over that period, the average off-peak prices were higher than on-peak prices statewide. | *Yes Energy*

In 2020, amid the COVID-19 pandemic, the price at the hub was $1.64/MMBtu. In 2022, Russia began its full-scale invasion of Ukraine, and exports to Europe — sent over pipelines that run through Ukraine — dwindled. The Transco 6 price shot up to $7.01/MMBtu.

The price for electricity followed the spike, from the record low of $25.70/MWh in 2020 to $89.23/MWh in 2022, according to the paper.

While prices for both electricity and gas fell in the short term, they gradually rose again over the next three years as LNG exports continued to grow. In 2024, gas traded on average at $2.10/MMBtu; by 2025 prices were hovering around $4.64/MMBtu. "The result was significantly higher wholesale prices for electricity as well — with an average price of $74.40/MWh throughout 2025, compared to $41.81/MWh for 2024," the paper says.

The paper was published just after a Jan. 28 meeting of the Budget & Priorities Working Group in which stakeholders asked NYISO staff why energy prices were trading high when load was not near peak.

"We're noticing right now that while the load isn't great, the marginal cost of energy is very high," said Kevin Lang, a lawyer representing the New York City and Multiple Intervenors.

Many stakeholders asked for specifics on hourly pricing, and what facilities on which pipelines were involved in setting daily natural gas prices.

"It's not just as simple as 'Transco 6 day-ahead cleared at X,'" said Doreen Saia, chair of natural resources law at Greenberg Traurig. "There's a lot of factors going on."

In an email, Lang told *RTO Insider* that the white paper did not answer his questions about why energy prices had been surging during periods of low demand, particularly in recent days. According to Yes Energy data, off-peak prices have been on average higher than on-peak prices over the past 10 days.

Barbara Kates-Garnick, a professor of the practice of energy policy at Tufts University and former Massachusetts Department of Public Utilities commissioner, said that rising price trends could be broadly attributed to natural gas prices, Trump's energy export policy and demand.

"Exporting LNG does subject all burns over time to world markets," Kates-Garnick said. "Global natural gas prices were something that we had to become more sensitive to" during her time on the DPU and as undersecretary of energy.

She said the question facing local policymakers is whether to invest in infrastructure or "cobble" solutions together to deal with emergent price spikes.

"We keep pushing this can down the road. Every time it emerges, we address it as if it's a new problem," she said. "It's very frustrating." ■

NYISO, Stakeholders Debate Changes to Demand Curve Reset

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essentially announcing that the demand curve would shift to accommodate them. One said that a contingency in the capacity requirement created uncertainty in developer cost-benefit calculations.

A NYISO staffer argued that using the largest generator had the benefit of greater clarity and transparency for understanding how the market would behave and would not necessarily increase market complexity.

Time-differentiated Transmission Congestion Contracts

NYISO is also considering alternative ways to divide transmission congestion contracts into more granular products.

Currently, TCCs are a 24-hour product only. NYISO is the sole RTO/ISO to offer only 24-hour financial transmission rights. This has been criticized by stakeholders as limiting the effectiveness of TCCs to serve as hedging mechanisms against congestion because they cannot distinguish between congestion patterns that change during the day or over the course of a week.

NYISO considered time-differentiated TCCs in 2021, proposing products for on-peak workdays, off-peak weekends and holidays, and off-peak "all other hours." In 2025, Calpine proposed a system that broke TCCs into on-peak and off-peak hours. (See *Calpine Sees Support for TCC Auction Proposal*.)

The ISO is planning on finalizing a proposal in 2026, building off both its 2021 design and Calpine's. Tariff language will not be pursued until it passes the annual project prioritization process.

Champlain Hudson Power Express Integration

NYISO provided stakeholders with an update on the Champlain Hudson Power Express integration process.

CHPE is a 1,250-MW HVDC line that will run between Quebec and New York City. It is expected to go into service in 2026, but the exact date is unknown. (See *NYISO Proposes ICAP Changes for New Entry Ahead of CHPE*.)

The capacity market is predicated on annual inputs with limited seasonality, and the capability year starts in May. If CHPE's integration into the grid is mistimed, it could have major implications for capacity market parameters, such as the transmission security limit for the New York City-area capacity zones.

To accommodate this uncertainty, the ISO created two sets of market parameters, one assuming CHPE is operating and one assuming it is not. This creates two sets of TSLs, locational capacity requirements, capacity accreditation factors, unforced capacity demand curve parameters and load-serving entity minimum capacity requirements.

If CHPE provides notice by March 2 to participate in the ICAP market in May, NYISO will set the market to reflect its participation. The ISO intends to issue a notice by March 9 to market participants as to whether CHPE will be in the market. ■

NYISO Puts Reliability Planning Under the Microscope

By Vincent Gabrielle

NYISO began what is expected to be a yearlong effort of revising its *Reliability Planning Process* at a Transmission Planning Advisory Subcommittee meeting Jan. 20.

"This is the best opportunity, if you have more concrete feedback, especially any specific suggestions so that we can consider those as we consider revisions before we roll them out," said Ross Altman, NYISO's senior manager of reliability planning.

The existing process uses a single base case to determine whether the transmission system meets all reliability criteria. Base case assumptions are identified in May, finalized over the summer and voted on in fall. The final reliability need assessment is issued in late fall. This goes hand-in-hand with the Comprehensive Reliability Plan (CRP), which considers system conditions a decade into the future.

"The only specific feedback we've received so far to process revisions is to consider a longer horizon," Altman said. "There was a suggestion of 15 years. We welcome folks' thoughts on that."

Altman said the use of base case means the ISO needs to use the most conservative assumptions to account for growing uncertainty across all elements of grid planning. (See *NYISO's 2026 to be Dominated by Reliability Concerns*.) The use of a single base case when reliability margins are tight can mean "flip flopping" between having and not having a reliability need.

Several stakeholders said they were concerned with moving away from a single base case to multiple base cases or scenarios that might trigger a reliability need. Representing Multiple Intervenors, Mike Meager asked Altman to clarify how the ISO would weigh different scenarios or circumstances probabilistically.

Altman said it was difficult this early in the process for the ISO to come up with a "true stochastic" look at probabilities.

"Not declaring needs on outliers is something we're thinking about how to accomplish," Altman said.

He said the process must maintain that reliability needs be based on criteria, and he added that multiple combinations of system conditions could more accurately reflect the changing grid. He stressed that the ISO was committed to "open and transparent" stakeholder involvement in revising the process.

The ISO is planning to review key study assumptions for the 2026 reliability needs assessment study with a particular focus on load uncertainty, aging generation, emergency assistance and generator outage rates.

| Shutterstock

Howard Fromer of Bayonne Energy Center asked how the ISO planned to stick to a 10-year planning horizon for the CRP, given that it was planning on folding multiple forecasts into the reliability process.

"How do we prevent that flexibility you're looking for from swamping the competitive market, which is what we designed to achieve whatever our reliability requirements are?" Fromer asked.

Altman said that was always a risk when using a decadelong planning horizon for a one-year market. He suggested that the issue be separated from short-term reliability needs planning.

Fromer replied that it deserved consideration because the ISO could force a lot of unnecessary infrastructure investment.

Another stakeholder asked whether NYISO would consider changing some of its base case inclusion rules to be more realistic rather than conservative. Meager said he agreed and wanted the ISO to seriously consider how realistic its assumptions are.

"It's not difficult to show some reliability criteria will be violated … if there's no bounds or restrictions or constraints on what assumptions the NYISO can pick and choose to use each year," Meager said.

Altman replied that the ISO is indeed considering the issue.

Alex Novicki, representing Avangrid, requested that extreme weather events be accounted for in the base case because, he said, NERC was going to try to account for them in upcoming resource adequacy standards.

Meager also questioned the ISO's timeline for potential changes.

"What you are contemplating are some of the most significant changes to the Reliability Planning Process we have ever considered, with huge impacts moving forward," Meager said. "There's not a lot of meat on the bones before us right now. The idea that we'd be voting on tariff changes in a couple months is incredibly ambitious, if not highly unlikely." ■

FERC Approves PJM CIR Transfer Proposal

By Devin Leith-Yessian

FERC approved revisions to PJM's tariff to streamline the process for the owners of a deactivating resource to transfer its capacity interconnection rights (CIRs) to a new unit at the same point of interconnection (*ER26-403*). (See *PJM Preparing Alterations to Rejected CIR Transfer Proposal*.)

Replacement resources would qualify for replacement generation interconnection studies in lieu of the full slate of network impact studies new resources must undergo. The replacement resource cannot exceed the maximum output of the retiring unit, and it must interconnect at the same substation bus and voltage. The studies are expected to take 180 days to complete.

Since the CIRs for the deactivating resource already have been studied and the unit included in PJM's system modeling, the commission wrote it is not necessary for a replacement to undergo the full suite of studies to ensure deliverability. The creation of a parallel queue would not constitute queue jumping because the CIRs already have been studied and determined to be deliverable, while the network impacts of a greenfield project are unknown.

The filing is PJM's second crack at creating a fast track for replacement resources after the commission rejected its first proposal in August 2025 because of two carveouts from the proposed requirement that projects be capable of entering service within three years. Those provisions would have created a one-time extension of the in-service date requirement and an exception for resources with long development timelines, which the commission wrote would undermine the purpose of PJM's proposal: bringing replacement resources online faster (*ER25-1128*).

Why This Matters

The proposal is one of several changes to PJM's planning and interconnection processes intended to allow resources to come online more quickly as the RTO seeks to ward off a looming resource adequacy shortfall.

"PJM's proposal permits milestone extensions only in certain circumstances, and only for up to a specific amount of time, which will help ensure that the replacement generation interconnection process results in the timely and efficient replacement of generating facilities. Unlike the prior proposal that allowed replacement generation project developers to unilaterally extend the commercial operation date for their project without restriction, the instant proposal allows PJM to 'reasonably extend' the in-service date or other milestones under specified conditions," the order states, adding that if a developer requires a longer extension, a waiver can be requested from the commission.

Those milestone extensions would be permitted only for "delays not caused by the project developer and that could not have been remedied through the exercise of due diligence," PJM wrote in its transmittal letter. Milestone extensions would be capped at three years past the original commercial operation date.

PJM wrote the proposal is one of several changes to PJM's planning and interconnection processes intended to allow resources to come online more quickly as the RTO seeks to ward off a looming resource adequacy shortfall. Other efforts include the Reliability Resource Initiative, which allowed 51 resources that could quickly add capacity to be inserted into Transition Cycle 2, and expanded eligibility for surplus interconnection service. (See *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

"At a time when PJM needs additional capacity resources in the near term to meet serious resource adequacy challenges, the expedited processing of replacement generation interconnection service requests claiming a deactivating facility's CIRs can yield significant reliability benefits by facilitating the timely addition of new capacity while promoting the efficient use of existing infrastructure," PJM wrote.

The Independent Market Monitor protested the filing, arguing it would

Shutterstock

divert planned resources from the cluster-based interconnection queue to a less efficient serial study process and further slow development by creating an incentive for resource owners to withhold CIRs until they can be sold to a developer.

During the stakeholder process that led to PJM's filing, the Monitor proposed a model under which the CIRs associated with a deactivating resource would be made available to all resources on the grid as transmission headroom. It reiterated the argument that CIRs should not be for sale in its protest. (See "Voting on CIR Transfer Proposals Deferred to October," *PJM PC/TEAC Briefs: Sept. 12-13, 2024*.)

"The basic purpose of the process is to permit existing generators to sell their CIRs to the highest bidder rather than to identify the best replacement resource. The proposal is inconsistent with open access and the purpose of CIRs. A proposal to truly reform CIRs would terminate CIRs immediately at the time a resource deactivates, and thereby avoid undue discrimination, promote competition and facilitate the rapid entry of needed new generation," the Monitor wrote.

The commission wrote the proposal would not implicate market power as the ability to transfer CIRs already is codified in the tariff.

"This filing simply establishes an expedited review process for replacement generation resources interconnecting at the same location as a deactivating generating facility that would not change the voltage or maximum generation output at that location. Nothing in the instant filing would modify the existing rights to transfer CIRs or the transfer process," the order states. ■

SPP Waits on FERC Order to Refund Z2 Credits

Grid Operator Has $147M in Refunds to Disburse

By Tom Kleckner

SPP staff say they still are waiting for an order from FERC before they can begin distributing millions of dollars in compensation to transmission upgrade sponsors from its beleaguered Attachment Z2 process and unwinding billions of dollars in settlements.

The numbers are huge.

The grid operator says it owes about $147 million in refunds, plus an additional $46 million or so in interest to transmission users that made payments under the Z2 process as far back as 18 years ago. It says it also will have to *unwind and recalculate* more than $20 billion in market settlements dating back to 2015 to resettle that Z2 activity.

Only about 1 to 2% of the latter resettlements are related to the Z2 process, staff told stakeholders during a Jan. 26 virtual meeting.

"This will impact both network and point-to-point activities, so if you're a transmission customer or transmission owner, you will be impacted, most likely," said Steve Davis, SPP's settlements manager. "It's a large mountain that we're chiseling away to have a smaller impact."

That mountain has grown to Everest proportions since 2008, when SPP received FERC's approval for its tariff attachment that awards credits to sponsors from upgrade sponsors whose service could not be provided "but for" the upgrade.

The attachment also required the RTO to invoice the charges monthly and to make any adjustments within one year.

However, software problems delayed Z2's final implementation for eight years before 2016, during which the RTO did not invoice any upgrade charges. FERC approved a waiver request to settle more than 365 days in arrears, but in 2019, the commission reversed course and said SPP should have settled Z2 activity from only September 2015 forward. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

SPP General Counsel Paul Suskie has called the Z2 resettlement headache "the most litigated, drawn-out process we've ever had."

The RTO proposed a solution to unwind credit payment obligations assessed under Z2 and made an informational filing at FERC in 2024. In September, the commission ordered the grid operator to make a compliance filing for the proposal. (See *FERC Requires Additional Z2 Filing from SPP*.)

SPP answered with a filing in November (*ER16-1341*). It also issued updated refund balances with accrued interest to entities affected by FERC's remand.

The commission has yet to respond to that filing.

Asked when SPP expects to see the commission's order, Davis said, "I wish I knew, and that's probably the best answer we could give. We would love it to be tomorrow, but honestly, I don't know that we have any indication from FERC."

SPP's Charles Locke reminded stakeholders that FERC's initial order in the proceeding indicated SPP was not to act on the Z2 refunds "until it was specifically authorized to do so by FERC."

Davis said whenever a favorable order comes, "We plan on hitting the ground running."

About a month after FERC's order, SPP will issue final invoices for the refund period. Staff then will complete and deploy an interim Z2 resettlement system and calculate and administer the revised credit payment obligations.

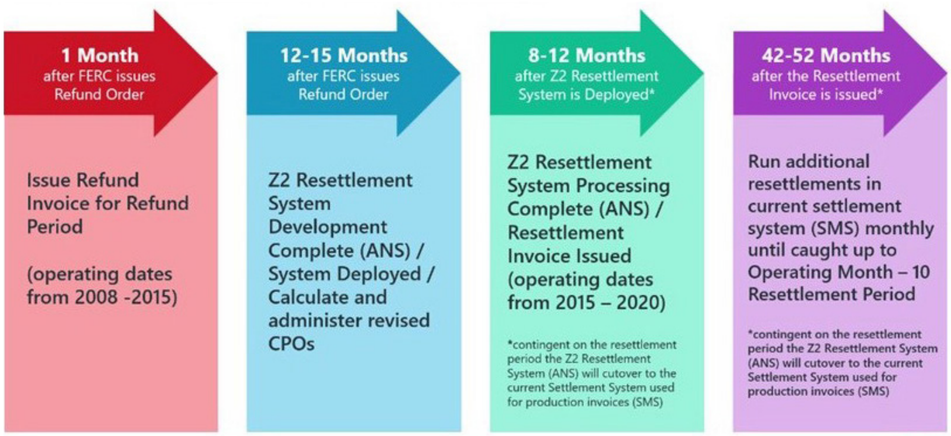
When that process is complete — about eight to 12 months, SPP says — resettlement invoices will be issued for the 2015-2020 operating days. Staff said more than $580 million in Z2 credits have been applied since Sept. 1, 2015; undoing and refunding those historical settlements will require recalculating each operating day since, a process projected to take about two years.

"I keep calling it 'reshaking of the snow globe,'" Davis said. "We have to recalculate inputs into the Z2 process as if the 2009 period through the September 2015 really never happened."

Market participants facing big bills will be able to take advantage of a five-year payment plan, using FERC's interest rate. The commission's rate for the first quarter of 2026 is 7.20%.

At some point, SPP will transition to the current settlement system for production invoices. Additional resettlements will be run on that system monthly, with staff expecting to resettle three historical operating months each month. They expect to be in sync with normal monthly settlements in 2031.

Ironically, SPP no longer uses the Z2 process. Stakeholders recommended, and the grid operator approved, eliminating Z2 credits in 2020 and replaced them with incremental long-term congestion rights (ILTCRs) for new upgrades. The ILTCRs will limit total compensation to each upgrade's directly assigned upgrade costs and interest. ■



The current timeline for SPP's Z2 effort | *SPP*

APS Loses $1.8B Federal Loan Guarantee for Tx, Renewable Projects

Cancellation is Part of DOE's Sweeping Reversal of Biden-era Approvals

By Elaine Goodman

The U.S. Department of Energy has canceled a pending $1.8 billion loan guarantee to Arizona Public Service that was intended to help finance transmission, renewable energy and storage projects.

DOE announced Jan. 22 that its Office of Energy Dominance Financing was revising or eliminating more than $83 billion in "green new scam" loans and conditional commitments. The action followed a yearlong review of the loan obligations from the Biden administration, "including approximately $85 billion rushed out the door in the final months after election day," DOE said. The Office of Energy Dominance Financing is the new name for DOE's Loan Programs Office.

Following its announcement, DOE sent *RTO Insider* a list of projects that had been fully or partly de-obligated and made public. Other de-obligations are underway but haven't been publicly revealed yet, a spokesperson said, and other projects have been de-obligated but not made public.

A project called APS ReCoVR is on the list of projects as a de-obligated conditional commitment. Although the list did not include project details, DOE's Loan Programs Office announced in January 2025 a conditional commitment for an up-to $1.81 billion loan guarantee to APS to help finance new or upgraded transmission, renewable power generation, and grid-integrated energy storage systems.

The first project targeted for financing assistance was Phase 1 of the Agave battery energy storage system, a four-hour, 150-MW project to be built next to an existing solar power plant.

A federal loan guarantee would have supported a battery storage project next to APS' Agave solar plant. | *APS*

Why This Matters

The federal loan guarantee had the potential to reduce costs for ratepayers at a time when APS is ramping up resource acquisition.

One requirement of the program was that savings from the financing assistance would be passed on to customers. The APS loan guarantee was expected to save customers $250 million by reducing the cost of debt.

APS representatives didn't respond to a request for comment.

APS applied for the loan guarantee in November 2023. The approval was conditional, and APS and DOE still needed to work out technical, legal, environmental and financial conditions before it was finalized.

The application came around the same time the company filed its 2023 integrated resource plan with the Arizona Corporation Commission. The plan projected that APS would need to increase its resources from 9,400 MW to 11,350 MW in 2027, 13,000 MW in 2031 and 14,820 MW in 2038. (See *APS IRP Envisions Increased Renewables, Natural Gas*.)

Other projects for which the DOE de-obligated a conditional loan guarantee include the Grain Belt Express transmission line. DOE announced the termination of the $4.9 billion commitment in July 2025, saying federal support for the project was "not critical." The Biden administration issued the conditional approval in November 2024. (See *DOE Pulls $4.9B in Funding for Grain Belt Express*.)

Grain Belt Express, an 800-mile HVDC line, would move a diverse mix of energy from Kansas to Indiana. The Invenergy project could power 50 data centers, the project website said. ■

FERC Approves Duke Proposal to Combine Carolinas Subsidiaries

By James Downing

FERC approved Duke Energy's request to reorganize its utilities in the Carolinas, eliminating a subsidiary of old Progress Energy utilities so the firm will have just Duke Energy Carolinas serving customers in the two states (*EC25-128*).

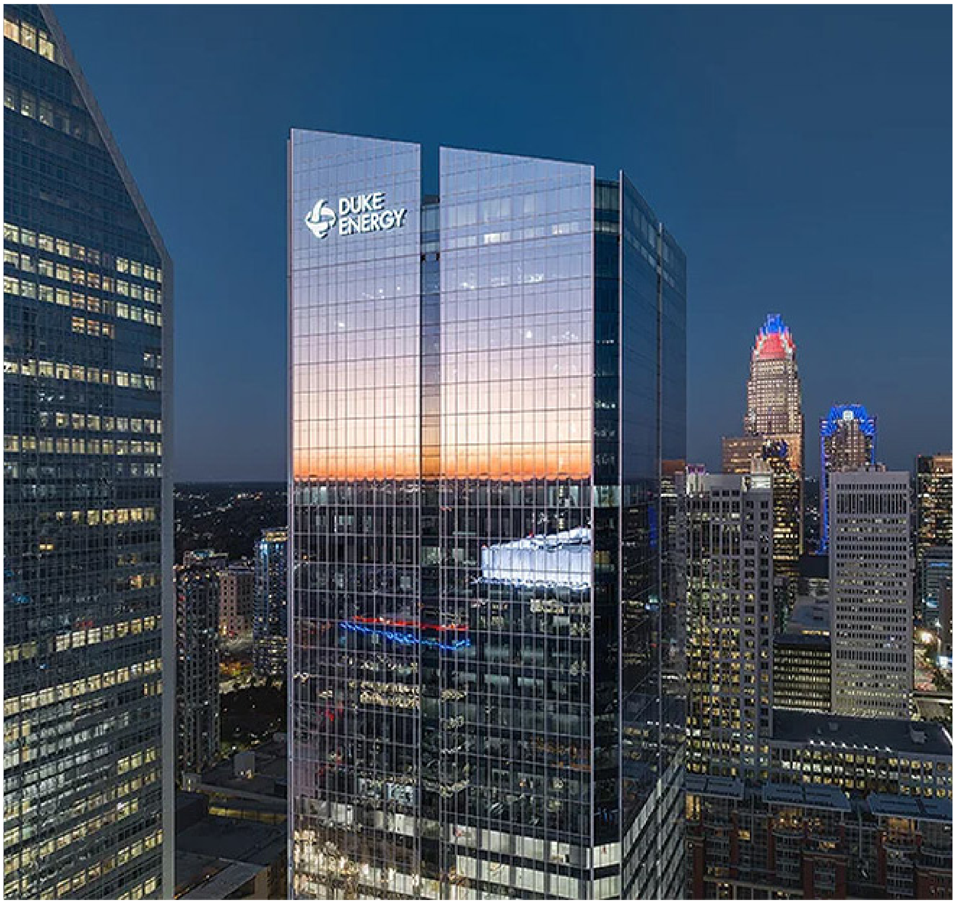
Duke Energy Carolinas has been a vertically integrated utility serving 2.9 million retail customers in central and western North Carolina and western South Carolina. Progress Energy serves 1.6 million retail customers in eastern North Carolina, the area around Asheville and northeastern South Carolina. Duke Energy and Progress merged in 2011, and it has had the two subsidiaries in the Carolinas since then.

Duke asked to combine them because it would make resource planning and operations simpler and more efficient. Over time, Duke claims the efficiencies will save between $1.6 billion and $3.2 billion, said the FERC order released Jan. 30.

FERC found the impact on horizontal and vertical competition would be acceptable under its rules. The only aspect of the filing that was protested was its impact on rates, by a group of wholesale customers including several municipalities and a couple of universities.

Duke's "hold harmless" commitment to customers said it would ensure that any transaction and transition costs that exceed savings from the combination would not affect wholesale or transmission customers for five years.

The protest from the customer group argued that some of the Duke-Progress merger costs were misallocated to customers, which came out after FERC staff audited the deal after it happened. They wanted to see recoverable costs and costs from combining the firm clearly labeled so they could ensure the hold-harmless commitment was upheld.



| Duke Energy

The current system with two subsidiaries means Duke Carolinas' transmission system is sometimes needed to serve Duke Progress customers, and that involves Duke paying some of its transmission customers, the order said.

"Customer group argues that, in contrast, the point-to-point revenues, for which Duke Carolinas' transmission customers receive credit, will disappear, Duke Progress customers will no longer have to pay for the use of the Duke Carolinas transmission system, and the costs that were previously borne by Duke Progress transmission customers will be socialized among all of Duke Carolinas and Duke Progress customers," the order documented.

FERC was not convinced by those arguments, finding the combination of the subsidiaries will not harm rates.

"Under the Share the Benefits Plan, Duke Carolinas' customers will be protected from an immediate rate increase at the cost of deferred benefits by Duke Progress' customers," FERC said in the order. "The separate OATT Mitigation Plan addresses cost shifts impacting transmission customers of Duke Carolinas and Duke Progress, providing a credit to Duke Carolinas' transmission customers over a five-year period, and adopts the lower rate between the two companies when setting ancillary services rates in the future."

The customer group acknowledges Duke's plan will resolve up to 91% of the impact on their rates. FERC declined to eliminate the phaseout of the charges because indemnifying customers in perpetuity goes beyond its merger policies.

"Five-year hold-harmless period is considered 'standard' as the majority of costs incurred as a result of a transaction are in the first five years after the closing of the transaction, particularly in this instance as the merger is between public utilities in the same holding company, and extending a hold-harmless commitment into perpetuity would risk becoming administratively unmanageable," the order said. ■

NextEra Reports Sharp Growth in Generation Portfolio, Backlog

Company Reports Solid 2025 Financials, Predicts Continued Growth amid Power Demand

By John Cropley

NextEra Energy Resources brought 7.2 GW of new generation and storage into operation and added 13.5 GW to its backlog in 2025.

Both were records for the energy infrastructure developer, parent company *NextEra Energy said Jan. 27* as it reported fourth-quarter and full-year financial results.

Looking forward, NextEra Energy Resources expects to bring more than 75 GW of additional capacity online through 2032: 0.6 GW of nuclear, 4 to 8 GW of natural gas, 8.5 to 14.5 GW of wind, 31.5 to 41.5 GW of solar and 32 to 43 GW of storage.

The nuclear addition would be the planned restart of the Duane Arnold reactor in Iowa in 2028 or 2029. The natural gas generation would not start operation until 2030 or even 2032 — a reflection of the delays surrounding new gas turbine delivery.

NextEra Energy utility subsidiary Florida Power & Light (FPL) also had a good year, making $8.9 billion in capital investments in 2025 and planning as much as $90 billion to $100 billion through 2032 to keep up with the state's rapid growth.

FPL has had expressions of interest from developers about more than 20 GW of new large load demand and is in advanced discussions about projects representing roughly 9 GW of demand, which it could begin serving incrementally in 2028.

Each gigawatt would incur about $2 billion in capital expenses, which then would be recovered through FPL's regulated rate of return, which will range from 10 to 12% under a new four-year rate agreement with the Florida Public Service Commission. That agreement also includes a large load tariff to protect existing customers from bearing the costs.

Why This Matters

NextEra continues to expand its portfolio and operating revenue as demand for electricity grows.

"As we enter a new year, we're focused on the opportunity in front of us," NextEra Energy *CEO John Ketchum said* Jan. 27 during a *conference call with financial analysts*. "America needs more electrons on the grid, and America needs a proven energy infrastructure builder to get the job done. That's who we are, and that's what we do."

Ketchum offered other details:

- NextEra Energy Resources is "laser-focused" on what it expects to be the dominant trend in the large load market — bring your own generation — and feels it is uniquely positioned to deliver on this, with its decades of experience, its strong balance sheet and its long-standing relationships across sectors.
- Revenue from certain existing generation assets will be growing — 6 GW of nuclear and renewable power purchase agreements struck more than a decade ago under very different market conditions will be expiring through 2032 and the successor PPAs are expected to command higher prices during re-contracting.
- The company has a partnership with GE Vernova that makes it confident it can secure a supply of gas turbines at a competitive price.
- NextEra views small modular reactors (SMRs) as an important future technology, with potential for 6 GW of co-location with the company's existing large reactors, plus additional SMRs on greenfield sites serving large loads. It has identified about a dozen companies as the most promising among the scores of potential developers in the SMR space, but it does not presently plan any partnerships and will be looking for shared risk and capped financial exposure on any SMR venture it undertakes.

NextEra Energy Resources' Pinal Central Solar is shown in Arizona. | *NextEra Energy*

- NextEra is not sure if it will participate in the upcoming PJM backstop auction — the details need to be finalized, and regulatory and financial certainty need to be in place before such a decision can be made.

"As I look at it, with how we're positioned around [bring your own generation], we have so many opportunities around the United States right now that that we are pursuing, but certainly we have a close, keen eye on PJM as well, and are watching to see how things play out," Ketchum said during the call.

Solid Earnings Growth Expected

NextEra Energy reported fourth-quarter 2025 operating revenue of $6.5 billion and net income of $1.54 billion, or $0.73/share. That compares with $5.39 billion, $1.2 billion and $0.58 in the fourth quarter a year earlier.

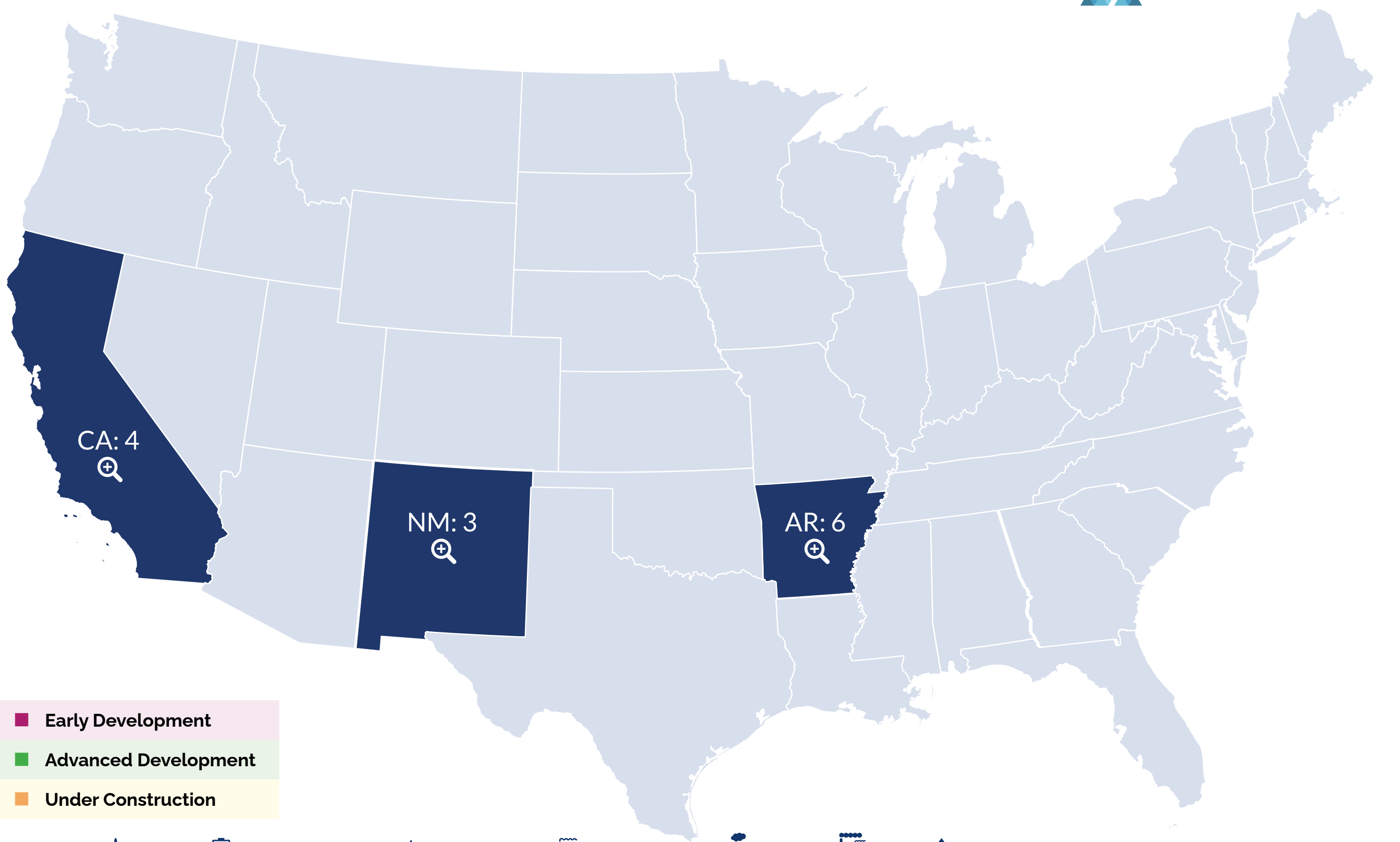
For all of 2025, the company reported operating revenue of $27.41 billion and net income of $6.84 billion, or $3.30/share, compared with $24.75 billion, $6.95 billion and $3.37 for all of 2024.

Adjusted 2025 earnings were $3.71/share, up 8.2% over 2024.

NextEra Energy said it expects adjusted earnings per share to continue to grow at a compound annual rate greater than 8% through 2032 and will attempt to extend that streak through 2035.

The company's stock price rose 1.97% Jan. 27 to close near its 52-week high. ■

Generation Added in the Past Week



Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Coal | Hydro

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
Solar (Early Development)	**Steel River Solar**	Swift Current Energy		AR	500	2031
Energy Storage (Early Development)	**Steel River Solar BESS**	Swift Current Energy		AR	240	2031
Solar (Advanced Development)	**Steel River Solar II**	Swift Current Energy		AR	500	2032
Energy Storage (Advanced Development)	**Steel River Solar II BESS**	Swift Current Energy		AR	240	2032
Solar (Advanced Development)	**Steel River Solar III**	Swift Current Energy		AR	500	2033
Energy Storage (Advanced Development)	**Steel River Solar III BESS**	Swift Current Energy		AR	240	2033
Solar (Advanced Development)	**VEGA SES 1**	Sunpin		CA	100	2026
Energy Storage (Advanced Development)	**VEGA SES 1 BESS**	Sunpin		CA	70	2026
Solar (Advanced Development)	**VEGA SES 3**	Sunpin		CA	60	2026
Energy Storage (Advanced Development)	**VEGA SES 3 BESS**	Sunpin		CA	50	2026
Solar (Early Development)	**Aston Orc 1 Solar ORS1**	Excelsior Energy	Lydian Energy	NM	400	2032
Energy Storage (Early Development)	**Aston Orc 1 Solar ORS1 BESS**	Excelsior Energy	Lydian Energy	NM	200	2032
Solar (Early Development)	**Village of Questa Solar**	Village of Questa		NM	50	2028

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

Dominion Installs 1st CVOW Turbine

Dominion Energy's $11.2 billion Coastal Virginia Offshore Wind project off Virginia Beach's coast reached a major milestone Jan. 21 with the installation of the first turbine.

The tower was installed less than a week after the utility won a preliminary injunction in federal court, allowing it to resume construction on the project.

More: *Virginia Business*

TerraForm Buys 1.56-GW Solar Project in Illinois

TerraForm Power, an affiliate of Brookfield Asset Management, announced the acquisition of a 1.56-GW solar project in Illinois from its original developer, Hexagon Energy.

The Steward Creek Solar project recently sealed a 600-MW interconnection agreement between TerraForm, Commonwealth Edison and PJM.

The financials of the deal were not disclosed.

More: *Renewables Now*

Federal Briefs

U.S. Officially Leaves Paris Climate Agreement

The U.S. officially left the Paris Agreement — for a second time — on Jan. 27, becoming the only country in the world to abandon the international commitment to slow global warming.

The departure from the climate accord comes one year after President Donald Trump signed an executive order to begin the process of withdrawal.

The U.S. is the planet's second-largest climate polluter after China.

More: *The New York Times*; *POLITICO*

FERC Approves Transco Natural Gas Expansion

FERC authorized Transcontinental Gas Pipe Line Company to proceed with its Southeast Supply Enhancement Project,

a major expansion of its existing interstate natural gas transmission system spanning Virginia, North Carolina, South Carolina, Georgia and Alabama.

The order grants Transco authority to construct and operate approximately 55 miles of new large-diameter pipeline, along with significant compressor station upgrades and related facilities.

FERC staff concluded that while construction and operation would result in some environmental impacts, the effects would be reduced to less-than-significant levels with mitigation measures in place.

More: *Pipeline & Gas Journal*

Court Says DOE Climate Group Violated Law

The U.S. District Court for the District of Massachusetts ruled the Department of Energy violated the law when it formed the Climate Working Group.

The court issued a judgment that said the creation of the group, which is composed of five climate change skeptics, violated the law that governs how federal advisory committees work. The Environmental Defense Fund and Union of Concerned Scientists sued the DOE in 2025 for convening the working group without public meetings or notice.

More: *Reuters*

State Briefs

INDIANA

URC Approves I&M Power Plan

The Utility Regulatory Commission approved Indiana Michigan Power's (I&M) latest Expedited Generation Resource Plan.

Under the agreement, I&M will shift its focus from building several new natural gas plants to generation sourced by a mix of gas plants, power purchase agreements, wind, solar and battery storage. The plan also highlights a proposal to develop a virtual power plant program that would allow customers to connect their personal generation to the grid.

I&M says the plan is necessary due since electricity demand is expected to double from 2025 to 2030.

More: *WPTA*

LOUISIANA

New Orleans City Council Bans Data Center Development for 1 Year

The New Orleans City Council voted unanimously to ban the construction of data centers in the city for one year.

The special meeting to consider the future of data center development projects was called shortly after news broke about a proposed data center in New

Orleans East. The ban period will provide the council with time to define data centers and devise a way to effectively prohibit them.

Hours after the council meeting concluded, the developer behind the New Orleans East project pulled his zoning permit.

More: *WWNO*

MAINE

Committee Advances Climate Superfund

The Environment and Natural Resources Committee voted 8-4 to advance a proposal that would establish a superfund for large fossil fuel companies to pay for infrastructure repairs, resiliency efforts and other costs in communities disproportionately affected by flooding and other disasters.

It would cost about $4 million to fully implement the program. Additional staff would also be required, though the exact number would depend on the specific plan.

The bill heads to the Senate.

More: *Maine Morning Star*

MARYLAND

State Further Behind on Emissions Goal than Expected

Modeling done by the University of Maryland's Center for Global Sustainability indicates the state is not on track to meet its mandated 60% reduction in greenhouse gas emissions by 2031.

The data suggest state and federal policies currently on the books will reduce globe-warming emissions only 42% from 2006 levels. The same group of researchers predicted in 2023 that the state would reduce its carbon emissions 50% by 2031 — still shy of the 60% goal set by law, but better than the new estimate.

In a statement, the Department of the Environment said it still has five years to "make smart decisions, do the right thing and take advantage of technological advances."

More: *Maryland Matters*

MASSACHUSETTS

Utilities Back off Plan to Charge Customers Interest

National Grid and Eversource, the state's largest gas and electric companies, said they will forgo all interest on the bill reductions requested by Gov. Maura Healey. Berkshire Gas and Unitil agreed to do the same.

Healey requested the utilities shave customer bills by 10% in February and March amid a second winter of sky-high heating charges and was frustrated the companies had planned to collect interest. Initially, the companies said they would forgive two months of interest but planned to collect the remaining deferred charges with interest up to the prime rate of 6.75%.

More: *WCVB*

MICHIGAN

Consumers Energy Proposes Storage Project on Former Coal Site

The Hampton Township Planning Commission will review a special use permit request from Consumers Energy for a battery energy storage system at the site of the former Weadock coal-fired generation facility.

The $70 million Weadock Battery Energy Storage System would occupy approximately 5 acres and would include a 45-MW storage facility with 36 lithium iron phosphate batteries. The township is already home to part of an 80-MW solar farm on Consumers Energy property.

The commission will hold a public hearing Feb. 12.

More: *MLive*

SOUTH DAKOTA

Eminent Domain Restrictions Advance to Senate

The House of Representatives voted 62-5 to advance a measure that would ask voters to restrict eminent domain in a state constitutional amendment.

The legislation asks voters to approve an amendment clarifying eminent domain "may not be exercised for the purpose of transferring private property to a non-governmental entity solely to promote economic development or increase tax revenue without the provision of a public use." The measure would not ban eminent domain completely.

If the Senate approves the measure, it will go to voters in the Nov. 3 general election.

More: *South Dakota Searchlight*

VIRGINIA

Bill to Boost Local Approvals of Solar Projects Advances

The Senate voted 21-17 to advance a bill that would set up a framework for siting solar projects that localities could follow and prohibit the premature rejection of development.

The bill is not a mandate for localities to approve projects, but it would keep them from outright barring the projects from even applying for permits. Localities would still be able to approve or withhold permits.

The bill now heads to the House.

More: *Virginia Mercury*

WISCONSIN

Kewaunee Site Owner Plans to Restart Plant

EnergySolutions, the company that owns the decommissioned Kewaunee Power Station, said it plans to bring nuclear power generation back to the site.

EnergySolutions submitted a notice of intent to the Nuclear Regulatory Commission on Jan. 15, confirming plans to file for major licensing action for new nuclear power generation at the Kewaunee plant site by June 2028. The plant closed in 2013 and began major dismantlement in 2022.

If the site comes back online, it would be one of only two nuclear facilities in Wisconsin and the first to open since 1974.

More: *Milwaukee Journal Sentinel*