ISSN 2377-8016 : Volume 2026/Issue 6 ▪ February 10, 2026

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ IESO ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

FERC/FEDERAL ISO-NE SPP

DOE Touts Fossil Fuels' Role in Meeting Peak Energy Demand During Storm


© RTO Insider

The Trump administration has been pushing natural gas as a means to meet winter reliability, especially in the Northeast where pipeline constraints require generators to burn oil during cold snaps.

CONTINUED ON P.8

CAISO/WEST

© RTO Insider

Hairston to Retire from BPA, Poised to Join EWEB (p.20)

Hairston's departure would cap an especially tumultuous year for BPA, which is still recovering from the loss of 6% of its workforce because of the Trump administration's buyout offers for federal workers in 2025.

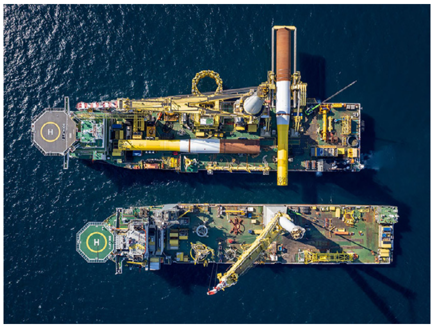
NYISO

Shutterstock

Data Center Moratorium Bill Introduced in N.Y. Legislature (p.43)

Data centers of all kinds account for a large percentage of New York's load growth over the next decade. A moratorium on new construction could impact short-term reliability, electricity prices.

ISO-NE NYISO


Revolution Wind

Revolution Wind Weeks Away from Generating Power — Maybe (p.33)

ISO-NE has said Revolution will be important to reducing reliability risks and NYISO has said Sunrise will help address the capacity shortfall identified in downstate zones.

RTO Insider LLC

YES ENERGY

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

Copy Editor / Production Editor
Greg Boyd

CAISO Correspondent
David Krause

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

Western Correspondent
Elaine Goodman

Western Correspondent
Henrik Nilsson

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Account Executive
Dave Reader

Director, Sales and Customer Engagement
Dan Ingold

Sales Development Representative
Nicole Hopson

Sales Coordinator
Tri Bui

RTO Insider
5500 Flatiron Parkway, Suite 200
Boulder, CO 80301
See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

The Data Center Paradox: NIMBYism Versus Corporate Welfare

By Kenneth W. Costello


Ken Costello

The U.S. electricity sector is at a turning point where after nearly two decades of flat demand, electricity use is projected to surge over the next several years. A major reason is the growth of data centers for artificial intelligence and cloud computing. The country is on the road to build data centers quickly and at enormous scale. AI is a highly critical technology that will shape the future U.S. economy and its place in the world.

State and local government policies to attract data centers seem at odds with many locales opposing the building of new data centers. These policies are offering tax breaks and other inducements to lure data centers, while vocal groups are slamming data centers for various reasons, including their intensive use of land, electricity and water.

In my home state of New Mexico, there is an active and growing opposition to data center projects. For one proposed facility, Oracle's Project Jupiter, opponents of the project raised concerns about electricity consumption and air pollution (especially since it will rely on natural-gas-fired microgrids), scarce water resources for cooling and inadequate public input.

There also is a political undercurrent from both the left and the right that raises questions on AI and the need for data centers, if only because they are owned by Silicon Valley billionaires. As stated in one article, "just like some Democrats are worried they're ceding the anti-AI development lane to Republicans, the same is true on the other side."

We see NIMBYism and corporate welfare at play simultaneously. Each action is misguided by either obstructing the building of new data centers or compelling taxpayers to subsidize them. One challenge is to facilitate the building of new data centers to accommodate AI. NIMBYism can either delay their construction and operation or, worst, terminate their construction. Corporate welfare, besides encouraging wasteful rent-seeking, redistributes wealth from taxpayers to owners of highly profitable data centers.

Why This Matters

NIMBYism and corporate welfare drive up the costs of data centers, delay or even terminate their construction, dampen the benefits to the economy from AI and cloud computing, and unfairly burden taxpayers, writes Kenneth W. Costello.

NIMBYism

Three general problems underlie the NIMBY syndrome. NIMBY projects are facilities that increase overall social welfare but inflict net costs (or at least perceived as such) on the citizens living in the host locality. Data centers seem to fall in this category.

First, the risk perceptions of local citizens may be distorted because of faulty information. Better education of citizens can mitigate this problem. While data centers may increase the price of electricity — which is a major concern of policymakers and activists opposed to data centers — this is not a sure outcome.

Proposals to address this potential problem are numerous and seem plausible if policymakers are willing to implement them. They include:

- allowing data centers to purchase or produce electricity, free of regulation, from facilities off the grid;
- requiring data centers to sign long-term contracts with utilities that include exit fees and minimum billing requirements;
- reforming electricity tariffs to protect existing customers; and
- requiring curtailments or time-of-use pricing of power for data centers during peak periods.

The second problem is that the siting/political process may not mirror a locality's consensus. An active minority of opponents to a facility can dominate the preference of a more passive majority at town meetings or in referenda. This intervention can lead to a decision not representative of the majority preference in the community. The vocal group may be most affected by a facility or have ideological or self-interest reasons for opposing it. The group may perceive no benefits, for example, but only environmental, economic or safety threats from the facility.

The third problem is that the local benefits of a facility may fall short of the local costs. For example, the local area may suffer environmental costs and higher energy costs, while most of the benefits from cloud computing or AI accrue to other areas; a parallel example is the production of shale gas (that emits methane and threatens the local water quality) that benefits out-of-state consumers. Overall, a decision based on faulty information, a defective political process or disregard for out-of-area effects is likely to cause a NIMBY problem.

Corporate Welfare

Corporate welfare (sometimes pejoratively labeled "crony capitalism") refers to government handouts and special protections granted to certain businesses to locate in a specific jurisdiction. Tax breaks, or as some observers call them tax incentives, have in particular become a popular device for state and local governments. Politicians, whether Democrats or Republicans, have relied on tax breaks to attract new businesses. Several states and locales have taxpayer-funded inducements for data centers.

Proponents argue that tax breaks are necessary to attract businesses and that their costs are offset by the additional tax revenue from increased economic activity. They claim that to compete with other jurisdictions, they need to offer tax breaks or businesses will go elsewhere.

Politicians see themselves entangled in a vicious cycle where they are competing with other jurisdictions to attract new businesses. They don't want to appear indifferent to attracting businesses that can bring new jobs and other economic benefits.

What we have seen, with *Amazon* as a prime example (no pun intended), is jurisdictions driving up the tax breaks they are willing to pay to exorbitant levels. Analysts refer to this as the "race to the bottom."

Studies have shown that these giveaways to businesses most times have little effect on their decision on where to locate. Recipients who receive tax breaks often use their political and economic clout to gain favors at the expense of their competitors and taxpayers. It is a classic example of special interests benefiting at the expense of the general public.

At first thought, it seems audacious for government officials to expect poor households and small, struggling businesses to apportion some of the taxes they pay to large, profitable businesses headquartered outside their state or locality (like Meta, Amazon, Microsoft and Goggle). But their behavior shows that they would rather chance a groundless handout than risk being perceived as anti-job and anti-business.

While governments offer handouts with the hope of realizing greater economic returns, companies often make promises to create jobs they fail to keep. Handouts often are no more than a zero-sum game where one jurisdiction benefits at the expense of another.

For many of them, the added revenue from the recipient business falls short of the tax break. While data centers employ many people during construction, relatively *few employees* operate the facilities. Their effect on local economic development arguably is minor.

Tax breaks are just as likely to result in perverse behavior and unintended consequences. They can shrink the tax base, shift tax burdens to other taxpayers or reduce public goods valued by the local citizenry.

Tax breaks also open the door to rent-seeking and corruption: Large companies threaten to locate elsewhere unless they receive special treatment and even "bribe" officials with campaign funds in exchange for favoritism.

Of course, one can imagine situations where a tax break could contribute to the economic well-being of the local or state citizenry net of the subsidy cost. But government officials should make that determination before offering tax breaks to any company.

What we frequently observe is the failure of government officials to provide the public with a transparent accounting of the actual costs of the tax breaks offered to businesses. Most states and localities neglect to fully disclose all the details of their "tax break" packages. A good argument can be made that they should either stamp out tax breaks to businesses or make government officials more accountable for their decisions. Their taxpayers deserve no less.

| Shutterstock

Redressing the Conflict

Real-world experiences have shown the importance of *local participation* in every aspect of the siting process (for example, economic, safety, environmental). Not only should local individuals or groups have the opportunity to participate, but government and industry should encourage them to do so.

Industry acts as a good citizen when responsive to the concerns of local people over a facility that can, or is perceived to, cause substantial harm. Education and public understanding are critical in subsiding opposition and fear and gaining support for a facility. Frequently, the fears are irrational; but the political reality remains that if the public is wary of a new facility in their locality, the owner will need to address those fears or face strong opposition.

One often suggested remedy to the NIMBY syndrome is to shift jurisdiction to a less local authority, such as the state and federal government. Of course, that may have its own problems and should be used only as a last resort.

Instead of tax breaks, governments should create a good business climate with reasonable tax rates and regulations, and pro-growth public expenditures like for infrastructure development. States and locales can better satisfy this goal by broad-based tax cuts than by discriminatory and wasteful tax breaks where they play the role of picking winners and losers.

If governments continue to offer handouts to businesses, they should at least do a cost-benefit analysis. Experience has shown that public officials often understate the true costs of tax breaks and overstate the benefits, which should be no surprise.

For data centers, the two wrongs of NIMBYism and corporate welfare don't make a right: They drive up the costs of data centers, delay or even terminate their construction, dampen the benefits to the economy from AI and cloud computing, and unfairly burden taxpayers. All of these outcomes will harm society, and for what purpose? ■

Kenneth W. Costello is a regulatory economist and independent consultant who resides in Santa Fe, N.M.

ERAS Tour: Hi, It's Me, I'm the Planning Problem

By Simon Mahan

Simon Mahan

Picture this: It's late on a school night and a kid asks their parents for a last-minute trip to the store. There's a project due the next day, and without an emergency run to the market, disaster looms. What follows is familiar: some back-and-forth about how this happened, a short lecture on procrastination and finally a reluctant agreement to make an exception.

Lately, it's hard not to feel like state and federal energy regulators are playing this game, facing utilities that waited too long and now insist everything is urgent.

A clear example is FERC's recent approval of ERAS processes in both MISO and SPP (the Expedited Resource Addition Study and Expedited Resource Adequacy Study, respectively). These new processes allow certain power plants to effectively jump the interconnection line, skipping ahead of hundreds of other projects already waiting their turn. (See *FERC Dismisses Rehearing Ask for SPP's ERAS Process*.)

When ERAS was proposed through stakeholder processes, the underlying rationale was widely understood: Utilities had not planned far enough ahead, particularly for new natural gas plants, and now wanted a faster path forward.

When ERAS was first proposed in 2024, MISO and SPP together had more than 300 GW of generation projects in their queues. The vast majority were wind, solar and battery storage by competitive developers, with relatively little natural gas by the utilities. In fact, MISO's queue grew so large that the grid operator was forced to cap new entries altogether. Yet at the same time, utilities and planners began warning of an imminent reliability crisis.

Integrated resource planning (IRP) processes exist specifically to avoid this outcome. Many utilities conduct IRPs every two to three years to forecast demand and identify future resource needs. Those plans routinely show large additions of solar, wind and battery storage, often alongside some natural gas.

The labyrinth of interconnection studies can take three to four years. Renewable projects often can be built in one to two years once contracted. Natural gas plants frequently take much longer. Utilities know this all too well, yet many failed to submit gas projects early enough to align with their own forecasts.

Now, with electricity demand rising from data centers, industrial growth and electrification, utilities are asking regulators to let them cut in line.

MISO already has received more than 60 ERAS project requests, with nearly three-quarters of the proposed megawatts coming from natural gas. These projects often skip competitive solicitations, too. They are self-identified by utilities as "needed" and advanced on an expedited basis. Entergy alone has submitted more than 8,500 MW of gas generation through ERAS. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

Traditionally, state commissions approve new power plants only after reviewing a full certificate application, including cost estimates, alternatives analysis and transmission impacts. ERAS turns that structure upside down. Under these expedited processes, regulators are asked to effectively bless projects before a formal application is even filed. Once a project receives accelerated interconnection treatment, it becomes far harder to later reject it or disallow its costs.

After all, once you're already standing in the checkout line with emergency school supplies in hand, it's difficult for a parent to say, "You're on your own, kid."

In this case, tens of billions of dollars are at stake.

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

To be clear, ERAS technically is resource neutral. Wind, solar, battery storage, gas and even nuclear projects are eligible. A few have been submitted. But they pale in comparison to the surge of utility-owned, non-competitively selected natural gas plants now racing ahead of the queue.

Fast-tracking these projects risks rewarding exactly the behavior regulators should be discouraging.

So, what can regulators do instead? Here are three practical solutions:

- IRPs must be more than a paper exercise. They provide value only if regulators are actively engaged, assumptions are realistic, load forecasts are transparent and modeling reflects real-world timelines.
- Competitive procurement is essential. Requiring utilities to issue requests for proposals ensures that regulators and consumers can see what the market is offering. Competition disciplines costs. Sole-source generation does not.
- Diversification and transmission expansion must remain central to reliability planning. A grid built around a narrow set of resources is inherently more fragile, not less. Maybe there's merit in a connect and manage interconnection option, like what ERCOT has.

ERAS may be described as a temporary emergency valve, but history suggests that "temporary" exceptions have a way of becoming permanent precedents.

If regulators aren't careful, today's emergency trip won't be the last time.

And that's a lesson ratepayers shouldn't be forced to pay for. ■

Simon Mahan is executive director of the Southern Renewable Energy Association.

Why This Matters

ERAS may be described as a temporary emergency valve, but history suggests that "temporary" exceptions have a way of becoming permanent precedents, writes Simon Mahan.

Tech Companies Need a Hedge Against Worrisome Grid Politics

By Travis Fisher

Travis Fisher

Something strange is happening in American energy policy. U.S. Sen. Elizabeth Warren (D-Mass.) and Florida Gov. Ron DeSantis (R) are worried about the same thing: energy-guzzling data centers. Likewise, Sens. *Bernie Sanders* (I-Vt.) and *Josh Hawley* (R-Mo.) both seem to want an abrupt pause on new artificial intelligence.

Although the Trump administration favors artificial intelligence and data centers, many of the industry's biggest detractors are sure to run for president in two years. And some states, including *New York*, are considering statewide bans on new data centers. Local opposition has long been a thorn in the side of data center development and is *growing*.

A clear political threat to the industry is brewing within both major parties and at all levels of government. What the industry needs is a hedge against bipartisan political risk.

Major tech companies, including *Microsoft*, *Google* and *Amazon*, have announced huge investments in generation assets. *Meta* announced in January that it would expand its nuclear power purchases by 6.6 GW. For reference, that's more than three times the output of *Hoover Dam*.

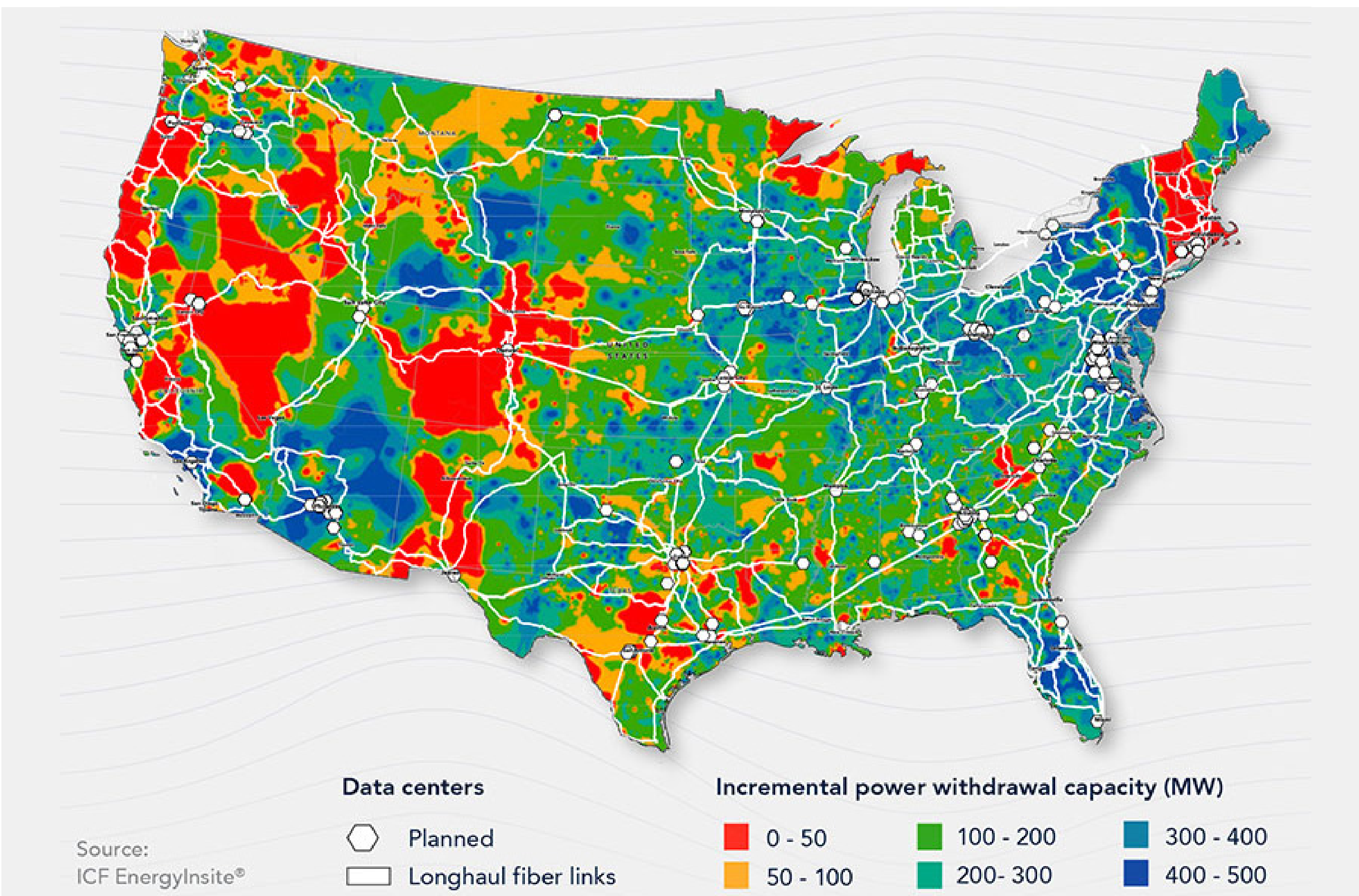
These tech companies' thirst for "juice" is apparent. But what if policymakers don't want them on the grid?

In Warren's recent announcement of an *investigation*, she and fellow lawmakers alleged that "American families bankroll the electricity costs of trillion-dollar tech companies." In Florida, DeSantis and state lawmakers are *proposing* a new suite of regulations on data centers.

More than *230 groups* — including environ-

Why This Matters

Data centers are not the villain, but it may be impossible for them to win the debate in a hostile environment, and the industry would be wise to protect itself against political warfare, writes Travis Fisher of Cato.



Planned data center development overlaid by electric withdrawal capacity and fiber optic networks | *ICF EnergyInsite* mental and consumer organizations — have called for a national moratorium on new data center construction. Dramatic *headlines* such as "AI Is Making Your Life More Expensive" are common.

It matters little that the political alarm over data centers is misguided. In fact, Warren's assertions may be the opposite of the truth. As Nick Myers of the Arizona Corporation Commission recently explained *in RTO Insider*, data centers "provide long-term, stable demand that may reduce the financial risk of utilities and lower their borrowing costs to the benefit of all customers."

Researchers have *found* the "effect of sales growth on rates is highly situation-specific" and largely depends on how new costs are allocated among customer classes. At best, it's a murky policy area that lends itself to political scapegoating.

So, what can the industry do to protect itself from a populist uprising? One alternative is to allow new industrial customers to develop or join a private, fully off-grid energy system. My colleague *Glen Lyons* and I call this idea *Consumer-Regulated Electricity*, or CRE.

Going one step further than typical "behind-the-meter" arrangements with generators, CRE would enable a new, islanded system with no physical connection to the regulated grid. A data center could join many others on an industrial campus powered by whatever resources make sense — solar, batteries, gas turbines, nuclear reactors, you name it — and operate without connection to the utility grid.

Importantly, the lack of a grid connection also means freedom from political meddling. A new proposal by Sen. Tom Cotton (R-Ark.), titled the *DATA Act*, would exempt large users from regulation by FERC. Operating on a separate electric grid means no risk of causing blackouts for American families and businesses. Hence, the onerous regulations that apply to the *"bulk power system"* need not apply to independent facilities.

Like the Trump administration, today's FERC is *supportive* of data centers and their hunger for electricity. However, the industry should be prepared for a one-two punch of reduced *independence* at FERC and a new president who wants to cut off electricity supplies to data centers.

For example, DeSantis recently *said*, "We have a limited grid. You do not have enough grid capacity in the United States to do what they're trying to do." If efforts to expand the grid fail or move too slowly — which seems likely — then the pitchfork mob might come for data centers.

States also can help enable the CRE option and insulate households from rising costs or uncertainty created by data centers. *New Hampshire* has taken the leap, and *Ohio* and *Utah* have enabled private electricity systems.

More states are likely to follow suit now that the American Legislative Exchange Council has approved *model legislation* that would create a path for CRE in any state.

A common critique of CRE is this: "We need AI data centers to help pay for the grid." Yes, the blackboard economics view of grid supply tells us that retail rates should fall for everyone as the total watt-hours on the grid increase and grid utilization improves. But in the real world, risks abound, and no one can guarantee the AI bubble will never burst.

Indeed, the highly uncertain risk to American families of a sharp increase in their utility bills to pay for infrastructure intended for a collapsed data center industry may be unacceptable to some policymakers.

Far from a *"libertarian fantasy,"* private grids already are *being built*, and the data center industry should view policy reforms like CRE as a practical way to hedge political risk. Even if the value seems far-fetched today, why not establish CRE reforms now in case of a future political emergency? Data centers are *not the villain*, but it may be impossible for them to win the debate in a hostile environment, and the industry would be wise to protect itself against political warfare. ■

Travis Fisher is director of Energy and Environmental Policy Studies at the Cato Institute.

DOE Touts Fossil Fuels' Role in Meeting Peak Energy Demand During Storm

By James Downing

WASHINGTON — The U.S. Department of Energy held a news conference to highlight fossil fuels' role in maintaining reliability over the recent winter storm and boast of actions the agency took to bolster the grid.

The U.S. Energy Information Administration *reported* the highest-ever withdrawal of natural gas from storage in the late January week that Winter Storm Fern affected the eastern half of the country, Energy Secretary Chris Wright said at the Feb. 6 event.

"That's a symbol of what increased energy demand came with this storm," he added. "What is natural gas? It's the largest source of home heating for Americans in the country. It's the largest source of electricity generation in the United States."

Fern was larger than Winter Storm Uri, which five years ago led to one of the biggest crises in power industry history when much of Texas lacked power for days and hundreds of people died. Fern's effects on the energy system were much less, Wright said.

While Uri knocked out power to 4.5 million homes largely because of failures in generation and intertwined issues on the natural gas system, just over a million homes lost power this year, primarily from ice-laden tree limbs taking out power lines.

"We wish that was zero," Wright said. "We work and strategize and talk every day about how to reduce that number."

Standing next to bar charts that highlighted how little renewable power contributed to the high demand set by the storm and related cold, Wright argued that the industry needed to focus on installing dispatchable capacity.

"If you want to add to the capacity of our electricity grid, enable data centers, enable us to reshore manufacturing — the only way you do that that's helpful is you have to add to our peak generating dispatch ability," he said.

Wind was down 40% during the peak demand seen during the storm, compared to a more normal weather day last year. Overall, that was true, but intermittency correlates with randomness, and SPP reported that it had more wind than expected, enabling it to ship power east — in a reversal of what happened during Uri, when imports from PJM and other points east minimized its own outages. (See related story, *Wind Output Enabled SPP Exports to Neighbors During Storm*.)

Energy Secretary Chris Wright and Deputy Secretary James Danly at a press conference Feb. 6 held at the Department of Energy's headquarters. | *© RTO Insider*

Why This Matters

The Trump administration has been pushing natural gas as a means to meet winter reliability, especially in the Northeast where pipeline constraints require generators to burn oil during cold snaps.

Solar works better in regions with more sunshine like the deserts in the West, but even then, Wright said, the sun did not always shine, especially when overall energy demand was peaking.

"Peak demand for energy is always in the winter, by far," Wright said. "Peak demand for electricity is sometimes and often in the summer. Because the biggest use of energy in people's households by far is heating, like that winter storm we just went through."

The natural gas distribution network was delivering four times more energy than the grid was at its maximum stress during the recent storm, he added.

But the natural gas system meeting peak household demand when electricity generators also need more power is a dilemma the industry continues to face. (See *Grid Weathers Latest Winter Storm, but Still Faces Gas Coordination Problems*.)

The RTOs in the northeast still are working to procure as much fuel as possible as the cold continues to affect demand, Wright said. As is typical, ISO-NE had to rely on burning oil to make it through, as that fuel produced 35% of power at the height of the storm.

"Where it matters at peak demand time, oil was No. 1," Wright said. "This is crazy. Oil was a huge source of electricity generation in the United States when my mom was in high school."

DOE is working to improve gas-electric coordination, as it has over the past 15 to 20 years, Deputy Energy Secretary James Danly said. The department's National Petroleum Council (NPC) recently released a report making recommendations. (See *DOE's National Petroleum Council Releases Report on Gas-electric Coordination*.)

"The RTOs in the Northeast did their best to procure as much fuel as possible in advance and help their gas generators do that in advance of the weather," Danly said. "It's still ongoing. The temperatures are still cold, but we're seeing, especially in PJM, efforts to get gas out as far as possible, and that's in part with the encouragement of the department and talking with the stakeholders."

NPC recommended making it easier to build more pipelines. A major focus of the Trump administration has been to get the Continental Pipeline built. It needs regulatory approval from the state of New York. The project would bring up to 650,000 Dth per day of Marcellus shale gas to New England and New York. The project won approval from FERC in 2014, but it was blocked by the state of New York.

Constitution has *asked* FERC to reauthorize the project. But unlike the vast majority of pipeline proposals, Constitution did not list any anchor customers, which the commission views as an indication of need in pipeline approvals. Wright argued that the fact that the petition has none doesn't mean it's not needed.

"If a pipeline has been blocked, you know, by the governor of New York, and she says she's going to continue to block the pipeline, people wait for that politics to come out," Wright said. "We will have customers coming out of the woodwork. Do you want to burn far cheaper natural gas versus oil?"

While New England's generation fleet and power consumers would benefit from more natural gas, the vastly different business models make it so generators do not have the incentives to invest in the firm gas contracts pipelines need to secure financing, recently retired ISO-NE CEO Gordon van Welie said during a recent webinar.

"I've also spent … many hours talking to the merchant generators," van Welie said. "And you know, I've come to understand it does not make economic sense for merchant generators to invest in long-term contracts that would be required to ensure adequate pipeline and gas storage infrastructure for these intermittent peaky events, which are low probability. So, they would rather price the risk of non-performance of the gas system into their offers, or financially hedge their risk, or physically try and hedge their risk with dual fueling — if they can get the siting and the permits for dual fueling."

The New England states came to FERC during the Obama administration *asking* to socialize the cost of new pipelines among electricity consumers, but the commission found the idea clashed with the Federal Power Act, and pipelines ran into issues with state politics as well.

"The workaround that was conceived in New England, but never put into effect, was to require the electric distribution companies essentially putting electric ratepayers on the hook for contracting for firm transportation from the pipelines, and then having the EDCs resell that capacity to merchant generators," van Welie said. ■

Rapid Load Growth Focus of State Energy Officials Conference

By James Downing

WASHINGTON — The challenges and opportunities of meeting demand from new large loads like data centers took center stage at the National Association of State Energy Officials' recent Energy Policy Conference.

"I think there's an opportunity right now to think about how the transmission system can be enhanced while we're going through this growth," FERC Commissioner Judy Chang said Feb. 4. "So, there is an opportunity where when large loads come in, it can actually keep rates steady while we enhance the grid."

Regulators could get it wrong and miss that opportunity, leading to higher rates for all consumers, she added. When large loads, potentially paired with their own generation, come online, they will trigger the need to upgrade the transmission system, and it is important that regulators get it right, she said.

Data center developers are flush with cash and have said they are willing to pay their fair share of incremental costs to serve their demand, which in FERC lingo is "beneficiaries pay," Chang said. "So, beneficiaries should pay for the incremental cost of generation and transmission, but if they also are willing to support the system enhancement overall, it could put downward pressure, or at least leveling pressure, on the rates for all."

The biggest item in front of FERC is the Advance Notice of Proposed Rulemaking from the Department of Energy, which asked the commission to assert jurisdiction over large loads to the transmission system.

Historically, states have always overseen the process of connecting new customers to the grid, and they might be putting in new processes, as the number of large loads and their speed-to-market concerns are new phenomena for the industry, Chang said.

Why This Matters

NASEO's conference focused on the main issue of the day and how states and the Trump administration are responding to it.

FERC Commissioner Judy Chang | © RTO Insider

"I'm still trying to understand that current practice and how this ANOPR will respect — I think that's the best way to think about this — how to respect the current practices," Chang said.

How Load Growth is Impacting PJM

Maryland Energy Administration Director Kelly Speakes-Backman recalled that just a few days after she started her job, she received directions from Gov. Wes Moore (D) on working toward ensuring reliability and affordability in the state. (See *Maryland Governor Issues Executive Order on Affordability and Reliability*.)

"As a member of PJM … 40% of our power is imported from states like West Virginia, and so you can imagine that transmission is a very important issue for us that we are facing right now," Speakes-Backman said. "Also, as a member of PJM, we've seen electricity prices just skyrocket."

The executive order Moore signed last year seeks immediate relief to the high prices in the short term, while connecting distributed energy resources in the medium term and building transmission in the long term.

West Virginia wants to be one of the sources of electricity being shipped over the transmission serving Maryland and other importing states in PJM, said Nicholas Preservati, director of the state's Office of Energy. The state already has 40% more generation than it needs, which is exported to the rest of PJM, but load growth forecasts there mean it needs to build many more generators.

"You look at PJM, and they need 100 GW by 2050 to meet peak load," Preservati said. Along with "58 GW coming offline by 2035, there's a real problem that we see."

West Virginia is home to 15 GW of generation, but its 25-year energy plan calls for it to get to 50 GW by 2050.

"People told us we lost our minds," Preservati said. "But when you look at the need and PJM, someone has to do it, and we can't do it all, but we're going to try to step up."

Federal Government's Use of

Emergency Powers

DOE has signaled it wants to stop all coal plant retirements and has used its authority under Federal Power Act Section 202(c) to effectuate that, said Melissa Birchard, director of the Georgetown Climate Center's Mitigation Program.

"Imagine a state that is planning to replace an old, unreliable power plant with a new generator, perhaps as part of the utility's integrated resource plan, perhaps consistent with the large load tariff," Birchard said. "But if there is a 202(c) order in place that is repeatedly renewed, the state can't transition the physical use of the site. The state can't reduce costs for ratepayers by substituting a cheaper plant. They can't free up interconnection capacity [and] grid capacity, which are extremely valuable right now, in order to put something more efficient and more reliable on the system."

DOE has issued six such orders so far, but an additional 23 plants are scheduled for retirement this year, with some with pending retirements in May and others in August, October or December. Those retirements could lead DOE to issue more 202(c) orders to keep the plants open.

After the orders pausing coal plants retirements in Michigan and Pennsylvania, Indiana decided to work with DOE and explain which of its retiring plants made the most sense to keep open given load growth, said Jon Ford, executive director of the state's Office of Energy Development.

Then DOE on Dec. 23 issued a 202(c) order keeping the R.M. Schahfer and the F.B. Culley plants open as an "early Christmas gift," Ford said. (See *DOE Orders Two Indiana Coal Plants to Stay Open Through Winter*.)

"We had really gone through and analyzed all of our coal-fired plants and then provided DOE with a list that — if they were going to do this, here are our rankings of the units," Ford said. "Schahfer was at the top of the list, [but Culley] was at the bottom of the list, so we're not quite sure how they ended up picking" them.

Indiana also asked its utilities to seek grants and work with DOE, which is why Duke Energy decided to keep an existing coal plant running while it builds a natural gas unit, set for completion in 2031, at the same site, instead of at the older facility, he added.

The 202(c) orders came after President Donald Trump issued a Day 1 executive order declaring a national energy emergency, which has been renewed this year. Despite working for the administration briefly, Cato Institute Energy and Environmental Policy Studies Director Travis Fisher said he disagrees with the policy-by-executive-order approach.

"I don't think governing by emergency is a good idea in general," Fisher said. "I will happily eat my hat, though: This past 10 days or so have shown that sometimes that emergency authority is very helpful."

Energy Secretary Chris Wright issued more traditional 202(c) orders during the recent winter storm, while also using the authority to let large customers offer their backup generation be available to meet elevated demand.

"There's all sorts of novel applications that we can do, and some of them are scary. Some of them are terrifying," Fisher said. "I've heard people talk about using 202(c) in a blanket nationwide fashion, to put a moratorium on coal plant closures. That's obviously a terrible idea." ■

FERC Oversight Hearing Focuses on Affordability and Reliability

By James Downing

WASHINGTON — All five FERC commissioners faced questions from the House Energy and Commerce Subcommittee on Energy on how to balance reliability and affordability as demand grows.

"FERC stands at a critical juncture in history, domestically and in the world," FERC Chair Laura Swett told the subcommittee during an oversight hearing Feb. 3. "We're in a global energy arms race created by the rise of technology, its tremendous load growth, and our push to onshore manufacturing and jobs. I want the United States to lead that race."

FERC is working to streamline its processes, cut connection times and ensure efficient, durable infrastructure development, she added.

Why This Matters

The hearing gave representatives a chance to quiz commissioners on the big issues before FERC, including the need to maintain reliability and get prices down for consumers while meeting demand from data centers and other sources of load growth.

The commission's main job is to deliver affordable and reliable energy for Americans while upholding Congress' vision for a bipartisan, independent and resource-neutral regulator, Commissioner David Rosner said. That is easier said than done, especially with all the changes the industries it regulates are facing, he said.

"Our energy systems face these pressures at a time when families and small businesses have been struggling with high prices, including their utility bills," Rosner said. "While meeting this moment presents challenges, it also creates opportunities for us to modernize America's energy infrastructure."

While the demand growth, largely from data centers, does present the opportu-

The House Energy and Commerce Subcommittee on Energy held an oversight hearing on Feb. 3 with all five FERC commissioners attending. | © *RTO Insider* nity to modernize the grid in a way that increases reliability and efficiency, FERC has work to do to make that a reality, Commissioner Judy Chang said.

"To date, the system buildout has contributed to high prices for customers, whose utility rates have already increased in recent years due to other factors," she said. "Thus, as regulators, the commission has a responsibility to guide the industry's efforts towards cost-effective and durable solutions that address these pressing challenges while protecting customers from adverse reliability and cost impacts."

The hearing was held as the district is still digging out from the late January winter storm, and many members of Congress noted it took out power to more than 1 million customers. Ranking Member Kathy Castor (D-Fla.) noted that the storm knocked out some transmission lines owned by the Tennessee Valley Authority. But the bulk power system largely held throughout the winter weather, FERC Commissioner Lindsay See said.

"Though information is still coming in, I'm encouraged to see good results from better winterization and prep work, and coordinating across the gas and electric industries," See said. "We have more to do in these areas, but the progress so far is real."

Subcommittee Chair Bob Latta (R-Ohio) asked his standard question of whether the U.S. needs more power — to which all five commissioners answered "yes" — before asking Swett how FERC is working to ensure regulatory certainty to help that happen.

"We are taking a hard, holistic look at the open items at FERC," Swett answered. "First of all, I shut down quite a few lingering dockets at my first meeting with the help of my colleagues here. That is one way to eliminate uncertainty that has come from previous administrations. Another way is to end the flip-flopping of FERC's regulatory paradigm and the uncertainty that's created by increasing regulation that has built up over the years that far exceeds what FERC's mission is under the law."

Castor asked what FERC was doing to speed up the interconnection of new power plants on the grid.

Chang answered that the commission has been working on that for years, with Order 2023 requiring a first-ready, first-served approach with cluster studies for interconnecting projects. Progress is being made to speed up the queues, she said.

"No matter how fast we can study the projects in the generation interconnection process, one of the bottlenecks I talked about in my opening statement is the transmission system," Chang said. "So, if the transmission system is not ready, or if it's inadequate for interconnecting the generator and the load, that becomes the bottleneck."

Affordability was the focus of many questions, with Swett noting that the aspects of the power system that FERC regulates are responsible for about one-third of the average customer's bill.

"Increasingly Americans are struggling in paying those utility bills," Rep. Alexandria Ocasio-Cortez (D-N.Y.) said. "In 2024, more than a third of households skipped out on necessities to pay an energy bill, and close to a quarter of households kept their homes at hazardous temperatures to avoid the cost of heating or cooling. Yet the energy utilities charging Americans are among some of the most powerful and profitable companies on earth."

She then started asking Swett questions about the average return on equity FERC approves for utilities engaged in interstate commerce. She ran short of time for questions, but later Rep. Greg Landsman (D-Ohio) picked up where she left off.

"Most Americans don't know how much power you all have in terms of adjusting down the profit margin in order to adjust down some of these utility bills," Landsman said.

He asked Swett what kind of debates FERC is having about lowering power bills for consumers considering their ability to trim utility profits.

"The heated debate we are having is a contest to see who can save ratepayers more money," Swett said. "Every time we have a docket come before us, every single one of them has raised, 'Well could we lower this, or can we lower that? How is this going to pass through to consumers?'"

Landsman then asked how quickly FERC could act to lower utility profits by trimming their rates.

"Every single rate that comes before us, we do look at what rate of return the utility has," Swett said. "And that can help Americans, but like I said, that's only one-third of the bill that they pay every month." ■

Pilot Project will Site Small Data Centers Near Stranded Power

EPRI, NVIDIA, Prologis, InfraPartners Collaborate on AI Inference Project

By John Cropley

A new collaboration is *working to develop models* for the faster setup of smaller-scale, real-time data processing centers.

EPRI, InfraPartners, NVIDIA and Prologis will assess the ways data centers in the 5- to 20-MW range can be built at or near utility substations that have available capacity.

The effort was announced Feb. 3 at the *DTECH* transmission and distribution conference in San Diego.

The goal is to speed deployment by making better use of underused infrastructure. The partners hope to have at least five pilot sites in development nationwide by the end of 2026, and develop a replicable, scalable model for wider use.

The focus is on inference data processing, which supports artificial intelligence in nearly every sector of the economy, EPRI said.

Unlike AI model training, which often is carried out in larger facilities over longer time frames, AI inference provides real-time responses and can work from smaller facilities.

When AI inference is distributed, rather than centralized at a single hyperscale facility, it is closer to the end users of data, which can reduce response time.

EPRI said this edge-of-grid distribution also can reduce transmission congestion, improve system flexibility and help integrate renewable energy.

EPRI President Arshad Mansoor said: "This collaboration with Prologis, NVIDIA, InfraPartners and the utility community highlights the type of innovative actions required to meet the moment. Using existing grid capacity to bring inference compute closer to where it's needed — quickly and reliably — is a win for all."

Power industry R&D organization EPRI will identify areas with capacity and fiber connections that could host the pilot projects; later, it will collect and analyze the results to inform future best practices.

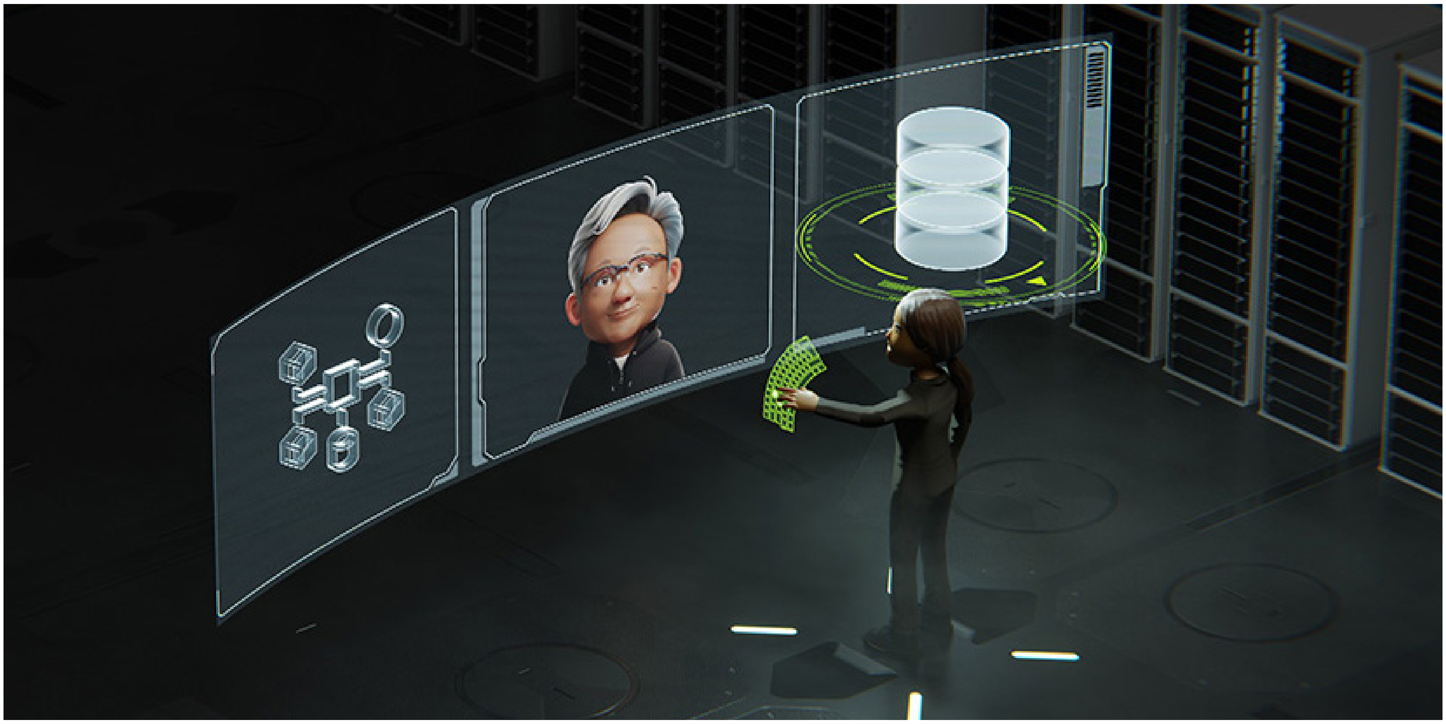
Industrial real estate investment trust Prologis will identify suitable land and buildings that could be used for rapid deployment and will coordinate development and planning.

Graphic processing unit designer/manufacturer NVIDIA will deliver optimized computing platforms, offer technical guidance and facilitate connections to potential customers.

Data center builder InfraPartners will provide AI data centers manufactured offsite and designed for high-density power and cooling.

Participating utilities will assess distribution capacity, guide siting and interconnection, and ensure operational requirements are met.

Marc Spieler, senior managing director for the global energy industry at NVIDIA, said: "AI is driving a new industrial revolution that demands a fundamental rethinking of data center infrastructure. By deploying accelerated computing resources directly adjacent to available grid capacity, we can unlock stranded power to scale AI inference efficiently." ■



NVIDIA's AI data platform is represented in this illustration. | *NVIDIA*

Cleanview: Data Centers' Speed-to-market Goals Lead to Inefficient Gas Generation

By James Downing

Many of the hyperscale data centers being built around the country are using less efficient, dirtier natural gas generation as part of their race to get more computing power online, says a new *report* from clean energy advocate Cleanview.

Some 46 facilities with 56 GW of power demand are planning to build their own behind-the-meter generation, which represents 30% of all planned data center capacity in the country, according to Cleanview research.

"There's been this huge surge in data center demand and data centers wanting to connect to the grid, and that has resulted in the timeline to connect to the grid exploding," Cleanview CEO Michael Thomas said. "It can now take as long as seven years in some markets like Virginia to connect. And then it's also put a huge amount of pressure on turbine supplies."

Just three manufacturers make the most efficient combined-cycle natural gas turbines, and the wait time for them has grown in recent years. Some had thought that combination would throttle data center development, but Thomas said they have found creative ways to get generation capacity with many facilities already under construction.

"What these data center developers are doing is installing gas turbines on semitrucks and driving them in so they can install them in weeks, not years," Thomas said. "They are repurposing aero-derivative turbines that were originally designed for airplanes, warships and in some cases even cruise ships. And then they're using these backup generators and engines that companies like Caterpillar have traditionally sold as backup power to be used a small number of hours in a year, and they're using those essentially 24/7."

Those types of generators are less efficient than combined-cycle plants, and they produce more pollution, whether local pollution like nitrogen dioxide that can make their neighbors sick or climate pollution.

The Stargate Project in New Mexico, being built by OpenAI and Oracle, is about 2 GW and will emit 15 million tons of CO_2 per year.

"Over the last 20 years, New Mexico, as a whole state, has decarbonized its economy by 15 million tons, and they're one of the leaders," Thomas said. "And so that single data center would wipe out all of the state's decarbonization." (According to *its website*, Cleanview's mission is "to accelerate the clean energy transition.")

Massive data center developments using whatever generation they can get their hand is a growing trend. It started in Memphis, Tenn.

"A little more than a year ago, this was just a niche phenomenon," Thomas said. "xAI, famously owned by Elon Musk, was one of the first to do it in Memphis. A few others have kind of experimented with it, but it was really niche. Now it's become one of the most popular strategies. So, 90% of the projects that we identified, representing about 50 GW, were announced in 2025 alone. We've seen this huge explosion in that trend."

The report was based on data from the facilities permits, SEC filings, utility regulatory filings and press releases, though Thomas noted the press releases often focus on cleaner generation and leave out the use of inefficient generators.

Musk's Colossus AI data center was built in an area of Memphis that already was overburdened with pollution, and that led to significant pushback. The NAACP sued xAI over air permits and has launched an effort to fight similar projects as they arise. (See *NAACP Event Examines Data Center Impact on Environmental Justice*.)

Most of the data centers identified in the report are being built in more rural areas, in part to avoid the political pushback encountered by xAI, but also to gain better access to natural gas and an easier permitting process. Only one of the data centers from the report using behind-the-meter generation is in a city, Thomas said.

That data center, in San Jose, Calif., "will be built with Bloom fuel cells, which results in far less air pollutants," he added.

Why This Matters

The gap in timing between new power infrastructure and the speed-to-market demands of data centers is driving the latter to look for capacity from much less efficient, and dirtier, generation than could be provided by new combined cycle plants, let alone renewables and storage.

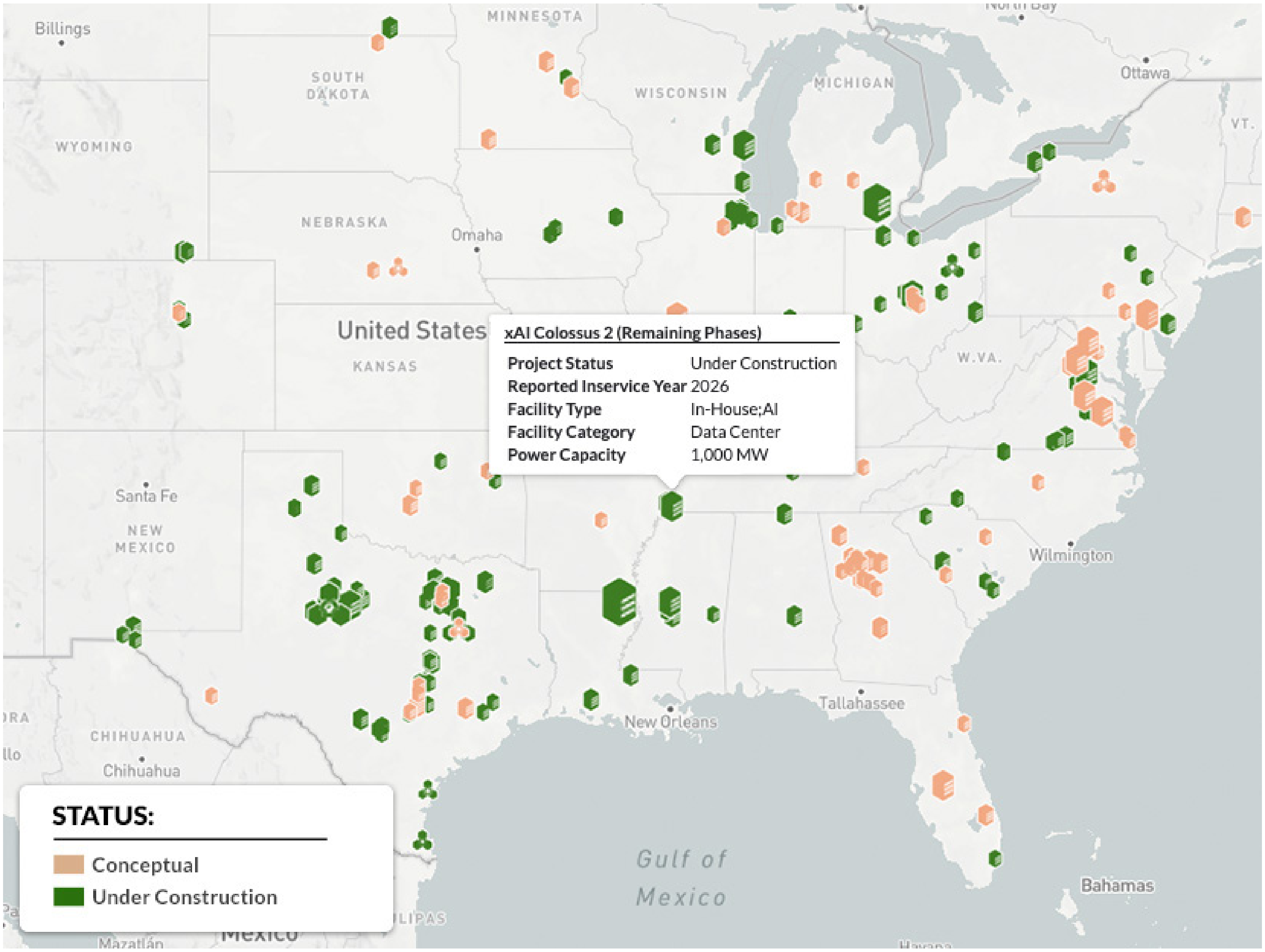
Wind, solar and storage do not face the same kind of timelines as combined-cycle generation, but they do make developments more difficult because of greater land use, Thomas said.

"These are already thousands of acres for the data center alone, and then if you add on top of that, many more thousands of acres for solar and wind data center, developers might be concerned that it's just harder to lock up that land, or it's harder to permit that, or maybe it sparks more backlash," Thomas said.

Across the 56 GW highlighted in the report, there are significant differences in how the data centers plan to relate to the grid in the near term and over time, said former FERC Commissioner Allison Clements. She's now a consultant at 804 Advisory and a partner at Appleby Strategy Group, which advises data center developers.

"For some, onsite generation is intended as a bridge until more reliable grid power becomes available," Clements said. "In any case, the report affirms that the high-octane speed-to-power craze is real, and that substantial capital is willing to pay big bucks and take on stranded-cost risk."

The enduring strength of that demand is uncertain, but utilities would be wise to unlock more capacity on their systems quickly.



A Yes Energy map showing data center projects around the country with xAI's Colossus 2 facility in suburban Memphis, Tenn., highlighted. | *Yes Energy*

"Regulators can support these efforts by moving swiftly to align incentives around fast, lower-cost tools like advanced transmission technologies, rapid battery deployment and portfolios of distributed energy resources," Clements said.

The Cleanview report's findings were highlighted by another close watcher of growing power demand, with Grid Strategies Vice President John Wilson highlighting the report at the National Association of State Energy Officials conference Feb. 4.

Wilson is behind the firm's load forecasting reports, which show up to 90 GW of data centers planned to come online in the next five years, though that could be limited to 65 GW because of chip shortages. (See *Grid Strategies: Pace of Load Growth Continues to Speed up*.)

The Cleanview report shows that many of those data centers are not using the cleanest gas generation, he said.

"Most of this natural gas generation that's going in is not highly efficient, modern gas generation, it is less efficient — whatever they can get, literally generators-on-the-back-of-a-truck kind of generation," Wilson said. "This is what is in their permits."

In five years, the industry could add more data center demand to the national grid than ERCOT's record peak, Wilson said. "A year ago, we were really not looking at this, and now 40% plus of the large load growth is from these gigawatt-scale data centers, 500 MW-plus — mostly AI," Wilson said. "The idea of a gigawatt-scale load was just not something that most utilities considered a possibility five years ago, much less 2, 3, 4 GW at a single location."

Traditionally such major power demands would be served by combined-cycle turbines, but the demand for those has led to lengthy lead times, which clash with the massive financial incentives for data center developers, Thomas said.

"A data center like this, built by developer, can, right now, sell that capacity for between $10 billion and $12 billion per gigawatt," he added. "So, the opportunity of coming online in just six months or a couple years early is huge, and so they're willing to pursue these strange strategies."

AI applications are not making that much money yet, but the firms involved in the industry like Meta or Microsoft are the largest in human history, with massive balance sheets. They worry about being left behind by a potentially major leap forward in technology. They had been sitting on large stores of cash for years, which now are being spent on data centers and related infrastructure, Thomas said.

The trend the Cleanview report put firm numbers around had been picked up by the Energy Information Administration, which recently *posted about* the possibility of using old jet engines from a facility on Davis-Monthan Air Force Base in Arizona colloquially known as "the Boneyard." Data centers in Texas recently deployed modified jet engines as generators that can each produce 48 MW, EIA said.

The engines from the fallow planes at the desert facility could produce a total of 40 GW, which beats the current installed generation in the state of Arizona by 10%, EIA said. But the engines are old, averaging more than a decade, and the military has its own uses for them — so the actual capacity is far less.

The burst of data centers being built with creatively sourced generators means additional demand for natural gas, which increasingly is being exported via LNG and faces higher demand from the combined-cycle plants that also are being built, said Public Citizen Energy Program Director Tyson Slocum.

"The era of cheap gas is over," Slocum said. "All of this new gas, build for power generation, is going to be very expensive."

In 2025, the eight export LNG export terminals used more of the fuel than the 74 million Americans served by natural gas utilities, he added.

So far, data centers have affected power prices most visibly in PJM, where its capacity prices have surged as its reserve margins have narrowed. While supply might catch up to demand and lead to lower capacity prices eventually, Slocum asked how many more billions of dollars that would take.

"I've heard this argument in competitive markets since the beginning — 'Well, folks just need to pay a little more, and then the market will balance itself out,'" Slocum said. "And then right when it's supposed to balance out, they'll say, 'Gosh, we need more transmission.' Or whatever the argument is going to be, there's always some caveat."

If data centers are not part of an AI bubble and LNG exports continue unabated, gas prices will be high, and that translates directly into higher energy prices across the country, he added. Then, laying on the legitimate issues around pollution on top of the costs leads to questions about the value of the "AI race."

"My big issue here is that we've got big tech and their supporters in the administration saying the artificial intelligence race is of national security importance," Slocum said. "Well, says who? Says a bunch of tech companies that stand to make massive profits by commodifying and locking us into their products? We have not had a national conversation about the scope of AI's application in our society or in our economy." ■

ACEEE Urges Greater Efficiency, Flexibility as Grid Demand Grows

New Report Contrasts Costs of Demand Management, New Generation

By John Cropley

Energy efficiency and load flexibility would be effective and cost far less than the new generation assets many jurisdictions are planning to build to meet anticipated load growth, *a new report asserts*.

While both efficiency and flexibility have been cited repeatedly as solutions, they remain underused, the American Council for an Energy-Efficient Economy (ACEEE) *said Feb. 4* as it released "Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth."

Analysis of large utility programs showed energy efficiency with a median cost of $20.70/MWh and load flexibility costing less than $40/kW-year, ACEEE said, while the levelized cost of electricity from renewable, fossil and nuclear alternatives is spread across a much higher range.

The authors note that the cost cited for energy efficiency does not factor in significant avoided costs for distribution infrastructure including substations, transformers and lines. They additionally tout demand-reduction measures as quicker and cleaner than building new generation, as well as better at protecting ratepayers.

There is wide agreement that the U.S. has begun a period of sharp power demand growth, significantly from data center proliferation, but there is no consensus on how steep and high the growth curve will be. The ACEEE report notes that 10-year forecasts of demand growth range from 20 to 50% and peak demand growth from 19 to 35%.

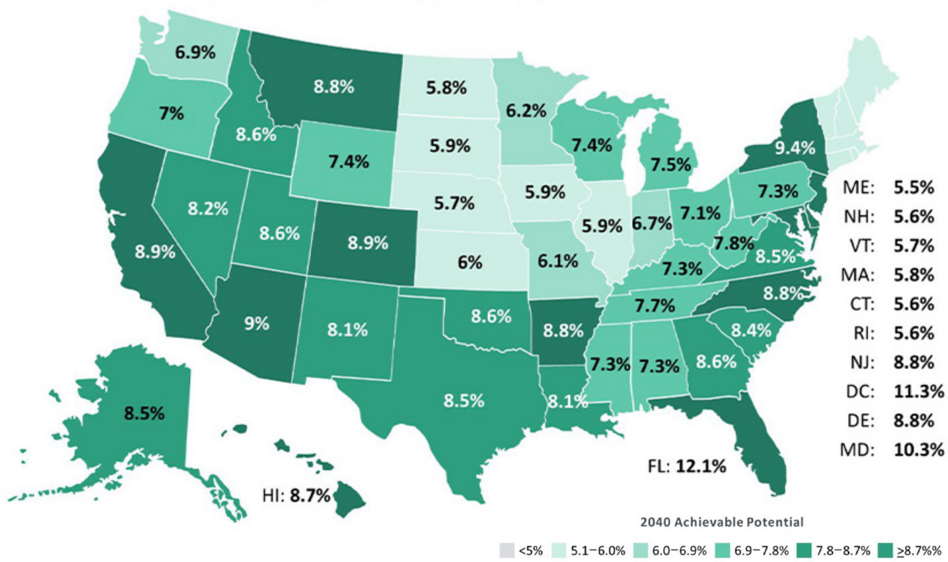
The most common response by utilities has been to plan new gas-fired generation, the authors say, and given utilities' historic tendency to overestimate future demand, this creates the risk of stranded generation, transmission and distribution assets.

Demand-side management in the form of energy efficiency and load flexibility is the better response, ACEEE asserts. Aggregated nationally, energy efficiency could reduce electricity consumption by approximately 8% and demand by about 70 GW by 2040, the report asserts, adding that experts estimate 60 to 200 GW of load flexibility nationwide.

The data center buildout is a once-in-a-career opportunity for the decision-makers in the power sector, many of which get a regulated rate of return on every dollar of investment they make. The Edison Electric Institute *reported* in July 2025 that investor-owned utilities were planning *$1.1 trillion of investments* between 2025 and 2029, significantly more per year than the $1.3 trillion invested in the preceding decade.

Why This Matters

Demand-side management is a potentially significant cost reduction over construction of new grid infrastructure.



The U.S. could achieve an estimated 8% reduction in energy use through 2040 through efficiency measures, with results varying by state. | *ACEEE*

Demand-side management is not a large piece of the solution yet. The ACEEE study notes that only 6% of U.S. energy consumers participated in a retail demand response in 2024. FERC in its *2024 assessment* of DR and advanced metering said participation in the seven U.S. wholesale markets was 33.1 GW in 2023.

A Duke University study in early 2025 found that if data centers would curtail their peak electricity use by just 1%, they could free up 126 GW of grid capacity. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

With its new report, ACEEE is trying to move the needle further, so that more efficient use of existing capacity is considered before expansion.

"Our power system needs to meet rapidly growing electric demand while ensuring reliability and affordability," said Mike Specian, ACEEE utility research manager and lead author of the report. "The first-line approach should be tapping into our massive reserve of energy efficiency and load flexibility, not spending billions on new power plants.

"Demand-side measures are faster and cheaper to deploy today than new generation. They can be targeted to specific locations to defer or avoid the need to build new infrastructure, saving families and businesses money in the process." ■

Tiny U.S. Geothermal Sector Poised for Growth

National Laboratory Report Summarizes Falling Prices, Improving Technology

By John Cropley

The geothermal electricity sector continues its slow growth in the U.S., but the cost of next-generation technology has fallen sharply, setting the stage for wider expansion.

The 99 U.S. plants online in 2024 had a combined nameplate capacity of 3.97 GW, up 8% from 2020, *a new report indicates*.

Over the same time frame, the levelized cost of electricity (LCOE) for conventional geothermal technology held relatively steady at $63 to $74/MWh for flash plants and $90 to $110/MWh for binary plants. With reported geothermal power purchase agreements running in the $70-to-$99/MWh range, the authors say, these LCOEs are considered investable for a firm, high-capacity factor source of electricity.

While the LCOE for enhanced geothermal systems (EGS) remained significantly higher — as much as $200/MWh in 2024, depending on technology — it was close to $500/MWh just three years earlier.

Recent advances could lower the cost of EGS to the level of conventional geothermal technology by the mid-2030s, the authors write.

The details come in the "*2025 U.S. Geothermal Market Report*," issued in January by the former National Renewable Energy Laboratory (NREL) and nonprofit advocacy group Geothermal Rising.

The Trump administration recently renamed NREL the National Laboratory of the Rockies, an indication and reflection of its energy priorities. However, geothermal energy is among the few components of the renewable energy sector *in favor with the current administration* amid its push for more oil, gas and coal combustion.

Why This Matters

The report measures progress toward geothermal energy reaching its potential as a high-capacity-factor U.S. power source.

Work continues on Fervo Energy's 100-MW Cape Station Phase 1 project in Utah. | *Fervo Energy*

Recent advances in oil and gas extraction techniques have brought down drilling costs in that sector. While geothermal drilling remains more expensive than oil and gas drilling, its costs have declined as well, which is important — drilling accounts for 29 to 57% of the total cost of developing a geothermal field, according to the report, which is an expansion of a *2021 NREL report*.

However great its potential, geothermal was a minimally used resource in 2024, accounting for only *15,407 of the 4,308,634 GWh* of electricity generated nationwide in all utility-scale sectors, according to the U.S. Energy Information Administration.

The 8% increase in U.S. geothermal generation from 2020 to 2024 was higher than the *7.4% increase* for all types of utility-scale generation over the same period.

Geothermal nonetheless remained one of the least used technologies — wood and other biomass fuels were burned to make three times as many watts as geothermal generated in 2024.

But the report makes an optimistic case for the potential of the earth's heat to generate more electricity and to heat or cool more structures in the United States.

It indicates the number of geothermal projects in development increased from 54 in 2020 to 64 in 2024 as research improved replicable EGS processes with substantial decreases in drilling time.

As of late 2025, 29 states had enacted geothermal incentive policies, 17 of which encourage geothermal electricity production.

The authors further present geothermal as a component of U.S. energy security and independence: a potential power plant for data centers, a potential option for hybridization with thermal storage and a potential source of critical materials from the extracted underground brine.

A recent analysis by the laboratory estimated 27 to 57 TW of EGS potential at a depth of .62 to 4.3 miles across the continental U.S. Approximately 4.4 TW of that is in areas under federal management, but only about 1% of it would be considered economically developable.

California and Nevada remained the center of the U.S. geothermal sector as of 2024, the sites respectively of 53 and 32 of the nation's 99 facilities. ■

Hairston to Retire from BPA, Poised to Join EWEB

Agency's Administrator in Negotiations to Head up Oregon Municipal Utility

By Henrik Nilsson and Robert Mullin

Why This Matters

Hairston's departure would cap an especially tumultuous year for BPA, which is still recovering from the loss of 6% of its workforce because of the Trump administration's buyout offers for federal workers in 2025.

John Hairston will retire from his position as head of the Bonneville Power Administration, stepping away after 35 years of working at the federal power agency, BPA said Feb. 6.

The development comes just days after Eugene Water & Electric Board voted to select Hairston as its next general manager, though the utility confirmed that no final decision has been made pending further negotiations over a compensation package.

"From the beginning of my tenure as administrator, I have thrived only because I could depend upon the professionalism, skill and resilience of the best federal workforce I have ever encountered," Hairston said in a statement announcing his retirement. "We are a workforce of serious people capable of solving serious challenges. As we navigated turbulence, that capability proved stronger than ever. I have complete confidence in the Bonneville workforce and in our current leadership to guide BPA to continued success on behalf of our customers and the region."

Hairston circulated an internal message to agency staff saying his last day will be April 30, BPA spokesperson Kevin Wingert told *RTO Insider*. Wingert said that while past practice suggests Deputy Administrator Suzanne Cooper would take up the top spot at the agency on an interim basis, such a move has not been confirmed.

BPA said the U.S. Department of Energy is "actively in the process of selecting the next BPA administrator to ensure a smooth process."

EWEB's Board of Commissioners voted Feb. 3 to select Hairston following a nationwide search for a general manager that started in September, according to a Feb. 4 news release from the Oregon municipal utility.

EWEB has yet to make a formal offer and is negotiating Hairston's salary package. If negotiations are successful, Hairston will replace Frank Lawson, who in September announced plans to retire.

"It's an honor for us to have someone at that level with that degree of integrity interested in this position," Lawson said in a statement. "I have a lot of respect for John Hairston."

Lawson's exact retirement date is still open ended, but he's expected to step down sometime this spring, EWEB spokesperson Aaron Orlowski told *RTO Insider*. Negotiations with Hairston are expected to conclude within the next couple weeks, he said.

The final salary package must be approved in a public vote by the utility's board, said Orlowski, who confirmed the posted pay range for the position is $350,000 to $475,000/year. In 2025, the board set Lawson's total compensation at $405,564 annually.

EWEB said in its news release that 18 people applied for the role of general manager, and the board selected two finalists for additional interviews.

"We saw a very clear picture. We saw a very clear vision from both candidates," EWEB Commissioner Tim Morris said. "I think the vision lines up with our mission and vision and values as an organization."

Hairston assumed the role of BPA administrator in January 2021 after former chief Elliot Mainzer left the agency to become CEO of CAISO. Hairston joined the agency in 1991 and worked as chief operating officer and chief administrative officer. (See *Hairston Appointed BPA Administrator*.)

Hairston has guided BPA through significant decisions both for the agency and the region. For example, following a lengthy and sometimes heated stakeholder process, BPA decided in May 2025 to join SPP's day-ahead market option Markets+ instead of CAISO's Extended Day-Ahead Market. (See *BPA Chooses Markets+ over EDAM*.)

"John Hairston has been a courageous, steady and principled leader for the Pacific Northwest as our industry has faced tremendous challenges," SPP CEO Lanny Nickell said in a statement. "I'm very grateful for John's leadership in advancing Markets+ as a solution that promotes increased reliability and affordability for the West. I look forward to partnering with BPA and his successor as we work together to power progress for Western consumers."

Under Hairston, BPA paused certain transmission planning processes and launched the Grid Access Transformation project to tackle an unprecedented interconnection queue. The most recent study includes 61 GW of new generation, compared with 5.9 GW in 2021. (See *BPA Tx Planning Overhaul Prompts Concern for Northwest Clean Energy Compliance*.)

Hairston's departure will come after an especially tumultuous year for BPA on the staffing front. Like other federal agencies, BPA in 2025 confronted an exodus of experienced employees after the Trump administration offered federal workers buyouts and imposed a blanket hiring freeze — despite the power marketing administration's status as a self-funding entity. (See *BPA Employees Confront Trump's 'Fork in the Road'*.)

BPA lost about 200 workers — 6% of its workforce — and rescinded 90 job offers because of those policies. As of late 2025, BPA was still looking to fill 155 positions after its hiring freeze was lifted. (See *BPA Looks to Fill 155 Positions After Hiring Freeze*.)

"John Hairston has been a steady, principled leader for BPA during a period of real complexity and change," said Scott Simms, CEO and executive director of the Public Power Council. "On behalf of public power utilities across the Northwest, I want to thank John for his service and for his commitment to keeping BPA and its talented workforce focused on reliability, affordability and its core public mission." ■

BPA to Revamp Public Involvement Policy

Changes May be Coming to Public Comment, Noticing Procedures

By Elaine Goodman

Forty years after adopting a public involvement policy, the Bonneville Power Administration is reviewing the document with an eye toward modernizing it.

BPA held a workshop Feb. 3 to start gathering feedback on the 16-page *policy*, issued in 1986.

"It is quite aged. There are things in it that are not really part of how anybody does business anymore," said Kim Thompson, BPA's vice president of Northwest requirements marketing.

The policy was written before the arrival of spellcheck, and one task will be to correct typos.

At the same time, BPA wants to rewrite the policy so it holds up in coming years despite changes such as technology advancements.

BPA wrote the policy in response to requirements of the 1980 Northwest Power Act. The policy applies to "major regional power policy formulation." It also allows for varying levels of public involvement on issues such as transmission, renewable resources, energy conservation, and fish and wildlife.

The public involvement policy exempts certain other processes, such as ratemaking and major resource acquisition, which follow their own specific procedures. The policy also preserves the BPA administrator's discretion to react quickly when warranted.

BPA plans to review the 1986 document's definition of "major regional power policy," as well as the list of exemptions. Tariff changes under the Federal Power Act are a possible new exemption.

Why This Matters

The public involvement policy lets stakeholders and the public know how they will be informed of actions BPA is considering and ways to take part in decision-making.

BPA is reviewing its public involvement policy, which dates back to 1986. | *BPA*

Another area for review is the best method for publishing notices of intent. Depending on the situation, BPA might publish a notice in the *Federal Register*, mail it to landowners or use another means.

One workshop participant said it would be helpful to Bonneville's "core audience" if notices were included in BPA tech forums — an email distribution group — even if they're published in other ways.

Another attendee asked if notices could include links to relevant documents so stakeholders could get a head start on reviewing materials.

A section that's being eyed for deletion pertains to public comment forums, in which members of the public gather to comment on an issue in person. A verbatim transcript of the forum is then prepared to be added to the record.

Although BPA still occasionally holds a public comment forum, written comments have become the standard.

The 1986 policy specifies a 30-day window for submitting written public comments, a period that allowed for mailing materials back and forth, BPA representatives said. Even though comments may now be submitted more quickly by electronic means, workshop participants seemed to favor keeping the comment period at 30 days.

"It's not just about the time it takes to review and write comments," said Fred Heutte, senior policy associate with the NW Energy Coalition. "Many organizations have internal processes that they have to go through to respond to an important formal proposal by Bonneville."

BPA plans to hold at least one additional workshop on its public involvement policy. A draft policy would then be released in early April followed by a public comment period. BPA hopes to finalize the policy around July 1.

Feedback on the scope of policy changes may be submitted by Feb. 11 to *communications@bpa.gov*. ■

West Needs $60B in Transmission Ahead of 2035, WestTEC Finds

Group's Anticipated 10-year Outlook Finds Significant Upgrades Needed

By Henrik Nilsson

The West must build or upgrade 12,600 miles of transmission at a cost of about $60 billion to meet the region's forecast 30% increase in peak demand and other needs by 2035, according to the Western Transmission Expansion Coalition's 10-year outlook.

The anticipated 30% increase in peak electric demand — from 168 GW in 2024 to 219 GW in 2035 — is more than three times greater than what the region has experienced over the past decade, according to *WestTEC's 10-year outlook* for the Western transmission system released Feb. 4.

WestTEC, an initiative of the Western Power Pool (WPP), anticipates a 35% increase in energy consumption and a 71% increase in generation capacity over the same period.

Meanwhile, transmission expansion is expected to increase from approximately 98,000 miles of 230-kV transmission lines to about 111,400 miles in 2035, or 14%, according to the 10-year outlook.

"I'm not saying that transmission has to keep up one-to-one with load growth," Keegan Moyer, a partner at Energy Strategies and consultant for WestTEC, said during a presentation in connection with the release of the report. "I don't think that's necessarily true. But we definitively know that it can't grow by half. And it can't grow at a third of the rate that we're adding in generation. This study proves that."

Data centers and "the electrification of everything in our lives" are driving the forecast increase in peak demand, according to Moyer.

WestTEC has put together a portfolio of planned and newly identified transmission expansion projects that would meet this forecast demand through 2035. The total portfolio is estimated to add or upgrade 12,600 miles of high-voltage transmission at a cost of about $60 billion.

The report notes that the $60 billion is manageable when considering that the annualized cost of the projects is "eight times less than the cost of generation that must be added over the same time horizon and represents only 2.5% of today's average retail electric price in the West."

The portfolio includes 73 planned projects that total about 9,400 miles at a cost of $46.6 billion, about 20% of which are already under or close to starting construction.

"Reconductoring and rebuild projects represent about 10% of planned transmission in terms of both line miles and costs," according to the report. "If these sponsors do not complete these in-flight projects, the total transmission gap will grow, and needs identified in this study will not be met."

WestTEC identified an additional 3,300 miles of upgrades needed to address reliability, deliverability and efficiency concerns.

The group said the portfolio would enable the Western grid to address the 30% growth in electricity demand and reduce the risk of outages by addressing more than 75 "steady-state power flow violations on the high-voltage system that would occur but for the construction of upgrades identified by WestTEC."

The portfolio would cut power production costs by $500 million/year, with grid congestion costs and generation curtailments falling by 20% and 17%, respectively.

"These metrics are inherently conservative and do not reflect the full extent of savings and efficiencies that could occur," according to the report.

The identified projects could allow an additional 10 GW of power to move across key regional interfaces during critical periods, lowering shortage risks and reserve requirements, per the report.

'Admirable Achievement'

Several projects under the Bonneville Power Administration's $5 billion Grid Expansion and Reinforcement Portfolio are listed in the WestTEC study.

For example, the Lower Columbia to Nevada-Oregon Border project is on the list. The project is 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. (See *BPA Provides More Details on $5B Tx Projects*.)

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

BPA has been a "proud partner working with the Western Power Pool to support the creation of WestTEC," BPA spokesperson Kevin Wingert told *RTO Insider*. "We are one of many participants across the Western utility landscape to participate in WestTEC's 10-year horizon report."

"We believe this first-of-its kind, West-wide study identifies necessary transmission infrastructure additions needed to enhance grid reliability, increase efficiency and facilitate the integration of new resources," Wingert added. "We appreciate the broad range of regional stakeholders in identifying emerging transmission needs across the Western Interconnection. This study provides actionable recommendations for the implementation of new transmission that will address congestion and unlock inter-

> **Notable Quote**
>
> "I'm not saying that transmission has to keep up one-to-one with load growth. I don't think that's necessarily true. But we definitively know that it can't grow by half. And it can't grow at a third of the rate that we're adding in generation. This study proves that."
>
> *— Keegan Moyer, Energy Strategies*

WestTEC identified a portfolio of transmission expansion projects that meet the region's forecasted needs through 2035. | *Western Power Pool*

regional transfer capabilities."

Several CAISO projects are similarly included in the list of planned projects in the WestTEC study, such as the 260-mile Humboldt-to-Collinsville 500-kV line. The line is part of CAISO's 2023/24 transmission planning process. (See *FERC OKs Abandoned Plant Incentive for Calif. Offshore Wind Tx Developer*.)

"The ISO is very supportive of a coordinated West-wide transmission plan for the next 10 and 20 years, and looks forward to future West-wide analysis and planning, including the 20-year West-side transmission plan," Jeffrey Billinton, director of transmission infrastructure planning at CAISO, said in a statement. "The 10-year plan affirms the planning and approvals that are already underway in California and the West, and sets the table for more interregional transmission development in the next two decades."

Brian Turner, senior director at Advanced Energy United, called the WestTEC study an "admirable achievement."

"These upgrades don't just address the increasing reliability risks in the region, they address the very important need for transmission to connect and deliver the massive new power the West needs for economic development, demonstrating that transmission is a critical component of our nation's need for speed to power," Turner said in an email to *RTO Insider*.

The WestTEC effort, jointly facilitated by WPP and WECC, addresses long-term interregional transmission needs across the Western Interconnection. The release of the 10-year planning horizon report comes after 18 months of work, Moyer noted. (See *WestTEC Targets Early 2026 for Release of 10-year Tx Outlook*.)

A 20-year horizon report is slated for release later in 2026.

The main objective of WestTEC is to create an "actionable" transmission study by conducting integrated planning analysis across the Western Interconnection.

The study horizons focus on evaluating transmission requirements in 2035 and 2045, with the goal of prioritizing "flexible and scalable transmission solutions for nearer-term needs to help better position the system for efficient long-run expansion," the study plan says. ■

Pathways Asks CAISO to Kickstart ROWE Funding Discussions

Launch Committee Seeking to Cover $8M in ROWE Startup Costs

By Henrik Nilsson

The West-Wide Governance Pathways Initiative's Launch Committee asked CAISO to initiate a stakeholder process to create a funding mechanism for the newly incorporated organization that is to assume governance over the ISO's energy markets.

In a Feb. 3 *letter*, Launch Committee co-Chairs Kathleen Staks (Western Freedom) and Pam Sporborg (Portland General Electric) asked CAISO CEO Elliot Mainzer to facilitate discussions about creating mechanisms for ISO market participants to cover the debt financing costs for the Regional Organization for Western Energy's (ROWE).

"We have received generous financial support from stakeholder and philanthropic contributions but will need additional funding for the ROWE implementation efforts," Staks and Sporborg wrote.

The Launch Committee seeks approximately $8 million to fund ROWE's implementation costs until the organization can collect funding from members starting in 2028. The $8 million will go toward seating an initial board, hiring key staff and consulting support, according to the letter.

So far, the committee has collected about $1.1 million in stakeholder contributions and grants. To cover the rest, the committee is exploring debt financing with commercial banks "that could be repaid by market participants in 2028 after the anticipated transfer of governance of the markets to the ROWE," the chairs wrote. (See *Pathways' ROWE Incorporated in Delaware, Board Search Underway*.)

"The commercial banks would require ROWE to have a way of guaranteeing repayment of the loan," according to the letter. "Therefore, the Launch Committee is requesting [that] CAISO facilitate a stakeholder process to develop a proposal to create a funding mechanism for the ROWE's debt financed startup costs that would be repaid by market participants."

Wind farm near Palm Springs, Calif. | *Shutterstock*

CAISO spokesperson Gary Delsohn told *RTO Insider* in an email that under a straw proposal issued by CAISO, the ISO would provide credit backing for a commercial line of credit for ROWE. Beginning in 2028, when ROWE is scheduled to assume governance over markets, CAISO will recover ROWE costs through surcharges on participation in the markets, enabling ROWE to repay the bank.

"The ROWE would be responsible for making payments on the loan after January 2028, with the CAISO serving as guarantor," Delsohn said. "This is necessary because the ROWE at that point would not be able to obtain such credit until it has become more established. The ROWE would draw upon the loan on an incremental basis throughout the start-up period to cover initial start-up costs."

"This approach ensures an equitable and broad-based sharing of the ROWE's start-up costs among market participants throughout the regional market footprint, including market participants effectively utilizing the ROWE within the CAISO Balancing Authority footprint and throughout the [WEIM and EDAM] regional footprints," he added. "The rate and collection mechanism would be set forth in the CAISO's tariff and thus subject to approval by FERC."

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 in the Western power sector see as a barrier to wider participation in CAISO-run markets by ensuring they are not governed primarily by officials and stakeholders in California.

ROWE was incorporated in Delaware on Jan. 21. The organization is to assume governance over the markets in 2028. ■

Fight Heats up over Colorado's Craig Coal Plant Extension

State Energy Official Questions Rationale of DOE Order

By Elaine Goodman and James Downing

WASHINGTON — A federal order to keep Unit 1 of the coal-fired Craig Generating Station operational past its planned retirement date seems "completely disconnected from any of the actual realities on the grid," a Colorado state energy official said at a conference.

"It really does feel like it's sort of unprecedented times as we try to figure out how, as a state, we can meet the needs of our residents, while trying to figure out how to work with new realities at the federal level," said Will Toor, executive director of the Colorado Energy Office. Toor spoke Feb. 4 during the National Association of State Energy Officials' Energy Policy Outlook Conference in D.C.

The U.S. Department of Energy on Dec. 30 ordered Tri-State Generation and Transmission and other Craig Station co-owners to keep Unit 1 operational through March 30. Unit 1 had been slated for retirement on Dec. 31. The *order*, issued under Section 202(c) of the Federal Power Act, said emergency conditions existed due to increasing demand and shortages from the accelerated retirement of generating facilities. (See *DOE Blocks Retirement of Another Coal-fired Plant*.)

Challenges to the order have been filed separately by Tri-State, the Colorado attorney general and a coalition of environmental groups. DOE has 30 days to respond; if there's no response, the request is deemed denied.

Why This Matters

Members of Tri-State Generation and Transmission Association may be left footing the bill for repairs, maintenance and fuel supply as the DOE orders Craig Unit 1 to remain available for operation.

Although the order was for 90 days, some are concerned that it will be extended through additional emergency orders, as has been the case at locations including the J.H. Campbell coal-fired plant in Michigan. (See *DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open*.)

Toor noted that the Unit 1 retirement had been planned for 10 years. Recent assessments have shown that the Rocky Mountain region has no elevated energy risks through 2035, "so there's no energy emergency here," he added.

Coal Supply Issues

At the time of the order, Craig Unit 1 had been out of service since Dec. 19 due to the mechanical failure of a valve. The Craig Station co-owners took steps to repair the valve, and the unit was available to operate by Jan. 20, according to a Tri-State release.

But Toor pointed to other issues for Craig Station, where the other two units are scheduled to retire in 2028.

Tri-State has "just enough coal left" in its mine to run the units until their retirement date, Toor said. Because they're not set up for rail delivery of coal, it would be difficult and expensive to buy coal elsewhere.

"They can't actually produce 1 kWh of additional electricity because they have to use the same coal supply," Toor said.

Although the faulty valve at Unit 1 has been repaired and the unit has been available to operate, it has not actually been in operation, a Tri-State spokesperson told *RTO Insider*.

Tri-State declined to provide details of the cost to keep Unit 1 available. Toor estimated the cost would be around $80 million a year.

Tri-State is a nonprofit power supply cooperative, and concerns about costs to its members prompted it to request a rehearing of the order on Jan. 29. Platte River Power Authority, one of the Unit 1 co-owners, joined Tri-State in the filing the petition.

"We have planned for the retirement of this resource for over a decade and have proactively replaced the capacity and energy from new sources," Platte River General Manager and CEO Jason Frisbie said in a statement. "While Platte River will continue to comply with federal law, we disagree with the need to keep the plant open."

The *petition* claims that the order is an uncompensated taking of the parties' property and disrupts their "carefully considered reliability planning." The order also failed to consider reasonable alternatives, the petition said.

'Fake Emergency' Alleged

Tri-State's filing came a day after requests for rehearing from Colorado's Attorney General Phil Weiser and a coalition of environmental groups.

Weiser's *petition* argues that Section 202(c) does not give the DOE general regulatory authority over resource adequacy, which is the purview of the states and FERC.

The order provides "no facts that would support a determination that Craig Unit 1 is the 'most advantageous' way to address the alleged emergency," Weiser's petition said.

A *petition* for rehearing filed by environmental groups Jan. 28 makes similar arguments, and says the order doesn't address shortcomings of Craig Unit 1 including an unreliability that will likely worsen. The petitioners include the Sierra Club, GreenLatinos, Vote Solar, Public Citizen and the Environmental Defense Fund.

"The federal government has manufactured a fake emergency to revive a coal plant that was literally broken at the time DOE claimed the plant is needed," Colorado Sierra Club Director Margaret Kran-Annexstein said in a statement. "Trump's actions benefit coal executives at the expense of everyday people."

The environmental groups said they plan to challenge the order in court if DOE denies the rehearing request. ■

Western Market Seams Complicate Data Center, Clean Energy Investments, Panelists Say

By Henrik Nilsson

As the West appears to move toward two separate day-ahead markets, data center developers like Google and clean energy companies are investing with the intent to mitigate seams and ensure operational consistency, panelists at an Advanced Energy United webinar said.

Representatives from Google, Leap Energy and Pattern Energy discussed the newly incorporated Regional Organization for Western Energy (ROWE) during a Feb. 3 webinar in conjunction with the release of a new AEU *report* on the advantages of a unified Western market.

ROWE is expected to assume governance over CAISO's energy markets — the Western Energy Imbalance Market (WEIM) and soon-to-be-launched Extended Day-Ahead Market (EDAM). (See *Pathways' ROWE Incorporated in Delaware, Board Search Underway*.)

The West-Wide Governance Pathways Initiative created ROWE as an independent organization to remove what some see as a barrier to wider participation in WEIM and EDAM by ensuring they are not governed predominantly by officials and stakeholders in California.

However, EDAM is not the only day-ahead market under development. Despite ROWE, a significant number of entities have opted to join SPP's Markets+, which is scheduled to go live in 2027. (See *BPA Outlines Next Steps in Markets+ Implementation*.)

For Google, the split between EDAM and Markets+ could make moving clean energy "complicated and expensive," according to Sydney Henry, the company's data center strategic negotiator.

Pattern Energy

"This fragmentation will make specific clean firm projects financially unviable if we have to cross market borders to reach our key investments, in this case, likely our data center investments," Henry said.

One issue is the market seams that will arise between EDAM and Markets+. The seams are created by different policies and separate dispatch between neighboring markets, which can result in additional costs for transferring energy across the boundary.

Google now looks at its data center investments in the context of how markets are likely to be structured and how to mitigate seams risk by, for example, ensuring that power purchase agreements are "in the same market or within the same structure as the data center," she said.

"That's always opportune, because then they're operating under the same rules and the same constraints," Henry said. "So, it's both an opportunity and a bit of a risk mitigation effort as we continue to see how the different states land and the different utilities land within their preferences. But I think it would definitely be preferable, from our perspective, to have it as regionalized and stable as possible."

Meanwhile, independent governance reduces seams costs and regulatory friction, which is important for large-scale energy investors like Google, Henry noted.

"We are investing in new markets," she said. "This isn't investments that we were maybe seeing five or 10 years ago in the couple million dollars. It's now billions of dollars of investments."

Resource Developer Challenges

Jack Wadleigh, senior regulatory and market affairs manager at clean energy developer Pattern Energy, likewise said the "multi-market landscape" introduces challenges for both existing projects and meeting contractual obligations.

Changes to Pattern's settlement points within the markets for resources that are "pseudo-tied or dynamically scheduled" can significantly impact developers, Wadleigh said.

Notable Quote

"We are investing in new markets. This isn't investments that we were maybe seeing five or 10 years ago in the couple million dollars. It's now billions of dollars of investments."

— Google's Sydney Henry

"And these issues are kind of ongoing, especially when we talk about things like congestion, revenues and whether you're settling with the market operator or settling with the balancing area," he said. "So, these are all kind of high-priority topics for Pattern as we're thinking about the future state as we go into a world with multiple markets in the West."

Instead of having a standardized approach, market fragmentation forces providers to adapt to the different markets' bidding rules, timelines and performance metrics, according to Collin Smith, regulatory affairs manager at Leap Energy.

Smith sits on Pathways' nominating committee as a representative of the distributed energy resources sector. (See *Pathways to Engage Broad Set of Stakeholders to Select Independent RO Board*.)

Leap's operations are "largely limited to California because of the difficulty of integrating across multiple different types of participation in other states."

"If you are creating multiple markets across the region, you're just slowing down the ability for companies like Leap to be able to operate in those areas and make use of the different technologies that are already being adapted by customers across the West for their own purposes … losing the ability for those to be quickly integrated into the grid," Smith said. ■

CAISO Examines 'Pulsating' Data Center Loads

Possible New Stakeholder Initiative Needed to Address Impact of Large Loads

By David Krause

CAISO wants to ensure grid reliability when artificial intelligence data centers "pulsate."

A pulsating load can occur at AI training data centers after servers in the facility complete large computations. When these computations have finished, "all the load drops significantly, 80 to 90%, within seconds," CAISO staff member Ebrahim Rahimi said at a Feb. 5 large load information session hosted by CAISO.

"That nature of the AI training comes with a number of potential issues," Rahimi said. "The main thing is we don't want a [grid] disturbance to happen and all the large load data centers drop off and stay off. They [could] have a large impact on the system frequency and voltage."

As observed with AI training data centers, pulsating load levels can trigger critical dynamic system frequencies and force system oscillations, Rahimi said. These effects can cause resonance issues with nearby rotating machines, he said.

The Feb. 5 information session was intended help CAISO determine whether it needs to make certain policy changes for large loads. If policy changes are required, the ISO will begin a new stakeholder initiative.

"Currently, we don't have a threshold for what constitutes a large load," Danielle Mills, CAISO infrastructure policy development principal, said during the session. "So that is something that we'll both take comments on and may develop over the next several months."

Why This Matters

Data center loads have been at the forefront of national electric grid concerns over the past year, and CAISO is now reviewing its own processes to see how to better account for the increasing number of large loads in California.

Utilities are responsible for large load interconnections, but CAISO is monitoring developments at the federal level regarding whether RTOs and ISOs can or should be more heavily involved in the process, a Jan. 30 CAISO Large Load Considerations issue *paper* said.

Cost allocation rules for large loads could be particularly complex, especially rules for co-located load and generation facilities, the paper says. Often, it will be impossible to tell whether load or generation affected networked facilities, the paper says.

"As electric regulators are fond of saying, cost allocation 'is not a matter for the slide rule,'" the paper says. "Enhancing large load cost allocation rules and responsibilities will thus require significant coordination across tariffs, including the ISO's."

Currently, CAISO includes large loads in its annual transmission planning process, and in recent years it approved projects to provide increased capacity in the Bay Area to support data center load growth, the paper says.

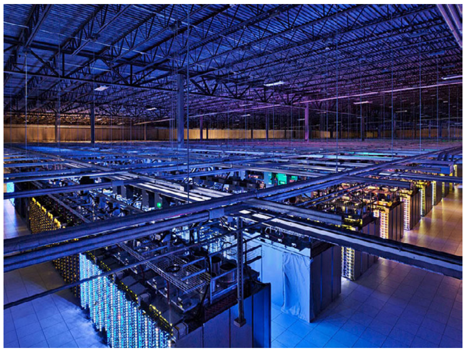
CAISO might develop new technical standards that govern large loads — an effort that resembles the NERC project to consider new technical standards for large loads, the paper says.

CAISO is looking also for ways to allow large loads to participate in ISO energy and ancillary service markets more efficiently.

At the information session, one stakeholder asked if the focus of the paper is to see whether large loads can be made flexible.

"Flexible loads are a consideration, but we also have a parallel initiative going on right now — the demand and distributed energy market initiative — that is looking probably in more detail at flexible loads," Mills said.

In July 2025, the California PUC partly approved a new rule to make it easier for AI data centers and other large customers to complete transmission connection projects in Pacific Gas and Electric's territory. PG&E's retail customer transmission



| Google

interconnection demand has increased by more than 3,000% since 2023, utility representatives said. (See *CPUC OKs New PG&E Rule to Speed Tx Connections for AI Data Centers, Others*.)

Large Loads Forecast

California's data center load could increase by 1.8 GW by 2030 and by 4.9 GW by 2040, according to the California Energy Commission's demand forecast.

But large loads include more than data centers: Loads from EV charging stations and electric agricultural and industrial equipment, which also fall into this category, are expected to increase significantly over the coming years too.

EV charging load is forecast to be about 2.4 GW at the peak hour in 2030 and about 7.8 GW in 2040, the CEC forecasts. These amounts represent about 5% of the system's load at peak in 2030 and about 13% of the system peak in 2040, the CEC told *RTO Insider*.

Charging for electrified agricultural equipment such as tractors, specialized mobile equipment and all-terrain vehicles at farms would constitute approximately 16 MW at the peak hour in 2030 and about 51 MW at peak in 2040, the CEC said.

The agency requests updated data from the state's investor-owned utilities and other utilities three times per year. It uses the data from the first request to develop the draft energy demand forecast, the second to finalize the energy demand forecast, and the third for additional details that inform the dataset it develops for CAISO's transmission planning process. ■

EDAM Town Hall Highlights 'Pivotal Moment for the West'

Seams Issues Must be Addressed for Reliability Purposes, CAISO Says

By David Krause

CAISO leaders staged a virtual "town hall" to stress the importance of a smooth rollout to the ISO's Extended Day-Ahead Market in May and promise to address market seams issues.

"This is clearly a pivotal moment for the West," CAISO CEO Elliot Mainzer said during the Feb. 4 event. "We have the opportunity to … drive further reliability and affordability benefits."

EDAM is scheduled to launch in 2026, with PacifiCorp and Portland General Electric as its first two participants. As of late 2025, both utilities were on track to join EDAM on their planned entry dates in spring and fall, though the schedule is considered tight and aggressive. (See *'Aggressive' EDAM Schedule 'Going Smoothly' for PacifiCorp, PGE*.)

CAISO recently entered parallel operations with PacifiCorp, and Mainzer said both entities are "very excited" to take that step.

CAISO Vice President of Stakeholder Engagement Joanne Serina said stakeholders are "really at the heart of everything we do here at the ISO."

"We have been on a journey to ensure stakeholder engagement," Serina said. "We've been working on an approach … to create a stronger, more meaningful role for stakeholders."

Why This Matters

CAISO is about three months away from rolling out its Extended Day-Ahead Market, but it will still confront many issues — such as seams complications — after launch.

© RTO Insider

Serina reminded the audience that CAISO introduced stakeholder working groups into the scoping and development phases of initiatives at the ISO. This approach has further strengthened the stakeholder process by inviting stakeholders to provide comments directly, she said.

CAISO wants to remain "nimble" with stakeholder initiatives as EDAM begins. A high-priority initiative in 2025 dealing with congestion revenue allocation rules is an example of that nimbleness, Serina added. (See *CAISO's EDAM Scores Simultaneous Wins at FERC*.)

CAISO COO Mark Rothleder focused on the importance of transmission connectivity as EDAM launches. The resource diversity in the West and strong transmission connectivity in the ISO's real-time Western Energy Imbalance Market (WEIM) "helps us all at different times in different ways," Rothleder said.

"The seamless transactions have also been tremendously successful in supporting grid reliability," Rothleder said. "When one area of the footprint … is facing reliability concerns, another area of the footprint can seamlessly deliver energy through transmission and the market to help manage grid conditions."

A larger market will have even more opportunities to enhance reliability and deliver economic benefits, he added.

"Increasingly, we have tremendous reliability benefits from seamless operation of WEIM crossing large, geographically diverse footprints," Rothleder said. "Without the seamless operation of the market and efficient utilization of the transmission connectively, results of [extreme weather events] would have looked much different."

EDAM extends market optimization to the day-ahead time frame, where the bulk of scheduling occurs as the market efficiently positions the resources to serve the forecasted demand across the footprint, Rothleder said.

"We anticipate the EDAM market design will continue to evolve [and be] informed by stakeholder input and by operational experience," Rothleder said.

CAISO recently completed the EDAM market simulation phase with PacifiCorp. The market simulation phase is the pre-production testing phase, where EDAM technologies are available for market participants to test and evaluate.

No 'Plug-and-play' Solution for Seams

The number of energy entities committed to or leaning toward EDAM represents about 50% of the load in the West, Rothleder said.

However, with some WEIM participants intending to leave the market to join SPP's Markets+, coordination across market seams will be necessary, Rothleder said.

In the West, seams arrangements "should build upon the foundation of existing operating agreements and standards and procedures used to maintain reliability for the region," Rothleder said. "Specifically, any new agreements must preserve system reliability, account for emergency conditions and be compatible with NERC and WECC requirements."

Participants on both sides of the market seams must be treated in a "just and reasonable matter," Rothleder said.

"A seam isn't inherently a problem. It's simply a place where two systems meet," he said.

The shared goal of dealing with seams is straightforward. If a seam doesn't need to exist, let's avoid creating one, Rothleder said.

But when a seam is unavoidable — and it sometimes is — entities must focus on minimizing its impact. That means clarity in roles and responsibilities, transparencies in expectations and empathy in how to collaborate, he said.

It is important also to recognize that Eastern joint operating agreements are not plug-and-play solutions for the West, added Anna McKenna, vice president of market design and analysis at CAISO. In the East, these agreements are typically bilateral and encompass topics that in the West are addressed with standards, framework agreements and operating procedures, she said.

Overall, the town hall "showcases the progress the ISO has made to deliver reliability and economic benefits by coordinating and optimizing across the Western energy footprint," Rothleder said.

"If we keep approaching our work with the same level of honesty, shared purpose and adaptability, we will continue to operate as a community. I am looking forward to seeing what we have built, and what we will build next, together," Rothleder said. ■

Offshore Wind Group Questions CPUC's Proposed Forecast for Humboldt Project

Failed Federal Efforts to Derail East Coast Projects Should be Considered, Group Says

By David Krause

An offshore wind group has urged the California Public Utilities Commission to reject an internal proposal to use a forecast six-year delay to a Humboldt County offshore wind project to inform the state's grid planning.

Representatives of Offshore Wind California (OWC) said the Humboldt offshore wind project's online date in the forecast should be revised from 2041 to 2036, according to a Feb. 6 *filing* with the CPUC.

The forecast is part of a *proposed decision* on electric integrated resource planning and procurement by CPUC Administrative Law Judge Julie Fitch, which commissioners will vote on during their Feb. 26 meeting. (See *CPUC Portfolio Shows Offshore Wind Delayed up to 6 Years*.)

The projected six-year delay should be eliminated because offshore wind projects are moving ahead on the East Coast, despite Trump administration actions to attempt to hinder them, OWC said.

"Offshore wind is demonstrating its legal as well as business-case durability, even while under attack by the current administration," OWC said in the filing. "Planning assumptions that doubt offshore wind's ability to succeed do not reflect the prevailing legal reality. Nor do they capture the realities of steel in the water, which show eight projects are proceeding towards completion on the U.S. East Coast that will deliver more than 6 GW of clean power by 2027."

Transmission planning often occurs over decades: The CPUC should not delay making important infrastructure decisions to react to what are likely to be short-term federal policy headwinds, OWC added.

Humboldt Bay in Northern California | *County of Humboldt*

Why This Matters

The projected online dates for California's offshore wind projects affect transmission planning and use of existing transmission infrastructure, such as that connected to Diablo Canyon Power Plant, set to retire in the coming years.

California's offshore wind projects will not need federal permitting for several years, so the Humboldt project could be online in 2036, the same time as the Morro Bay offshore wind project along the state's central coast, OWC said.

The California Energy Commission (CEC) in October 2025 dished out $42 million for port upgrades to support the state's offshore wind projects. (See *CEC Approves 5 Offshore Wind Projects at California Ports*.)

A month later, the CEC approved $9.2 million for research on deepwater HVDC substations and ocean monitoring methods capable of detecting entangled debris. (See *'There's Room for Everybody': California Ports Prepare for OSW Development*.)

The CPUC should eliminate the limited wind sensitivity case in the commission's Jan. 14 proposed decision on the matter, OCW said. The group said the portfolio is "unreasonably conservative and unnecessary and directly conflicts" with California AB 525, which shows 25 GW of offshore wind generation by 2045, CAISO's $4.6 billion in transmission investments to support offshore wind and the $475 million approved to upgrade port infrastructure for offshore wind.

The CPUC included the limited wind case portfolio due to recent increased difficulty of permitting wind projects and federal policy changes toward the projects, the commission said in the proposed decision. ■

Prolonged Cold Drove Record Monthly Energy Costs in New England

By Jon Lamson

New England experienced record-high energy costs in January amid cold weather, high gas prices and heavy reliance on oil-fired generation, *according to* ISO-NE.

The energy market's value totaled about $2.7 billion in January, the highest monthly total in the region's history, the RTO told the NEPOOL Participants Committee on Feb. 5. The monthly costs surpassed the previous monthly record of nearly $2.2 billion in January 2014.

Much of the cost was concentrated during the extended stretch of cold weather at the end of the month. Temperatures averaged about 14 degrees Fahrenheit below normal over the last nine days of the month, ISO-NE noted. Energy market costs totaled $422 million on Jan. 27 alone, up nearly 150% over the previous daily total.

The grid experienced its highest peak load of the winter on Jan. 25 at 20,221 MW, exceeding ISO-NE's high-range forecast of 21,125 MW.

Gas prices also broke records: The maximum day-ahead gas price in Massachusetts reached about $122/MMBtu on Jan. 27, the highest maximum since ISO-NE launched its standard market design in 2003, easily exceeding the previous record of about $82/MMBtu.

ISO-NE CEO Vamsi Chadalavada praised the performance of the region's resource fleet throughout the cold stretch while acknowledging the region is not out of the woods yet, with more cold weather

Also at the Meeting

ISO-NE expressed support for a series of changes to the RTO's day-ahead ancillary services market proposed by the Internal Market Monitor, as well as an openness to changes to its Pay-for-Performance rate aimed at striking a balance between performance incentives and risk premiums in the capacity market.

Snow accumulation amid Winter Storm Fern in the Boston area | © *RTO Insider* forecast for the coming weekend.

Oil-fired generation, which typically accounts for less than 1% of energy in the region on an annual basis, provided 28% of energy from Jan. 24 through Feb. 1. Gas-fired generation also accounted for about 28% of energy, followed by nuclear at 19%, imports at 11%, renewables at 9% and hydropower at 5%.

On Jan. 25, ISO-NE obtained a waiver from the Department of Energy allowing generators to operate in excess of emissions limits, intended to enable resources to provide as much power as possible throughout this event. The RTO has received an extension of this waiver until Feb. 14.

With the waiver in place, about 21 resources have exceeded some limit at some point during the event, said Stephen George, vice president of system and market operations at ISO-NE.

The region burned about 66 million gallons of oil between Jan. 24 and Feb. 1, causing significant depletion of resources' stored fuel inventories, he said. Fuel oil inventories dropped from 43% of the region's total storage capacity to about 20%, according to data as of Feb. 4. This has caused the region's inventory of stored fuel oil to drop to its lowest point in the past 10 years.

Heavy snowfall across the region on Jan. 24 and 25 hindered generators' replenishment capabilities, he noted, adding that he expects to see a significant uptick in storage levels over the next couple weeks as oil consumption declines and generators continue to replenish their tanks.

He added that oil consumption by dual-fuel generators "contributed to a high demand for demineralized water trucks which were in short supply."

While snowfall significantly limited the output of solar resources, wind resources generally performed well, averaging about 885 MWh over the nine-day period.

Imports from neighboring regions averaged about 1,900 MWh during the period, with about 52% coming from Québec and 41% coming from New York. However, flows reversed over about a two-day period coinciding with the winter storm, with New England sending power to Québec amid tight conditions in the province. (See *Hydro-Québec Halted NECEC Deliveries amid Reliability Concerns*.)

George said these exports cleared in the day-ahead market and were not emergency exports.

ISO-NE also experienced by far its highest monthly costs in its new day-ahead ancillary services (DAAS) market, which the RTO launched in March. While some stakeholders had already expressed concerns about the high costs experienced in the new market, monthly per-megawatt prices roughly doubled in January relative to December levels.

The ISO-NE Internal Market Monitor estimates that DAAS costs totaled $921 million between March and January, dwarfing the RTO's projection of $140 million in annual costs.

In response to the spike in DAAS market prices, the Monitor *recommended* three "targeted market design adjustments," with the support of ISO-NE.

They include upwardly adjusting how it formulates the strike price "to better align it with the short-run marginal costs of resources providing these ancillary services"; decreasing the forecast energy requirement "to reflect the expected contribution of renewable generation"; and considering decreasing the non-performance factor in the 10- and 30-minute operating reserve requirements in the day-ahead and real-time markets.

Taken together, the changes "represent narrow but meaningful refinements" that should "enhance cost effectiveness while remaining aligned with the core objectives of the DAAS design," the Monitor wrote.

Also at the meeting, Chadalavada signaled an openness to considering changes to the region's Pay-for-Performance rate, emphasizing the need to strike the right balance between setting strong performance incentives for capacity resources and avoiding excessive risk premiums in future capacity auctions.

He stressed the importance of both moving with agility to address potential market issues and building consensus among stakeholders to ensure durable solutions. He said ISO-NE aims to implement the proposed DAAS changes in time for next winter.

Several stakeholders expressed support for this sentiment and applauded ISO-NE for its performance throughout the cold weather event and for being open to market changes in response to cost concerns. ■

Revolution Wind Weeks Away from Generating Power — Maybe

Embattled New England OSW Project Has Twice Staved off Stop-work Orders

By John Cropley

If Ørsted can continue to beat back the Trump administration's interference, it could start generating electricity with its Revolution Wind project in a matter of weeks.

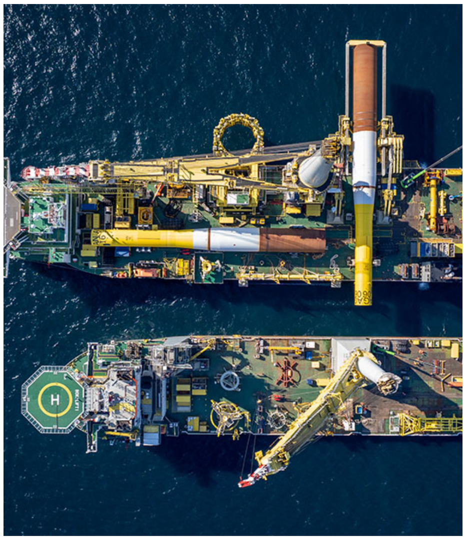
The 704-MW wind farm off the New England coast is 87% complete, with the export cables, interlink cable and both offshore substations energized, *CEO Rasmus Errboe said Feb. 6*.

The developer expects the facility to reach commercial operation and full power delivery to Connecticut and Rhode Island in the second half of 2026, barring further setbacks.

Errboe gave the update on Revolution and Ørsted's other North American project, Sunrise Wind, during a fourth-quarter and full-year *earnings presentation* to financial analysts.

The Trump administration shut down work on Revolution in August and then shut down work in December on Revolution, Sunrise and the three other wind farms under construction by other developers in U.S. waters on grounds of preserving national security.

Ørsted won injunctions against all three stop-work orders, but the shutdowns caused it to lose several weeks of work and take a $90 million impairment. And the injunctions are only temporary protection in the Trump administration's campaign against offshore wind.



Construction of Revolution Wind is shown in 2024. | *Revolution Wind*

Ørsted began running into problems with its U.S. offshore portfolio in the form of soaring costs and logistical constraints well before Donald Trump was elected to a second term and followed through on his campaign-trail rhetoric against offshore wind.

The Denmark-based offshore wind market leader already has indicated it would undertake no further projects in U.S. waters but an analyst nonetheless asked Errboe during the conference call if he would be "interested in increasing your exposure in the U.S. market at all."

He replied: "We have no expectations whatsoever to increase our exposure to offshore wind in the U.S."

Errboe said Ørsted decided shortly after he became CEO in January 2025 to concentrate on wrapping up the two U.S. projects and refocusing its offshore attention on its core European market, plus select Asia/Pacific markets. Value is the priority, not volume.

The company retains its undeveloped wind leases in U.S. waters but has no plans for them, he said.

However, Ørsted still is engaged in onshore U.S. renewables development, which it set up as a separate business unit in October 2025.

"The business is going well, we are moving forward projects, we have right now roughly 500 MW under construction — one wind project, 260 MW, in MISO, and one battery, 250 MW, in ERCOT," Errboe said.

"And then on top of that, we have 6 to 7 GW of capacity that meet the IRS qualifications through 2029, and we have this development portfolio consisting of mix of solar, wind and storage, slightly weighted more towards solar in the near term. So, moving forward well."

Why This Matters

ISO-NE has said Revolution will be important to reducing reliability risks, and NYISO has said Sunrise will help address the capacity shortfall identified in downstate zones.

Errboe said 59 of Revolution's 65 turbines are installed and work is approximately 87% complete on the project, a joint venture with Skyborn Renewables.

Sunrise Wind, which will send up to 924 MW to New York, is 45% complete with 44 of 84 foundations installed, onshore and near-shore export cables installed, and fabrication completed of most remaining components. First power is expected in the second half of 2026 and commissioning is expected in the second half of 2027.

Ørsted is developing Sunrise alone. After Eversource departed the project, Ørsted sought an equity partner, but the actions of the Trump administration spooked potential investors to the point that the conditions they set for joining the project were untenable, Ørsted has said. (See *Ørsted to Raise $9.3B, Self-finance Sunrise Wind*.)

It has said Revolution and Sunrise will have a combined cost of approximately $16 billion.

ISO-NE has said Revolution will be important to reducing reliability risks, and NYISO has said Sunrise will help address the capacity shortfall identified in downstate zones. (See *ISO-NE Warns Halting Revolution Wind Boosts Reliability Risk* and *NYISO Again Identifies Reliability Need for NYC*.)

Ørsted reported 2025 revenue of $11.6 billion, up from $11.2 billion in 2024; EBITDA of $3.6 billion, down from $5.1 billion; and net profit of $501 million, up from $2.5 million. ■

Conflict Brewing over Gas Transition in Massachusetts

By Jon Lamson

In Massachusetts, a state with some of the most ambitious decarbonization policies in the country, fundamental disagreements between utilities and consumer advocates threaten to derail the transition from natural gas before it even gets off the ground.

While technical in nature, these disagreements ultimately boil down to different visions of the role of the gas system — and the role of its utilities — in a decarbonized Massachusetts. With affordability already dominating energy politics throughout New England, the direction and effectiveness of the state's transition could have major implications on consumer costs for years to come.

The arguments over the future of the state's gas system are not new; many of the underlying disagreements date back to the Department of Public Utilities' multiyear and at-times-controversial investigation into whether to maintain the system while decarbonizing the fuel, or transition completely away from it altogether.

Initiated in 2020 under Gov. Charlie Baker (R) at the request of then-Attorney General Maura Healey (D), the investigation highlighted the major differences in the strategies proposed by the investor-owned gas utilities and climate and consumer advocates.

Throughout the proceeding, the utilities promoted a strategy reliant on alternative fuels and hybrid electrification. This proposed approach would keep much of the state's gas network in place to back up electrified heating while blending hydrogen and "renewable" natural gas (RNG) into the system to lower the carbon intensity of the fuel.

By contrast, climate advocates pushed for a full-electrification strategy. They argued that alternative fuels like RNG and hydrogen are expensive, scarce and ultimately non-viable for residential heating at a large scale, and that a hybrid electrification strategy would lead to excessive costs associated with building out the electric system while continuing to invest in the existing gas network.

Why This Matters

The fate of Massachusetts' gas transition could have major effects on decarbonization, consumer energy costs and the New England electric system. The region's grid is highly reliant on gas generation, and widespread heating electrification could drive up power demand while simultaneously freeing up pipeline capacity for generation.

The DPU concluded the investigation in late 2023 under new leadership appointed by Gov. Healey, who took office at the start of that year. While climate advocates had criticized the DPU under Baker for relying on utility-hired consultants to conduct the technical analysis for the investigation, the department ultimately agreed with the advocates on the core issues.

With the order, the department established a regulatory framework "to move the commonwealth beyond gas and toward its climate objectives." It expressed skepticism about the cost effectiveness of a "broad hybrid heating strategy" that maintained the bulk of the state's gas distribution system. The DPU also declined to allow utilities to recover costs associated with procuring alternative fuels, citing concerns about "costs, availability and the treatment of renewable fuels as carbon neutral."

The order required the utilities to file "climate compliance plans" plans every five years, evaluate non-pipeline alternatives when making gas system investments, cease promoting gas expansion with ratepayer funds and pursue targeted electrification pilot projects (*D.P.U. 20-80-B*). (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

But in the two years following the landmark order, the conflicts that defined the DPU's investigation have continued in the regulatory proceedings that have branched out from the ruling.

Across proceedings related to gas demand forecasting, pipe leaks, the climate compliance plans and the future of the region's only LNG import terminal, the utilities have butted heads with proponents of the transition.

The utilities have been slow to embrace gas alternatives and pipe decommissioning at scale, which their critics attribute to the companies' profit motive and reluctance to give up their traditional business model.

In contrast, the utilities have dug in on the language of customer choice, and they argue they lack the legal authority to decommission pipes without obtaining the consent of all affected customers. They argue that if a single customer on a pipeline segment is not willing to give up gas service, they cannot decommission the pipeline, even if electrified alternatives are available.

While advocates dispute this reading of state law, the question about the utilities' authority to retire parts of the gas system remains unsettled, as does the underlying question of whether the state will ever be able to get its investor-owned utilities to embrace a transition away from gas.

The Obligation to Serve

According to the state's gas distribution companies, their obligation to provide gas to existing customers stems from their franchise rights as regulated utilities.

"In exchange for a monopoly franchise, LDCs [local distribution companies] must actually provide natural gas service to customers absent the legislature rescinding their franchise charter or other clear legislative action alleviating the obligation to serve customers residing in a franchise territory," the companies wrote in a joint filing in October in response to an inquiry by the department (*D.P.U. 25-40, et al.*).

In contrast, climate and consumer advocates argue the utilities' obligation to serve does not prohibit the companies from substituting gas service for alternatives — such as networked geothermal or other electrified heating technologies — when viable alternatives are available. They point to a 2024 *change in state law*, which, according to its the lead senator in the negotiations, amended the obligation to serve to prevent issues related to holdout customers. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

The 2024 law directed the DPU to consider the public interest and the availability of non-gas alternatives for heating and cooking when ruling on petitions for gas service. It also explicitly authorized the department to "order actions that may vary the uniformity of the availability of natural gas service."

The utilities argue that this change in law changed neither the "the legal foundation for the obligation to serve existing customers" nor the "obligations of the LDCs to existing customers."

The Massachusetts Attorney General's Office, the official ratepayer advocate in the state, disagrees. It argued in response that the DPU is well within its authority to authorize the disconnection of gas customers to advance the public interest.

With the 2024 changes to state law, "the legislature aligned the obligation to serve with the commonwealth's climate goals by expanding the power of the department and articulating a balancing test to weigh the interests of the commonwealth with the interests of the individual customer," the AGO wrote.

"It is illogical to suggest that the LDCs and department lack the authority to deny or discontinue gas service to promote the public interest in cost-effective decarbonization," it added.

The DPU has yet to rule on the question of the utilities' obligation to serve, and its interpretation of state law could face legal challenges from the utilities if the department ultimately sides with the consumer advocates. The potential impacts are substantial.

"It's a very important issue," said Jamie Van Nostrand, who led the DPU from 2023 through fall 2025 and oversaw the department's order on the gas decarbonization investigation. He is now policy

National Grid

director for the Future of Heat Initiative. (See *Outgoing Mass. DPU Chair Van Nostrand Discusses Gas Transition*.)

Under the utility interpretation of the statute, "it's all about customer choice, and if the customer wants to keep their gas, end of discussion — no decommissioning," he said. "That is a bad outcome, because we need to have a managed transition."

Stranded Assets

A managed transition, Van Nostrand said, is essential for long-term energy affordability in the state. Since leaving the DPU in the fall, he has been vocal in the ongoing affordability debates in the state, raising the alarm about the trend of increased spending on gas infrastructure.

According to an *analysis* by the Future of Heat Initiative, gas utilities in the state more than doubled their assets between 2014 and 2024, significantly increasing customer costs despite a 22% decline in per-customer gas demand.

"If you can't shrink the system as the throughput goes down, delivery charges go through the roof; it's simple math," Van Nostrand said.

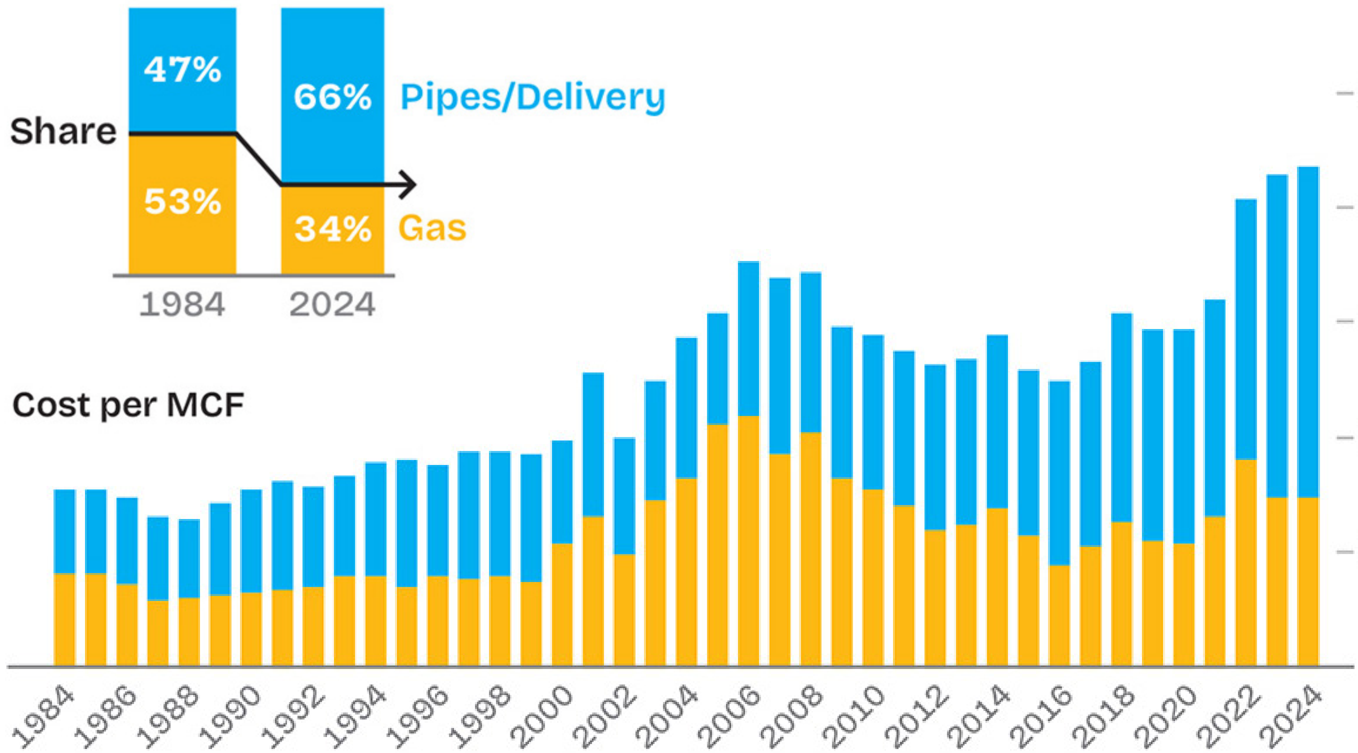
A large portion of this spending has occurred under a state program that gives the gas companies expedited cost recovery for replacements of leak-prone pipes. The costs of the Gas System Enhancement Plan (GSEP) program have risen rapidly in recent years, totaling $814.4 million in 2024. In total, the utilities spent more than $4.7 billion through the program between 2015 and 2024.

In an attempt to rein in the spending, the state has made several amendments to the GSEP *statute* in recent years to increase emphasis on pipe relining and repair, along with non-pipe alternatives, including networked geothermal.

But despite the efforts to curb spending and prevent stranded assets, costs have continued to rise, and traditional pipe replacements continue to constitute essentially all GSEP projects.

According to the utilities, the rise in GSEP costs is the result of the effects of inflation and supply chain constraints on the prices of materials and labor. In a written response to questions, Eversource Energy, one of the two major gas utility companies in the state, wrote that it already has replaced the bulk of the most accessible pipes and that its remaining portions of leak-prone pipes tend to require more complicated and expensive construction.

The company said an increased focus on pipeline repair would not help limit costs, writing that "there is no viable method for 'repairing' leak-prone infrastructure



Residential gas delivery charges and supply costs in Massachusetts, 1984-2024 | *Future of Heat Initiative*

in a manner that obviates the need for replacement or that achieves the level of public safety that is achieved through replacement."

"Prioritizing repairs over replacement can lead to higher longer-term costs, as sections of leak-prone pipes will likely require multiple future repairs and ultimately be replaced anyway, at which point the cost of replacement will have likely increased," it added.

Van Nostrand did not dispute the underlying economic conditions, but he did highlight the attractive financial proposition to the utilities of expedited cost recovery, as well as the regulatory incentive structure that enables the utilities to earn more money from capital investments than from operating expenditures.

"Utilities are going to respond to whatever mechanism the regulators put in front of them," he said. "They have a fiduciary obligation to shareholders to maximize profits, and that's what they're going to do.

"It's great for shareholders to replace [pipes]; it's bad for ratepayers. If your state has an aggressive greenhouse gas target like Massachusetts does — net zero by 2050 — putting a pipe in the ground that's going to last 50, 60 [or] 70 years does not make any sense."

He said expedited cost recovery on the GSEP investments has removed the important check on utility spending that regulatory lag provides in traditional ratemaking. This lag between when utilities increase their spending and when rates go up "provides a strong incentive for the utility to control costs," he said.

In April, the DPU lowered the cap on GSEP spending from 3 to 2.5% of total firm service revenues and indicated it will likely cut the cap to 2% in 2026 and 1.5% in 2027. The cap reduction, coupled with a ban on carrying charges, is intended to limit the amount of spending for which the utilities can receive expedited cost recovery. (See *Mass. DPU Aims to Align Gas Leak Program with Climate Strategy*.)

While questions about the obligation to serve could inhibit the use of non-pipe alternatives instead of traditional pipe replacements, "the vast majority of these projects aren't even getting to that point of having conversations beyond just the internal utility screening," said Jeremy Koo, assistant director of clean energy at the Metropolitan Area Planning Council, a regional planning agency representing municipalities in the Boston area.

He said there is "definitely a lack of transparency" around why utilities have ruled out repairs and non-pipe alternatives for GSEP projects.

"We're really concerned about it from the perspective of stranded assets," he said, noting that the utilities' approach appears to entail increasing levels of investment in both the gas and electric systems, with ratepayers left with the costs.

He added that he is similarly concerned that lower-income customers who lack the means to exit the gas system will become saddled with an increasing share of the gas system's growing fixed costs.

Separate but Related

The utilities' increasing investments in pipe replacement bears more than a few similarities to growth of asset condition costs on New England's electric transmission system.

Asset condition spending, which is aimed at upgrading deteriorating transmission infrastructure, has cost the region $4.67 billion for projects placed in service since the start of 2020, according to an October update from the region's transmission owners.

Eversource and National Grid, which own the largest gas utility businesses in Massachusetts and two of the three largest electric transmission footprints in the region, are responsible for the vast majority — $4.2 billion — of asset condition spending since 2020. Asset condition investments are subject to limited regulatory scrutiny, passing to ratepayers through FERC formula rates.

Concerns about the spending have caused the New England states to make a big push for increased oversight and transparency into the projects over the past several years, and ISO-NE is establishing internal asset condition review capabilities that could provide information for potential challenges of the spending with FERC.

But at a recent event held by the Northeast Energy and Commerce Association, Rhode Island Public Utilities Commission Chair Ron Gerwatowski said this might not be enough. He said the states may need to consider changing how transmission costs are recovered through electric rates.

To reduce the TOs' appetite for spending, he said, the states could introduce regulatory lag by requiring them to recover costs through the full base rate case process, instead of as pass-through costs.

Echoing Van Nostrand's comments on gas pipe replacement spending, Gerwatowski said subjecting asset condition spending to regulatory lag "could give the financial folks an incentive to push back" on the investments. (See *Facing Rising Demand, New England has Limited Options for New Supply*.)

'A Very Expensive Insurance Policy'

As regulators eye a managed transition away from gas, the future of the Everett Marine Terminal (EMT), an LNG import facility just north of Boston, remains a multimillion-dollar question mark. Similar to the GSEP program, questions about the gas utilities' obligation to serve could have a major bearing on the terminal's future.

The LNG facility is on the site of the Mystic Generating Station, a retired gas-fired power plant that was once its primary customer. The plant retired in 2024 at the end of a two-year reliability-must-run agreement with ISO-NE.

To keep the EMT in operation following the closure of Mystic, the Massachusetts gas utilities signed contracts with Constellation Energy, the owner of the facility, to keep the terminal open into 2030. (See *Massachusetts DPU Approves Everett LNG Contracts*.)

In the DPU's approval of the contracts, it acknowledged the importance of the facility to ensure the reliability of the region's gas system during peak days, but it directed the gas distribution companies to take action to reduce their reliance on the facility.

The EMT is located at a strategic location at the heart of the state's gas system, has access to both the Tennessee and Algonquin pipeline systems, and can feed directly into National Grid's distribution network.

"That was a tough decision," Van Nostrand said. "Basically, it's a very expensive insurance policy."

Brattle Group consultants hired by the AGO estimated during the proceedings that the EMT contracts would cost a combined $946 million over their six-year span. (See *Everett LNG Contracts Face Skepticism in DPU Proceedings*.)

Gas customers in the state could face significant additional costs once the contracts expire if the utilities can't eliminate their reliance on the facility.

Despite the regulatory requirements and a state-led working group focused on eliminating the state's reliance on the facility, "another round of contracts seems incredibly likely," said Carrie Katan, policy advocate at the Green Energy Consumers Alliance.

Katan, a member of the state's Everett working group, said, "At this point, it does not look like either NSTAR [one of Eversource's two gas distribution service territories] or National Grid are going to be able to basically function without EMT post-2030."

A proposed expansion of the Algonquin pipeline system may cut some of Eversource's reliance on Everett. The company's recently approved firm transportation agreements associated with the expansion project would eliminate the need to extend the Everett contract for one of its service territories and partly eliminate the reliance on the terminal for its other service territory, Eversource wrote (*DPU 25-133, 25-134*).

But eliminating reliance on the terminal in one service territory could result in shifting the facility's significant fixed costs onto gas customers in other areas still reliant on it.

It is also unclear what Constellation might charge to keep it open past 2030.

"Constellation is not operating on any kind of cost-of-service agreement: They can charge whatever price they want, and if they wanted to shut down EMT whenever they decided to, they could do that," Katan said.

Van Nostrand concurred: "The LDCs put themselves in a position where they're pretty much at Constellation's mercy."

Katan said National Grid appears to be in the "weakest negotiating position," adding that "it really does seem to me that [Constellation] could decide to squeeze National Grid as hard as possible, and I don't know of anything National Grid can do."

National Grid declined to comment on whether it expects to seek additional contracts with Constellation. It said in a statement that its "responsibility is to operate a safe, reliable gas system for the customers who count on us, which requires making the investments necessary to keep aging infrastructure secure."

Eliminating reliance on the Everett facility would require "a number of interventions, which would take a large amount of time," such as strategic electrification or a moratorium on new gas hookups in EMT-constrained areas, Katan said.

But the utilities' insistence that they cannot decommission lines without the consent of all customers complicates the picture.

While neighborhood-wide networked geothermal heating systems had drawn significant attention in the state in recent years, including pilot projects run by Eversource and National Grid, "if you want to deploy networked geothermal on a large scale outside of the pilots, you're going to have to decommission the gas lines," Katan said.

If the state cannot decommission pipes, "I don't think we have anything when it comes to controlling gas costs," she said. "I think at that point you would just need to accept that the situation is bad, it will get worse, and there is absolutely nothing that can be done about it." ■

MISO States Dispute 'High Risk' Designation from NERC

By Amanda Durish Cook

Members of the Organization of MISO States have sent a letter to contradict aspects of NERC's Long-Term Reliability Assessment, disputing the ERO's label of MISO as being at "high risk."

State regulators in MISO said NERC should have counted resources in MISO's fast-track interconnection queue in assessment totals.

MISO was branded high risk in the near term by NERC in its *2025 LTRA*, along with PJM, ERCOT and northern portions of WECC. (See *NERC Warns of 'Worsening' Resource Adequacy Through 2035*.)

Organization of MISO States President Michael Carrigan, of the Illinois Commerce Commission, sent the letter to NERC CEO James Robb on behalf of "several" other OMS member states concerned about MISO's designation in the LTRA. The letter was not considered a statement from the OMS Board of Directors.

Carrigan wrote that MISO's generator express lane — "developed collaboratively by state regulators, MISO and stakeholders" — is well underway, "and it is expected to address emerging capacity needs in the near to medium term."

MISO has more than 11 GW of natural gas generation and battery storage proposals in the first two cycles of its expedited interconnection queue that are set to come online by mid-2028. The grid operator will accept more projects throughout 2026. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

At a Feb. 4 MISO Advisory Committee meeting, OMS Executive Director Tricia DeBleeckere said OMS members aired concerns "most importantly because the report did not include" projects in the queue fast lane. She said the expedited generation should neutralize the 7-GW shortfall NERC expects to materialize in winter 2028.

NERC has acknowledged its model didn't include MISO's expedited generation proposals. It said if the projects arrive as promised, a projected reserve margin shortfall "would be eliminated." MISO expects about 8.6 GW more of winter on-peak capacity to reach operation by 2028/29 through the expedited queue.

Per NERC's assessment, MISO is due to experience a net loss in natural gas units by 2030. MISO's queue fast lane is comprised mostly of natural gas-fired additions.

'Red' Again

OMS continued to voice dissatisfaction with NERC conclusions at a Feb. 6 meeting dedicated to resource adequacy.

"MISO continues to be red. But we think there's a lot of work in the region … that's changing the trajectory," DeBleeckere said.

She said MISO and members "have concerns over the outputs" and that OMS representatives have been in communication with NERC officials since the release of the assessment.

DeBleeckere said there's a difference between MISO and members carefully crunching reserve margins and "heading toward a stop sign that we're not going to stop at."

She said she understands NERC must impose a cutoff on its data to begin working on the assessment.

"But this was such a big piece for us," she said of MISO's formation of the interconnection fast lane.

NERC's inclusion of a sidebar in the report indicates NERC realizes the generator fast lane will mitigate risk, DeBleeckere added. She said MISO's largely vertically integrated utility model would not allow "massive amounts of load that is unresourced."

> **The Bottom Line**
>
> State regulatory agencies are challenging NERC's Long-Term Reliability Assessment, which rated MISO as "high risk." They say NERC treats planned retirements and load additions as certainties, while replacement generation is branded as uncertain.

OMS is meeting with MISO and NERC representatives to understand "the math that goes into the models that produce these results," DeBleeckere said. She said NERC's perceived risk of a shortfall by winter 2028/29 clashes with MISO's summer-peaking conclusions from loss of load studies and that NERC's interpretation might be one of an array that could be drawn.

DeBleeckere said there may be a "translation issue" between the way utilities plan their resources and how NERC draws its conclusions.

OMS believes there could be issues with the reference margin levels NERC uses in the LTRA, which assume risk only in summertime. NERC's winter reference margin levels use a one-event-in-100-years assumption.

MISO uses varying seasonal requirements to account for risks. For the 2026/27 planning year, MISO found a slight loss of load risk in all winter months, leading it to use a 0.014 days/year risk — roughly equivalent to one day in more than 70 years — in its loss of load expectation *study*.

Interestingly, NERC determined MISO would maintain resource sufficiency in summers through 2029, even with an added 10 GW of load growth and a peak demand drifting upward to 138 GW.

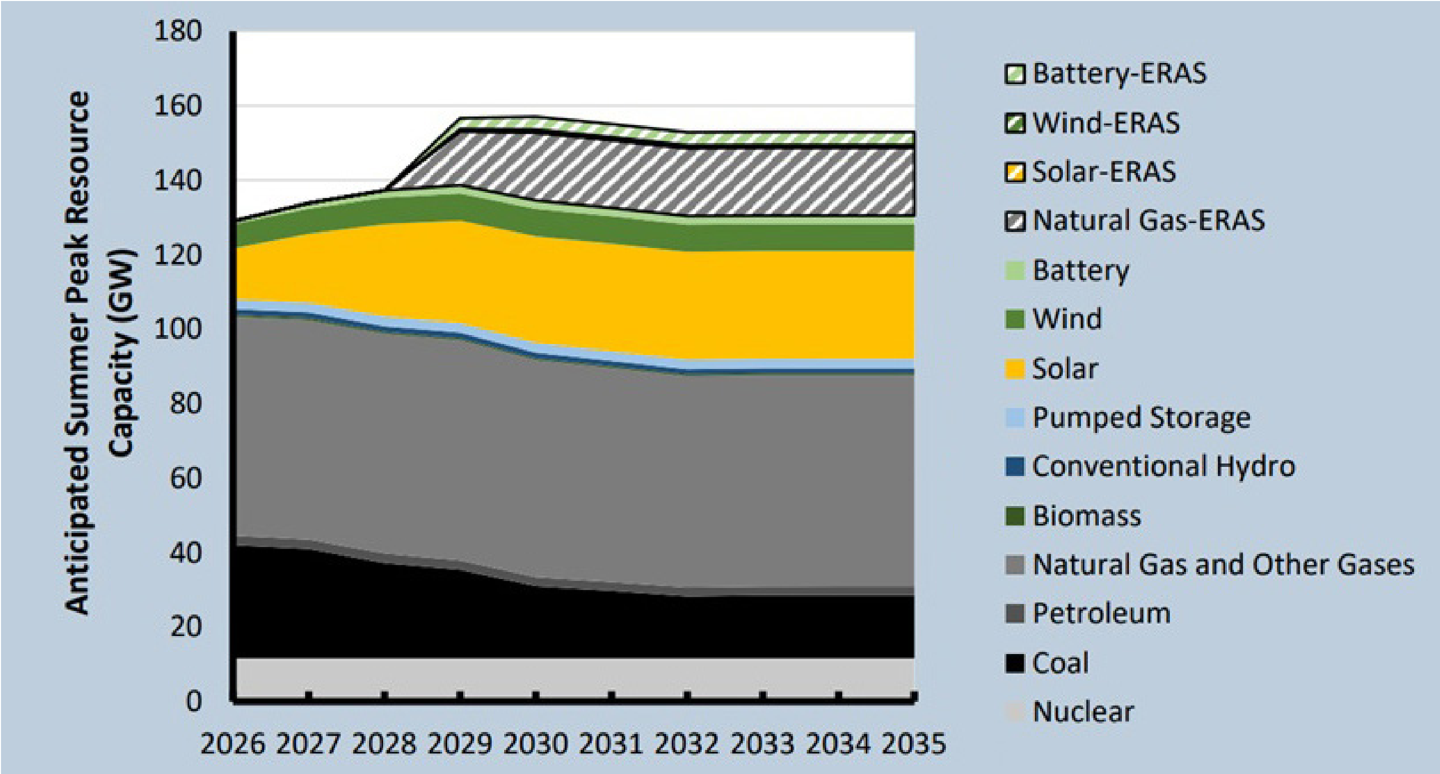
Wisconsin Public Service Commissioner Marcus Hawkins said he wanted MISO, members and regulators to focus on the anticipated summertime performance.

"That is wildly impressive in this assessment, so I don't want this to get lost among the concerns," Hawkins said.

Bill Booth, a consultant to the Mississippi Public Service Commission, asked how results would be used and which outcomes they could influence.

DeBleeckere said beyond the report "hitting hard" in the press, the U.S. Department of Energy has used NERC assessments to justify keeping generation online in emergency 202(c) orders.

"It also can certainly work its way into state dockets," Hawkins added.



Potential expedited resource additions in MISO beginning in 2027, according to NERC's LTRA | *NERC*

Booth predicted reacting to the report would involve "damage control."

'Already Proactively Addressed'

Meanwhile, Carrigan noted in his letter that most utilities in MISO and state commissions coordinate to anticipate demand growth, retire generation and plan new generation through integrated planning approvals. He said reliability is handled "holistically" in MISO.

"[S]tate regulators, regulated utilities and MISO are actively engaged in identifying and mitigating evolving risks and have well-established tools to do so, as we have been doing for decades. Many risks highlighted in the assessment have already been proactively addressed in the MISO region, for example, by establishment of winter planning requirements," Carrigan wrote.

Carrigan added that NERC treats planned retirements and load additions as certainties, while replacement generation is branded uncertain until the projects traverse regulatory, interconnection or market prerequisites.

"Utilities and regulators are aware of evolving system needs and have been, and will continue to be, actively engaged in taking corrective planning and regulatory actions to maintain reliability," Carrigan wrote.

Carrigan said OMS' well-established resource adequacy survey in conjunction with MISO often predicts shortfalls years down the road, similar to the LTRA. But he said the OMS-MISO survey's "out-year uncertainty is a structural feature of planning-based jurisdictions and is routinely managed through coordinated utility planning, regulatory oversight and market and policy actions, well before reliability could be affected."

Carrigan recommended NERC incorporate MISO's longstanding planning processes and work from its collection of jurisdictions to moderate LTRA results. He said more balanced results could help dodge "disproportionate economic or policy consequences driven by out-year risk signals."

"In MISO, the balance of state regulatory oversight, utility obligations and market mechanisms is intentionally designed to moderate risk and ensure timely corrective action," Carrigan wrote.

Southern Renewable Energy Association Executive Director Simon Mahan said NERC's "maps of doom" aren't helpful and that MISO's results in the assessment are "head-scratching." Mahan said NERC's inputs are outdated by the time it publishes the report, evidenced by the missing expedited resource additions.

"These maps are already being teed up in legislative hearings, regulatory filings and media articles as justification for: bypassing competitive procurement; fast-tracking utility self-build projects; locking in long-lived fossil investments; and sidelining lower-cost clean energy resources," Mahan *wrote* in a reaction piece, adding that knock-on effects include rising gas prices and less-thought-out reliability.

"People make decisions based on NERC reports, even if NERC attempts to dissuade just that," Mahan said.

In 2025, the MISO community similarly found itself at odds over NERC's risk interpretation in its LTRA. In that case, MISO's Independent Market Monitor criticized NERC's conclusion and pointed out an error.

NERC had used unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. After a back and forth between MISO and NERC, the reliability corporation ultimately downgraded MISO from "high risk" to "elevated risk." (See *IMM: NERC Reliability Assessment Still Overstating MISO Risk*.) ■

MISO Members Push for Modernized Storage Rules

Flexible 'Swiss Army Knife' Poised for Key Role in Future

By Amanda Durish Cook

MISO membership has called for modernized market rules for energy storage that can capture its chameleon-like roles.

This time, members at a Feb. 4 Advisory Committee teleconference suggested conversation starters to begin drafting rule changes.

Clean Grid Alliance Executive Director Beth Soholt said there are more uses for storage "than MISO is currently acknowledging or has rules to implement."

"Storage is very much posed to make an impact in MISO and help with the challenges MISO sees coming," Soholt said.


AES Indiana

Multiple members agreed storage is at once a market resource, transmission asset, load when necessary or a microgrid component and that rules should reflect those capabilities.

South Dakota Public Utilities Commissioner Chris Nelson said he agreed storage is the "Swiss Army knife" of the grid. But he added that commissioners must conclude that storage solutions are cost effective before approving them.

"Bottom line, that's what we're looking at," Nelson said.

However, Fresh Energy's Mike Schowalter said for storage to be cost effective, MISO's rules need to be flexible enough for storage to switch duties.

"We hear that it's a Swiss Army knife, but if it's not valued in the market for these things, then it's not going to benefit ratepayers," Iowa Utilities Commissioner Sarah Martz said.

"MISO's rules are not compatible for merchant services," Pelican Power's Tia Elliott added.

Elliott pointed out that MISO is the only RTO that requires storage to secure and pay for transmission service to charge from the grid, regardless of whether the charging is done under MISO dispatch.

Elliott said storage can interconnect quickly without placing reliability at risk and could help with large load integration. She suggested MISO members meet to discuss where they agree on the resource's monetizable capabilities.

Why This Matters

MISO members say the RTO cannot afford to wait much longer to introduce a set of multifaceted rules that allow electric storage to provide the various services it's capable of.

Schowalter said MISO could start by listing what storage is able to do that typical resources cannot.

"Storage can respond in 16 milliseconds — very fast," he said.

Schowalter said MISO's pricing framework and tools were designed long enough ago that MISO and members should examine what's outdated.

"Especially, as we add more renewables, storage is going to play a key role," he said, encouraging MISO members to imagine the system and what it would need in 2045 with majority renewable penetration.

"We really can't wait for that to happen to see what happens and the rules we'll need in place," Schowalter said.

"We can do it; we just have to find the will," Soholt said. ■

PSC Staff: We Energies' Data Center Rate Plan Lacks Consumer Safeguards

By Amanda Durish Cook

The Bottom Line

Chief among the Wisconsin PSC staff's concerns with We Energies' proposed data center rates: a 25% generation cost allocation to regular customers and a 10-year contract term for the large loads.

Analysts with the Public Service Commission of Wisconsin said ratepayers are at risk of subsidizing data centers if We Energies' proposed rate framework for data centers is given the go-ahead as proposed.

We Energies in late 2025 proposed a framework for customers requiring 500 MW or more to subscribe to dedicated resources, poised to be mostly natural gas at this point.

The utility proposed two types of electricity subscriptions for very large customers: The first would allow data centers to take all of a resource's output provided they cover all costs associated with the resource; the second would allow data centers to count a resource toward their capacity needs. In the second case, data centers would foot the bill on 75% of the specified resource's fixed costs; other customers would cover the remaining 25% plus all fuel costs. We Energies theorized that MISO market revenues would be enough to offset the expenses allocated to other customers (*6630-TE-113*).

Data centers that enroll would be bound to an initial, minimum 10-year contract, renewed thereafter in one-year increments. The rate styles contain early termination provisions where data centers could be billed for unrecovered capital costs if the resources don't find other customers.

Staff with the commission flagged consumer protection weak spots in We Energies' filing in late January. They said without stronger protection, utility customers could financially support data centers' grid needs. They said the 75/25 allocation and 10-year contract term were cause for concern.

Andrew Field, a utility auditor with the commission, said We Energies didn't capture the full range of market price volatility in its assumption that its other customers wouldn't underwrite data centers. In testimony, he said We Energies didn't "provide much detail supporting the specific future scenarios, or potential alternatives, upon which the provided analyses are based."

Field said We Energies' own analyses show the potential for costs to exceed benefits for the general rate base.

Even with the hopeful scenarios in its analyses, Field said We Energies found a net benefit for non-participating customers in only 67% of cases that include We Energies' pending Foundry Ridge turbine project and 81% of the cases that include its planned Red Oak Ridge turbine project.

Tyler Meulemans, a utility financial analyst with the PSC, said he harbors concerns with the 10-year term, including a data center's "ramp-up period," when projected load isn't fully realized. He said including the ramp-up period raises concerns over whether the agreement length is "sufficient to cover the costs incurred to provide service" to a massive data center.

Meulemans said when PSC staff requested a demonstration of revenue recovery would look like during a ramp-up period, We Energies' analysis showed that a 10-year term "would not cover all costs."

Two data center projects in We Energies' territory — Microsoft's AI data center campus in Mount Pleasant, Wis., and the Vantage/Oracle/OpenAI facility in Port Washington, Wis. — are to double We Energies' load by 2030. We Energies' investor *presentations* show the utility is prepared to spend $19.3 billion on new generation through 2029. The increase of more than $6 billion is due to increasing data center demand.

The Citizens Utility Board of Wisconsin and Power Forward Wisconsin, the latter of which is composed of clean energy groups, oppose the 75/25 allocation and have called on the PSC to make sure data centers pay for all the costs they cause.

Sierra Club's Jeremy Fisher was critical of the utilities' proposed rates and said they relied on assumptions that are too rosy.

Fisher said the rate structures "appear to have been negotiated and designed with the company's new data center customers, Microsoft and Vantage/Oracle," and rely on the assumptions that immense data centers will become profitable and future customers would have massive electricity needs and the means to finance them.

Fisher asked what happens if the AI boom fizzles.

We Energies "may look at these customers as an enormous opportunity to increase its rate base and expand operations, but the purpose of the tariffs must not only be to provide for reasonable allocation under optimistic conditions but ensure that incumbent ratepayers are protected under adverse scenarios," Fisher said in testimony to the PSC.

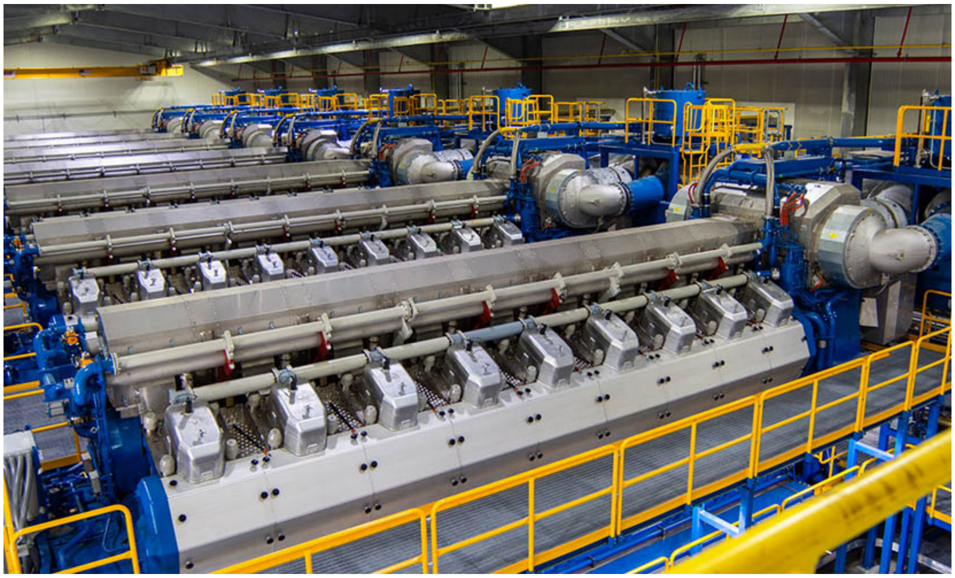
Fisher also said the rates would lead to an "inconsistent and balkanized planning process that should be deeply concerning to regulators in assessing actual resource requirements."

Richard Stasik, vice president of regulatory affairs of We Energies' parent company, said PSC staff and interest groups ignored We Energies' statutory obligation to serve all customers. He said the Sierra Club didn't quantify risks wrought by data centers and didn't acknowledge that the situation would be riskier without a dedicated rate schedule.

Stasik said We Energies existing customers would pay at least $1.5 billion in additional capital investments if large customers were to take service under the utility's existing rate designs. ■

States Consider Tapping MISO for Analyses in Path to Potential New RA Standard

By Amanda Durish Cook



Wisconsin Public Service Corp.'s Weston RICE units | *WEC Energy Group*

MISO state regulators are considering asking the RTO to keep tabs on resource adequacy risk indicators as they contemplate crafting a replacement standard in the footprint.

During a Feb. 6 meeting dedicated to the topic, members of the Organization of MISO States (OMS) were clear they should preside over development of a possible new resource adequacy standard in the RTO. They proposed that MISO's ongoing RA analysis could become a regular occurrence and help regulators decide when to substitute other benchmarks for the one-day-in-10-years loss-of-load standard.

MISO toyed with the idea of replacing or modifying the one-in-10 standard that its loss-of-load expectation study relies on. The grid operator suggested using conditional value at risk, loss-of-load hours or expected unserved energy as possible new measures of risk but has said it is not attached to any approach and is open to other ideas. (See *MISO Dips Toes into Potential New Resource Adequacy Standard; States Demand Key Role*.)

The RTO paused its formal work on a revised metric in 2025. Wisconsin Public Service Commissioner Marcus Hawkins said OMS expressed a desire for MISO to "tap the brakes and understand the topic more" before drawing up hypotheticals on different standards. He told fellow regulators that MISO is "waiting on us to steer the ship on this one."

Hawkins said it is time to communicate to MISO what regulators might want to explore and "establish guardrails" that respect state jurisdiction over resource planning.

"There's a potential if you change the resource adequacy metrics, that you change the requirements," Hawkins said. "Because we encouraged MISO to pump the brakes … it's now the time to collect our thoughts in a coherent way."

MISO is currently working on gap analysis, which seeks to capture risks that the existing loss-of-load metric might be missing. OMS expects to review the RTO's analysis later in 2026.

Over time, MISO expects risk to dwindle until it barely registers in the summer months, while winter mornings present challenges.

Werner Roth, economist with the Public Utility Commission of Texas, said OMS members need to examine what the gap analysis shows "five [to] 10 years from now."

"Do we start to see a deviation as the resource mix changes?" he asked rhetorically.

He said state regulators must have the last word on which resource adequacy standard MISO pursues. "We need to have the ultimate say in that. Anything less would be unacceptable."

Hawkins said OMS could direct MISO to continue tracking resource adequacy metrics from its footprint-wide vantage point so regulators know when they should change course on standards. The RTO would need to "produce a predictable source of information" that could potentially help regulators see risks that have not previously been obvious. He added that MISO would be creating probabilistic, forward-looking studies and said inputs into those studies should be well understood among regulators so there is no distrust and "we can have faith in the results."

Bill Booth, a consultant to the Mississippi Public Service Commission, asked if OMS should secure a third-party consultant to serve as a check on MISO's analysis results.

Hawkins said OMS could entertain the idea and that it has been in consultation with and gathering expertise from the National Laboratories. Representatives from some of the labs will appear at the organization's Resource Adequacy Summit in May, he said.

"We sort of got a line of sight on some of those experts," Hawkins said.

Hawkins also said OMS will be privy to other expert views because a new RA standard would be vetted through MISO's Resource Adequacy Subcommittee. He said OMS members would benefit from the larger stakeholder community's views. ■

The Takeaway

State regulators in MISO are still weighing approaches to potentially replace the one-day-in-10-years standard the RTO uses to gauge resource adequacy.

Data Center Moratorium Bill Introduced in N.Y. Legislature

By Vincent Gabrielle

| Shutterstock

ALBANY — Democrats in the New York Legislature have introduced *a bill* that would institute a three-year moratorium on the siting and permitting of new data centers statewide.

"Let's take a pause. We don't even understand all the implications this can have for the climate, environment, energy costs and water for the state of New York," said state Sen. Liz Krueger. Proposed data centers in the NYISO interconnection *queue*, she added, already represent 9.5 GW of load.

The legislators argue the pace of data center development has outstripped the existing planning, regulatory and environmental review frameworks. They say data centers are driving up the cost of electricity, creating more demand for fossil fuels and delaying New York state's climate goals.

"The fact is that we should not allow individual companies to skyrocket ahead with their plans that will cost us huge amounts of money, cost us huge amounts of environmental impact and cost us lost opportunities to make other decisions with our future energy planning," Krueger said.

Data centers are a hot topic across the country and make up the bulk of system impact studies discussed and approved by the NYISO transmission planning committee.

The new bill echoes New York's cryptocurrency mine moratorium. (See *NY Slaps Moratorium on Certain Crypto Mining Permits*.) Gov. Kathy Hochul signed that moratorium into law in 2022. The Hochul administration, however, recently reached an air rights settlement with Greenidge Generation Holdings, allowing the cryptocurrency mine to operate a gas generator in *Dresden, N.Y*.

Why This Matters

Data centers of all kinds account for a large percentage of New York's load growth over the next decade. A moratorium on new construction could impact short-term reliability, electricity prices.

The chances of passing a data center moratorium are unclear. Krueger and Assemblymember Anna Kelles introduced the bill, which is co-sponsored by Sens. Kristen Gonzalez, Rachel May and Lea Webb. The Democratic legislators are backed by a coalition of environmental and consumer advocacy groups, including *Food and Water Watch*, the *Alliance for a Green Economy* and the *New York Public Interest Research Group*.

"The proliferation of data centers and their insatiable appetite for ratepayer subsidies, excessive water use, noise pollution and regulatory secrecy must stop," said Blair Horner, senior policy adviser for NYPIRG. "New York state can show the nation how to regulate data centers in a way that protects consumers' wallets, the public's hearing and the environment's most precious resource: water."

The legislators and advocacy groups represent areas from New York City to rural Upstate. The *New York City Democratic Socialists of America*, fresh from their recent victory in the *NYC mayoral election*, also support the legislation.

The bill calls for the Department of Environmental Conservation to complete a comprehensive environmental impact statement on data centers, including the current and forecast effects on energy use, electricity rates, water resources, air quality and greenhouse gases. The Department of Public Service would be required to report the cost impacts of data centers on all other ratepayers and issue any new orders necessary to ensure those costs are paid by data center companies and developers.

"I want to emphasize the fact that this is simply a pragmatic decision to put a pause … and create commonsense regulations," Kelles said. "This industry has exploded very quickly, and we have not had the opportunity to create infrastructure in the government, both in law and regulations to ensure that … the industry does not have a significant negative impact on workers and our environment."

The bill would not block projects retroactively. It would pause new permitting by any government body, agency or public benefit corporation for construction, siting or the start of operations. Projects that already have permits would be allowed to continue.

The bill is awaiting discussion at the Senate Environmental Conservation Committee. ■

N.Y. PSC Changes DER Interconnection Rules to Meet Tax Credit Deadlines

By Vincent Gabrielle

The New York Public Service Commission has issued new interconnection rules for distributed energy resource developers and utilities aimed at capturing as many expiring Inflation Reduction Act tax credits as possible for wind, solar and storage projects (*24-E-0621*).

Issued Jan. 22, the rules require utilities to develop schedules and plans for completing the utility-side work to interconnect DERs seeking tax credits.

The One Big Beautiful Bill Act, signed into law on July 4, 2025, terminated the IRA's tax credits for wind and solar facilities going into service after Dec. 31, 2027. Under orders from President Donald Trump, the IRS *established* a deadline of July 5, 2026, for projects to have begun construction to qualify for the credits.

The IRS defined having "commenced construction" as developers having begun the physical work (whether on- or off-site) and having a continuous construction schedule. For small solar projects (1.5 MW and below), spending 5% of the cost of the project by the deadline satisfies the requirement. The IRS allowed for a four-year "safe harbor" allowance for construction delays outside the developer's control, like natural disasters or work stoppages.

The PSC divided DER projects into two groups based on whether the project requires utility-side system upgrades. For those that do, the commission gave utilities some discretion in how they choose to schedule the interconnection work, so long as they meet the IRS deadline. Utilities must offer first-scheduling opportunities for developers who opt in to an accelerated procedure and must supply preliminary work plans for the upgrades by May 1. Developers must pay for their share of the upgrades by June 1. Final work plans must be published no later than July 15.

The PSC also implemented some comments from the utilities, adding deadlines for developer system upgrade payments to utilities. If a project is at risk of not making the deadline, the PSC authorized utilities to consider alternatives.

Taken together, "this approach improves the utilities' ability to plan and deploy their engineering and construction resources to support tax-credit eligible projects, ahead of others that are not eligible," the PSC said in a press release. "Today's action also provides developers flexibility to manage the development of their projects as needed, while providing greater certainty that IRS in-service dates will be met." ■

| Shutterstock

Equinor Hopeful it Can Complete Empire Wind on Schedule

CEO Details Progress as Tussles Continue with Trump Administration

By John Cropley

Empire Wind developer Equinor says it's optimistic it can complete work on the $7.5 billion offshore wind project and start selling electricity to New York on schedule.

But the court fight continues with the Trump administration, CEO Anders Opedal said Feb. 4 during Equinor's *year-end earnings call*.

Work on the 810-MW project has been halted twice by the administration and resumed twice by the Norwegian developer, once with the administration's permission and once with a federal judge's preliminary injunction against the stop-work order.

In court papers, Equinor estimated the impact of the April 2025 halt at $200 million. Opedal told financial analysts that the company views both stop-work orders as illegal but said the December 2025 halt was much less costly.

He said work is more than 60% complete, with the offshore substation, nearly 186 miles of cable and all monopile foundations installed.

About $3 billion in capital expenditures remain on the $7.5 billion project, Opedal said. Revenue from operations ($155/MWh) and monetized federal investment tax credits (approximately $2.5 billion) should cover outlay of all known upcoming costs, he said, but added: "We, like other companies, remain exposed to uncertainty when it comes to possible future tariffs."

A financial analyst asked how Equinor feels now about retaining 100% ownership of Empire Wind, formerly a 50-50 venture with bp that was dissolved after the U.S. offshore wind industry ran into spiraling costs in 2023. (See *Offshore Wind Reset Complete in New York*.)

"This is definitely something to reflect on," Opedal said. "We normally don't take 100% in any license.

"We de-risked it somewhat with higher strike prices, with a financing package, and then as you've seen, the political risk with the new administration was higher than anticipated.

"This is a trend now we see in several countries," Opedal said, not just in the United States: Energy investments have become more politicized and polarized.

He will be looking for strong bipartisan support for future projects and considering carefully how to move forward with any project that proves divisive.

"With the political changes we've seen … we probably would have thought differently about Empire Wind in the past," Opedal said.

An analyst asked him to handicap the court fight in the United States.

"This is a little early to say," Opedal said. However, he noted the other four U.S. offshore wind projects also won injunctions against the Trump administration's December stop-work order, which is a promising sign. (See *With Sunrise Wind Ruling, OSW Industry now 5-0 Against Trump Admin*.)

"But I'm an engineer, not a lawyer," he added.

Equinor — originally and still primarily an oil and gas producer — also reported record fossil fuel production in 2025.

A financial analyst asked Opedal about Equinor's commitment to the energy transition amid its recent pullbacks.

"We are signaling a consistency around oil and gas," he said. The market view about offshore wind, hydrogen and particularly carbon dioxide transportation/storage has changed in recent years, he said, and Equinor's customers have postponed their emissions reduction plans.

"Everyone had a 2030 target," Opedal said.

Equinor will focus on wrapping up its existing offshore wind projects and place a "high bar" on any future investments in the sector, including through its investment in offshore wind leader Ørsted, he said.

Equinor reported 2025 net income of $5.06 billion or an adjusted $2.47/share on total revenues of $106.5 billion, compared with 2024 net income of $8.8 billion or an adjusted $3.24/share on total revenues of $103.8 billion. ■

Why This Matters

The developer is pushing forward against the continuing and shifting interference of the Trump administration.

The offshore wind hub Equinor is building in Brooklyn, N.Y., is shown in this aerial view. | *Equinor*

PJM: Lower Load than Expected During Winter Storm

By Devin Leith-Yessian

While PJM experienced some of its highest peak loads ever during the late January winter storm, it overestimated load, with relatively high load forecasting errors, RTO officials told the Operating Committee.

PJM's Paul Dajewski *told* the Operating Committee on Feb. 5 that while operations were strained during the Jan. 24-27 storm, named "Fern" by The Weather Channel, load did not quite reach the forecasted peaks and the RTO maintained reliability.

"We were able to operate through this period reliably; we did have sufficient generation reserves; we were able to serve our loads; we were able to serve our exports," Dajewski said, adding that PJM provided emergency energy sales to neighboring regions.

PJM saw an instant peak load of 140,049 MW on Jan. 29 at 8:05 a.m. and two new top 10 hourly integrated peaks of 139,046 MW on Jan. 29 and 138,479 MW the following day. It noted that the data are preliminary.

Dajewski said there was a lot of uncertainty with preparing for the storm, owing to the duration of the freezing temperatures, pipeline flexibility, fuel storage, generators running into emission limits, load forecast accuracy, and the interplay between when gas resources are committed and when they purchase fuel from pipelines.

PJM asked that generators cut short maintenance outages between Jan. 25 and Feb. 2, reducing some transmission constraints. The RTO declared a long-duration extreme event, so fuel-limited resources were required to signal when they have 32 hours or less of fuel inventory, rather than the standard 16-hour notice.

The load forecast error was high between Jan. 26 and 29, peaking with an 8% over-forecast on Jan. 27. PJM's Joseph Mulhern said temperatures were not quite as low as expected and that it's possible the RTO's modeling did not properly account for building closures. PJM said that it is difficult to predict the number of buildings that will close

PJM's Paul Dajewski discusses the grid's performance during January's Winter Storm Fern. | *© RTO Insider*

because of the weather, as the decisions are based on subjective, location-specific factors.

Stakeholders expressed surprise that building closures would contribute to load falling gigawatts below the forecast. Mulhern said PJM is exploring the issue further.

Transmission constraints and limited ramp capability drove $797.6 million in uplift costs, mostly in balancing operating reserve charges. There were $577.9 million in make-whole costs, $98.2 million in lost opportunity costs and $121.6 million in day-ahead operating reserve charges assigned. PJM is working on a more detailed breakdown of the make-whole costs for stakeholders.

Conservative operations were used to secure advance commitments, which PJM's Brian Chmielewski said contributed to the make-whole costs. Pre-emergency load management was called in the BGE, Dominion and Pepco zones Jan. 25 for localized transmission constraints, and maximum generation, load management and low-voltage alerts were issued for Jan. 27.

PJM's Brian Fitzpatrick said gas pipelines performed "very well," with only one compressor station failing and 1,500 MW of generation interrupted. Winterization efforts on gas production appear to have led to a decrease in reduced output during winter events, with 5% production lost in Appalachia and 9% across the country. Nonetheless, spot prices were some of the highest he has seen, reaching $300/MMBtu on some interfaces.

Even with actual load coming in below forecast, Fitzpatrick said there was a lot of concern in the gas market about the duration of the storm, high loads and potential scarcity.

"That inherent fear in the market drove those prices," he said.

PJM received Department of Energy waivers under Section 202(c) of the Federal Power Act to operate 39 units totaling 5.2 GW past environmental permit limits for 1,035 hours. The department also invoked a lesser used 202(c) provision to make backup generation available, but those units were not dispatched. (See *Wright Ready to Use Emergency Powers to Dispatch Backup Generation During Winter Storm*.)

PJM's Joe Ciabattoni said the day-ahead bid period was extended on Jan. 26 and 27 because of issues running credit checks on market participants. It took longer for staff to accept bids because of the number of offers exceeding $1,000, triggering the automatic offer verification process.

A severe cold snap Jan. 16-21 preceded the storm, but it was much easier for the RTO to manage, with no emergency actions taken. The generation fleet performed well, and no emergency procedures beyond cold weather advisories or alerts were required. Load peaked at 135,121 MW on Jan. 21 at 7:40 a.m. with no load management deployed.

While all pipelines enforced the restrictions in their tariffs, there was no drop-off in production, and fuel remained available and relatively affordable for dispatched units. No advance commitments were made in preparation. ■

PJM Stakeholders Considering Load Management Performance Penalties

By Devin Leith-Yessian

PJM, Voltus and the RTO's Independent Market Monitor presented proposals to establish penalties for demand response and price-responsive demand (PRD) resources that fail to perform during a pre-emergency load management event.

Penalties are being considered after a summer of poor performance in 2025, when six pre-emergency load management events totaling 30 hours had a weighted average performance of 67%. PJM has no penalties in place for poor performance outside a performance assessment interval (PAI). (See "PJM Proposes Performance Penalties for Non-emergency Load Management," *PJM MIC Briefs: Jan. 7, 2026*.)

The PJM *proposal* would penalize resources with poor performance at half the rate for PAI events, which is around $2,300/MWh for the 2027/28 delivery year. That would be accomplished by mirroring the PAI penalty formula but doubling the number of expected deployments for pre-emergency events to 60.

PJM's Pete Langbein suggested the modeled number of deployments might be worth considering further, noting there have already nearly been 60 events this delivery year. He presented the PJM solution to the Market Implementation Committee on Feb. 4.

The allocation of revenue collected through the penalties was revised since the January MIC meeting so bonuses would be evenly split between load-serving entities (LSEs) and curtailment service providers (CSPs) if overall performance were deficient. If the fleet overperformed during an event, the bonuses would be entirely allocated to CSPs.

Monitor Proposal Seeks to Withhold Market Revenues

The Independent Market Monitor *proposal* would withhold daily capacity payments from underperforming resources going back to the last event or test where they met their obligations to their next successful deployment. The payments would be pro-rated to scale with the shortfall.

The Monitor argued that PJM's proposal undermines the incentive to improve performance by allowing lagging resources to continue collecting significant revenues. It gave an example of a 100-MW resource that does not curtail at all during a 12-hour deployment; it would be assessed a $1.4 million penalty under the PJM proposal, which is 12.2% of its annual capacity revenues.

Pete Langbein, PJM | © *RTO Insider*

Why This Matters

Penalties are being considered after a summer of poor performance in 2025, when six pre-emergency load management events totaling 30 hours had a weighted average performance of 67%.

For proposals including a penalty, the Monitor wrote that the associated revenues should be allocated entirely to LSEs.

The proposal would adjust the effective load-carrying capability rating for individual resources based on their historic performance, and PRD accreditation would be set at the lesser of a unit's summer or winter nominated installed capacity.

Voltus Reworks Proposal

The Voltus *proposal* would set the penalty rate at 8.3 to 25% of the PAI rate, depending on the number of non-emergency load management hours modeled and the share of net cost of new entry (CONE) it was designed to recover. Net CONE would be reduced by a quarter to half to account for the reduced reliability risks with a pre-emergency event, and the number of events would be assumed to be two to three times greater than 30 PAI hours.

The penalty revenues would be allocated to overperforming resources with a cap 1.2 times the penalty rate; any remaining funds would go to LSEs.

Voltus proposed reducing the penalty and increasing the bonus cap should the number of non-emergency events exceed the amount modeled to reduce dispatch fatigue. The prospect of deployments becoming increasingly common as the capacity market tightens has led to alarm bells from CSPs who have argued that many participants will drop off if the financial impact of curtailments exceed their capacity market revenues. ■

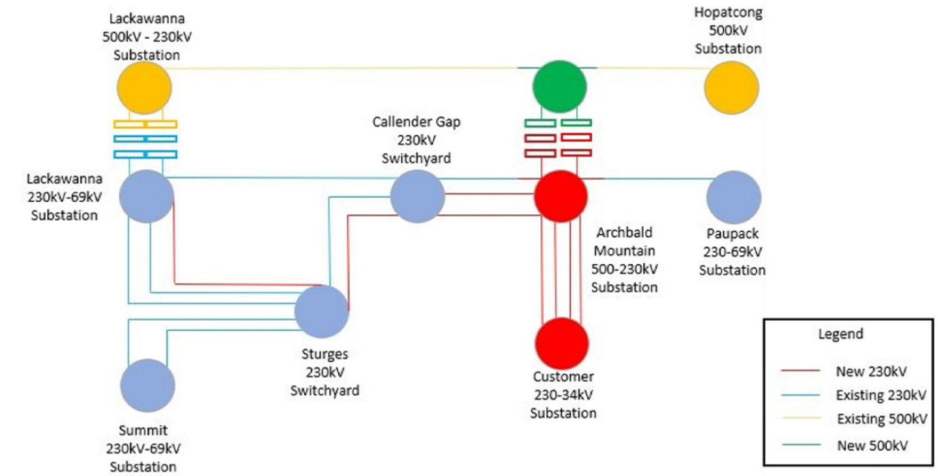
PJM PC/TEAC Briefs

Planning Committee

PJM Presents Quick Fix Proposal on Battery Dispatch Modeling

PJM's Julia Spatafore *presented* a quick-fix proposal to model battery storage dispatch in Regional Transmission Expansion Plan base cases. The quick-fix process allows an *issue charge* and *problem statement* to be brought alongside a solution.

Battery units are modeled as offline under Manual 14B: PJM Region Transmission Planning Process, which would be revised to allow them to be dispatched in the block dispatch methodology. The resources are already modeled as online in generation deliverability studies, a misalignment Spatafore said would be closed by the proposal. The change would also increase the generation available when planning transmission and support state policies promoting storage.



PPL presented a $220 million project to serve a customer seeking to bring 1 GW of load to Archbald, Pa. | *PPL*

Transmission Expansion Advisory Committee

Transmission Projects for Large Loads

Dayton Power and Light *presented* a $246 million transmission project to supply an 800-MW service request of load near the Darby substation in Marysville, Ohio. A 765/345-kV substation, named Patina, would be cut into the existing 765-kV Marysville-Flatlick line. Two new 5-mile 345-kV lines would connect Patina to a new 345-kV substation, named Weaver, serving the customer. The project has an in-service date of May 1, 2031, and is in the conceptual phase.

Exelon *presented* a $263.5 million project in the BGE zone to serve an 880-MW customer near the Calvert Cliffs nuclear plant in Maryland. A 500-kV substation, named Camp Canoy, would be constructed with a 175-MVAR, 500-kV capacitor bank. It would be cut into the 500-kV Calvert Cliffs-Waugh Chapel and Calvert Cliffs-Chalk Point lines. The customer is seeking to come online in 2028 with 190 MW before reaching full capacity in 2030. The project is in the engineering phase, with a projected in-service date of March 1, 2028.

Exelon also *presented* a $245 million project in the ComEd zone to serve a customer seeking to bring 504 MW to the DeKalb, Ill., area. Two 345-kV substations, Charter Grove and Gurler, would be constructed to link the customer to the 345-kV Bryon-Wayne line. Charter Grove would cut into Bryon-Wayne, and a 16-mile 345-kV line would connect it to Gurler. A 1.5-mile 345-kV line would connect Gurler to the Keslinger substation, and two 345-kV lines would link it to the customer. The load is expected to come online in 2029 at 12 MW and ramp to 504 MW in 2033.

A $269 million project in ComEd would serve a 1.8-GW customer near Joliet, Ill., by constructing a new 345-kV substation, named Rowell, featuring two 150-MVAR, 345-kV capacitor banks. It would cut into the 345-kV Elwood-Goodings Grove line and link to four customer-owned substations. The customer is expected to come online in June 2029 with 225 MW and ramp to its full consumption in 2033. The project is in the conceptual phase, with an estimated in-service date of July 1, 2028.

A $145 million ComEd project is planned for a 1,296-MW customer near Coal City, Ill., involving the construction of a 345-kV substation, named after the village, with two 150-MVAR, 345-kV capacitor banks. It would cut into the 345-kV Dresden-Pontiac Midpoint and Lasalle-Braidwood lines. The customer is seeking to bring 216 MW online in June 2029 and grow to its full load in 2034. The project is in the conceptual phase with an estimated in-service date of July 1, 2028.

A $99 million project in ComEd would serve a 1-GW customer near Joliet by constructing a new 345-kV substation, named Hiawatha, with one 150-MVAR, 345-kV capacitor bank. It would cut into the 345-kV Kendall County E.C.-Collins line and feed two customer-owned substations with two 0.7-mile radial lines. The customer is seeking to come online with 30 MW in June 2028 and reach its full load in 2032. The project is in the conceptual phase with an estimated in-service date of June 1, 2028.

PPL *presented* a $220 million project to serve a customer seeking to service 1 GW of load in Archbald, Pa. A new 500/230-kV Archbald Mountain Switchyard would be constructed, cutting into the 230-kV Callender Gap-Paupack and the 500-kV Lackawanna-Hopatcong lines. Archbald Mountain would be connected to Callender Gap with a new 4.6-mile double-circuit 230-kV line and to the customer substation with a 4-mile single-circuit 230-kV line. The customer is expected to come online with an initial load of 166 MW in 2027 and reach 900 MW by 2030, before reaching 1 GW the following year. The project is in the development phase, with a projected in-service date of May 30, 2028.

Dominion Energy *presented* three projects to serve data centers in Caroline and Spotsylvania counties and Petersburg, Va. They total $106 million and would serve at least 912 MW. ■

— Devin Leith-Yessian

PJM MIC Briefs

Stakeholders Endorse Storage Issue Charge

PJM's Market Implementation Committee passed by acclamation a PJM *issue charge* seeking to more thoroughly define how storage resources participate in the energy and ancillary service markets.

Much of the focus was on PJM's obligation under FERC Order 841 to implement storage state of charge in its energy storage resource rules, as well as how lost opportunity costs (LOCs) are determined. The issue charge was revised after January's first read spelling out that the LOC discussion should consider how the timing of PJM dispatch interacts with changing prices, emergency conditions and supply/demand balance.

The list of additional items for consideration was expanded to include cost-based energy offers, calculation of uplift, LOC rules for storage participating in energy and ancillary service markets, and whether pumped storage hydro resources should be part of the conversation. It also includes must-offer rules for storage resources with capacity commitments, intraday offers, cost-based offers and resource parameters.

The out-of-scope section includes changes to resource adequacy, performance assessment interval and effective load-carrying capability modeling for storage; surplus interconnection service; storage as a transmission asset; the pumped hydro optimizer; and peak shaving adjustments. A sixth key work activity was added for a possible second phase to explore out-of-scope topics.

The issue charge envisions governing document and manual revisions being drafted within six to nine months, which stakeholders said is an appropriate timeline given the numerous other market redesigns being considered.

Carl Johnson, representing the PJM Public Power Coalition, said it's important that PJM's planning and markets departments both be involved in the stakeholder discussion and remain aware of the changes being made. In particular, planning models should account for any changes to how storage resources offer into the energy market.

Constellation Proposes Dual-fuel Quick Fix

Constellation presented a quick fix *proposal* to revise the must-offer requirement for dual-fuel capacity resources to recognize that dual-fuel gas resources have a downtime when switching fuels. The quick fix process allows an *issue charge* and *problem statement* to be brought concurrent with a proposed solution. The proposal is set to be voted on by the MIC at its March 11 meeting.

The proposal would specify that a dual-fuel resource met its must-offer requirement so long as it submits offers including the primary and alternate fuels

PJM Monitor Joe Bowring | © *RTO Insider*

within "limitations or restrictions resulting from fuel switching time modeling within PJM's software platforms." The language would be added to the capacity resource offer rules in Manual 11: Energy & Ancillary Services Market Operations.

Stakeholders said there may be differences in how units switch fuels or in the details of that switching period. They said a broad change that applies to all dual-fuel resources could help avoid the must-offer requirement.

ARR and FTR Timeline

PJM laid out the *schedule* for the 2026/27 auction revenue rights (ARRs) and financial transmission rights (FTRs) markets. Stage 1A of the annual allocation begins on March 4 before moving on to stage 1B on March 10. Stage 2 begins on March 18.

Trading for ARRs begins on April 2, while the annual FTR auction starts April 8. ■

— Devin Leith-Yessian

PJM OC Briefs

Stakeholders Endorse Order 881 Manual Revisions

The PJM Operating Committee endorsed a set of manual *revisions* to implement ambient-adjusted line ratings (AARs) in compliance with FERC Order 881. (See "Manual Language to Implement AARs Endorsed," *PJM OC Briefs: Jan. 8, 2026*.)

The changes to Manual 3: Transmission Operations, and Manual 3A: Energy Management System Model Updates and Quality Assurance, will create a system where temperature-adjusted line ratings are produced 248 hours out, including a

| © *RTO Insider*

buffer of eight hours to ensure compliance with Order 881. Monthly ratings also will be produced, which PJM's Ryan Nice noted goes beyond the order's seasonal requirement.

The changes are set to take effect March 4. Nice said any transmission owners with concerns about being prepared for the launch date should reach out to him.

Grid Security Drill

PJM's Ed Figuli *announced* plans to hold the annual grid security drill Nov. 17, with invitations planned to go out in March. The drill focuses on cyber and physical security and is open to state and government agencies, in addition to PJM members. ■

— Devin Leith-Yessian

Wind Output Enabled SPP Exports to Neighbors During Storm

Grid Operator Sent as Much as 3,500 MW Eastward

By Tom Kleckner

LITTLE ROCK, Ark. — In preparing his first presentation to stakeholders as SPP's operations vice president, C.J. Brown said he found himself staring at a blank slide.

"What am I going to talk about?" he had asked himself.

"I've regretted that statement because as soon as I thought that, I got a message about Winter Storm Fern," Brown told stakeholders during the RTO's quarterly update Feb. 2, referring to the late January frigid precipitation and cold. "Anytime a storm has a name that early in a week, it's just not going to be a good deal."

SPP issued a conservative operations advisory — the final notice before calling an energy emergency alert — during the storm, but above-average wind generation saved the day. Brown said forecasts of 11 GW were threatened by a risk of more than half that being knocked offline. However, the lack of icing conditions allowed wind resources to meet projections.

"Wind produced above accreditation by a significant amount … pretty much throughout the event," Brown said. "Ultimately, we were very strong in that category, which allowed us to be able to support a lot of those in the Eastern Interconnection that were short. Wind was a large part of the story."

The RTO continually exported energy to the east during the event, Brown said, peaking at around 3,500 MW. Thermal outages reached about 15 GW during the storm, but SPP was able to lean on its extra generation to help other grid operators.

The lowest temperatures came in the

A snowy landscape greets visitors to SPP's offices. | © *RTO Insider* morning hours of Jan. 26, when demand reached a winter high of around 46 GW. Brown credited infrastructure investments and generation, system and transmission operators working together to help SPP breeze through the storm.

"It certainly takes a village to get through these storms," Brown said.

SPP staff and the Market Monitoring Unit have both promised full reports on the grid operator's storm response.

Nickell Thanks Members

More than 10 inches of snow and sleet fell on Little Rock during the storm. The wintry mix was then sealed by a layer of ice that made removal difficult. A week after the storm, many of the city's side streets were still impassable, and mounds of white slush were piled high in parking lots.

The city's school district canceled classes for the week, leaving many residents stranded in their homes amid subfreezing temperatures. Chuck Hutchison, a member of the Nebraska Power Review Board, noted temperatures were lower in Omaha than in Little Rock the day before the quarterly briefing.

"We really wanted to make our commissioners from North Dakota and South Dakota feel more at home. Plenty of snow," SPP CEO Lanny Nickell said in welcoming the Regional State Committee. "I'm sure [the snow] makes a lot of you feel more comfortable if you're coming from the northern part of our region. We don't like it down here."

He thanked members with "heartfelt gratitude" for their efforts and collaboration in avoiding regionwide outages.

"It does mean a lot to be able to work as closely as we do with all of you who serve customers and have that responsibility to work with us to keep the lights on," he said. "The fact that it was a significant winter storm and we survived says a lot [about] the hard work that we have been doing since [2021's] Winter Storm Uri, the policies that we put in place, [and] the procedures that I know our operators and your operators have improved to make better decisions well ahead of time so that we can keep the lights on, keep people warm and make sure that lives are saved."

Casey Cathey, SPP | © *RTO Insider*

Accelerating Grid Infrastructure

Casey Cathey, vice president of engineering, said staff are hoovering "all things transmission" to accelerate grid infrastructure and capacity through its Project Keystone, including 765-kV and other large transmission projects, the 2026 transmission plan, cost allocation and the transition to the Consolidated Planning Process. (See *SPP 'Blazes Trail' with Consolidated Planning Process*.)

"We're scooping those up and making sure that we're working those in tandem and collectively for a successful implementation of what we may need moving forward as a region," he told stakeholders.

SPP is working with the Economic Studies and Transmission working groups to modify the 2026 Integrated Transmission Plan's scope and address confusion over the proposed 765-kV overlay. The board approved four 765-kV projects in November 2025 but deferred several others from the $8.6 billion portfolio and committed to analyze the 765-kV overlay in the 2026 ITP assessment. (See *SPP Board Approves 2025 ITP with 4 765-kV Projects*.)

Staff will codify the overlay's explanation for the Markets and Operations Policy Committee's meeting in April. The 2026 assessment is on track, Cathey said, with the 30-day submission window for project proposals opening in late February.

"The 2026 ITP is looking to be our largest portfolio. We are anticipating tens of thousands of needs to solve," he said. "The forecasts that we see in the 2026 ITP are that much greater than what we see in the 2025 ITP and what drove our four 765 facilities."

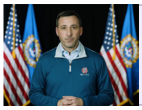
Cathey dismissed talk of an AI bubble and said load requests from the 2025 assessment remain, with some accelerating from Year 5 to Year 2 in plans.

Hanging over Project Keystone is what Cathey calls the "cost problem."

"It's billions of dollars that we're talking about on top of billions of dollars that were already approved, and that's a lot more than we're used to as a region," he said. "We need to do whatever we need to do to make sure that we're balancing encouraging these loads to show up with the region, but also that we're fair to the existing ratepayers." ■

National/Federal news from our other channels

CISA Guidance Emphasizes Insider Threat Readiness — ERO Insider



FBI Releases Critical Infrastructure Cyber Recommendations — ERO Insider

Stakeholders Urge Further Refinement of Standard Modernization Proposals — ERO Insider

RTO Insider subscribers have access to two stories each month from *NetZero* and *ERO Insider*.

Xcel, NextEra to Partner on Generation for Data Centers

By Tom Kleckner

Xcel Energy's leadership says a partnership with NextEra Energy will allow its operating companies to contract up to 6 GW of data center capacity by the end of 2027, with sales and generation investment ramping into the next decade.

"We think there'll be increased clock speed as we think through combining the best sales teams, the best development teams and the best analytical teams in the country to deliver solutions for a very sophisticated customer set," Xcel CEO Bob Frenzel told financial analysts during the company's Feb. 5 year-end earnings call.

The companies the day before had *announced* a memorandum of understanding to co-develop generation, storage and interconnections for data center projects. They said the agreement will support existing and new large load opportunities across Xcel's service territories by better anticipating system needs, streamlining development timelines and advancing innovative grid technologies.

"It brings scale and the ability to put an inflection point in the curve of data center delivery and signed [energy services agreements] and contracts and, ultimately, investment opportunities in all three of our big regions," Frenzel said.

Xcel Energy CEO Bob Frenzel | © *RTO Insider*

He said conversations with data center developers have affirmed Xcel's position that they don't want to own and operate their own generation.

"We don't want you to take existing supply out of the stack," Frenzel said. "[Data centers] would rather have someone own and operate for them in a deregulated market. That means me working with the developer to build that generation, leave it through a regulated utility and sell it to the customer."

Xcel currently has more than 2 GW of new contracted data center capacity and a 3-GW goal by the end of the year. The company has more than 20 GW of capacity in its large load pipeline.

The Minneapolis-based company *reported* 2025 diluted earnings of $2.02 billion ($3.42/share), compared with $1.94 billion ($3.44/share) for 2024. It attributed the results to increased recovery of infrastructure investments and sales growth, partly offset by higher interest, depreciation, and operating and maintenance expenses.

Xcel reaffirmed its 2026 guidance range of $4.04 to $4.16/share. It has led or exceeded ongoing guidance for 21 consecutive years.

The company's share price Feb. 5 closed at $76.12, down 8 cents from its previous close.

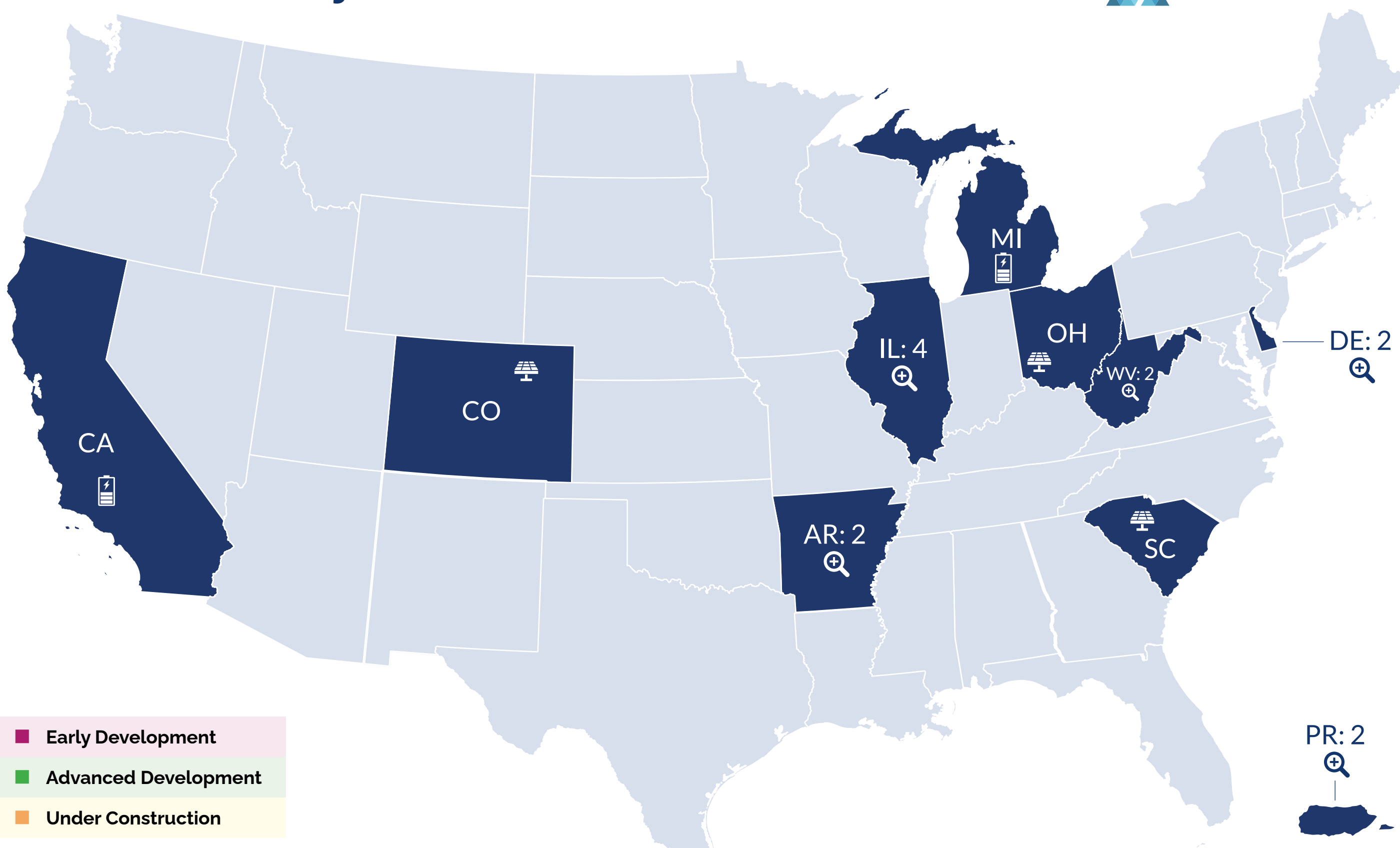
In a nod to the violent immigration enforcement taking place in Xcel's hometown, Frenzel said he was pleased to sign an *open letter* alongside more than 60 other CEOs urging a solution to the turmoil.

"It goes without saying that the tragic events across the Twin Cities have weighed heavily on our communities, our customers and our employees," he said. "We have engaged extensively and proactively with senior federal, state, local and community officials with a goal to de-escalate and identify a sustainable path forward."

Xcel's Energy Foundation has committed to help fund the Minneapolis Foundation and support local and small businesses affected by the events. ■

Generation Projects Added in the Past Week

YES ENERGY



Early Development
Advanced Development
Under Construction

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
	Independence Gas Plant CT 3 & 5	Arkansas Electric Cooperative Corp		AR	1,500	2032
	Independence Gas Plant ST 4 & 6	Arkansas Electric Cooperative Corp		AR		2032
	Soleil Renewable Energy BESS	Younan Company		CA	460	2036
	Greeley Solar (unofficial name)	Energy Capital Partners	Pivot Energy	CO	10	2027
	Bridgeville Solar (unofficial name)	Turningpoint Energy		DE	6	2027
	Harrington Solar (unofficial name)	Turningpoint Energy		DE	6	2027
	Truitt Rd Site 1	Brookfield Asset Management	Luminace	IL	2	2026
	Truitt Rd Site 2	Brookfield Asset Management	Luminace	IL	2	2026
	Huntley Solar (unofficial name)	Oneenergy Renewables	OneEnergy Development LLC	IL		2028
	Route 40 Solar	Brookfield Asset Management	Luminace	IL	2	2026
	Coldwater Solar (Ovid Solar) BESS	Apex Clean Energy		MI	75	2027
	Center Hill Landfill Solar (unofficial name)	Ownership Undisclosed		OH	10	2027
	Naguabo BESS	Ownership Undisclosed		PR	80	2028
	Yabucoa BESS	Ownership Undisclosed		PR	20	2028
	St. Charles Solar	Duke Energy	Duke Energy Progress	SC	145	2031
	Twisted Gun Solar	MN8 Energy LLC		WV	170	2029
	Twisted Gun Storage	MN8 Energy LLC		WV	70	2029

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

Siemens to Spend $1B Expanding U.S. Turbine, Grid Factories

Siemens Energy committed $1 billion to expand its U.S. manufacturing base as the nation faces surging demand for gas turbines and power grid equipment.

Factories will be expanded in Alabama, Texas, New York and Florida, and Siemens will restart a gas turbine manufacturing plant in North Carolina. In addition, a new factory will be built in Mississippi for manufacturing switchgears.

The company will also partner with Nvidia to build an AI digital grid technologies laboratory in Orlando, Fla. It will use AI to analyze real-world grid data to use existing resources better and to aid in disaster preparation and recovery.

More: *The New York Times*; *E&E News*

Dominion: CVOW Cost Rises to $11.5B

Dominion Energy said the cost of its Coastal Virginia Offshore Wind (CVOW) project will increase by $300 million, according to a filing with the Securities and Exchange Commission.

The company said the increase, up from $11.2 billion to $11.5 billion, is tied to additional estimated costs associated with tariffs and a December 2025 stop-work order by the Trump administration.

Dominion said CVOW will begin delivering power during the first quarter of 2026, with the entire project expected to be completed in early 2027.

More: *Virginia Business*

Meta, Zelestra Sign Solar PPA

Spanish renewables company Zelestra has signed a long-term power purchase agreement with Meta to deliver electricity from its 136-MW Skull Creek solar plant in Texas.

The deal expands on an existing off-take partnership between the companies, which now covers seven solar projects across the U.S. with a combined capacity of nearly 1.2 GW.

All the projects are scheduled to be operational by 2028.

More: *Renewables Now*

Federal Briefs

DOE Seeking State Partnerships on Nuclear Power

The Department of Energy announced it is seeking states interested in housing regional hubs that could support several parts of the nuclear fuel cycle. That includes fuel fabrication, enrichment, reprocessing used nuclear fuel and nuclear waste storage.

"Nuclear Lifecycle Innovation Campuses" are the first step toward establishing federal-state partnerships centered on building an end-to-end nuclear energy strategy for the country, the DOE said. The Trump administration wants to quadruple the production of nuclear power in the U.S. over the next 25 years, and a permanent repository for the radioactive waste will be needed to achieve that goal.

More: *Nevada Current*

DOE Requests Input on Advancing AI for Genesis Mission Challenges

The Department of Energy announced a Request for Information to solicit public and private sector input on strategies for meeting the technical challenges of the Genesis Mission. It also seeks input on developing a workforce to advance artificial intelligence in science and engineering.

The Genesis Mission aims to mobilize DOE's National Laboratories, industry and universities to harness the nation's capabilities in high performance computing, next-generation quantum computers and AI to revolutionize science innovation.

The deadline for responses is March 4.

More: *Department of Energy*

State Briefs

ARKANSAS

PSC Approves Entergy Natural Gas Plant

The Public Service Commission approved Entergy's request to build a new natural gas plant, called Jefferson Power Station, near the White Bluff coal plant.

The plant will cost Entergy around $1.5 billion and will produce 754 MW.

Entergy said while it looks to take the White Bluff coal plant offline by the end of 2028 due to a settlement with the Sierra Club, the new plant will help the company meet increasing demand.

More: *Arkansas Times*

PSC OKs SWEPCO Rate Hike

The Public Service Commission released an order approving a rate hike for Southwestern Electric Power Company (SWEPCO).

The increase aims to boost the company's revenue by $85 million – which equals a bill increase of about $24/month for the average residential customer – to recoup costs for out-of-state wind farms, infrastructure upgrades and upgrades to the Flint Creek coal plant. The upgrades could keep Flint Creek burning coal until 2038. As part of the decision, SWEPCO will also have to release a study modeling the impacts of retiring Flint Creek early in 2030 and 2035.

More: *Arkansas Times*

COLORADO

PUC Approves Xcel Renewable Projects

The Public Utilities Commission approved an expedited list of 1,700 MW of projects for Xcel Energy, hoping to get the projects started before federal tax credits expire.

The PUC approved bids for a 200-MW natural gas plant, 600 MW of wind and 300 MW of battery storage. Some of it would be owned by Xcel Energy and some purchased on long-term contracts. Xcel had proposed a project portfolio totaling 4,900 MW.

An additional 1,000 MW of solar and 700 MW of storage will be needed, PUC Chair Eric Blank said, and the final portfolio will range between 3,200 MW and 3,500 MW.

More: *The Colorado Sun*

KENTUCKY

Bill Would Prevent Utility Shutoffs During Extreme Weather

Lawmakers are forming a bipartisan push for a bill that would stop utilities from disconnecting customers during extreme temperatures.

The bills would stop disconnections during temperatures below 32 degrees Fahrenheit and above 95 degrees. Kentucky is one of eight states without disconnection protections.

More: *WKYT*

LOUISIANA

Natural Gas Pipeline Explodes in Cameron Parish

One operator was injured when a pipeline operated by liquefied natural gas developer Delfin LNG exploded Feb. 3.

The pipeline is 28 miles long and connects to a rig offshore. Natural gas was cut off at the rig as officials let the fire burn out.

Officials said there were no off-site impacts from the explosion, while state police will investigate the cause.

More: *KPLC*

MARYLAND

House Caps Ratepayer Contributions to Utility Salaries

The House of Delegates voted to set new limits on the use of ratepayer dollars to pay salaries for employees of investor-owned utilities.

Under the bill, investor-owned utilities can pay their supervisory staff whatever compensation they deem fit, but only a certain amount can be recouped using money from customers. The cap is set around $250,000 annually.

The Senate is debating a similar bill.

More: *Maryland Matters*

NORTH DAKOTA

PSC Approves Xcel Rate Increase

The Public Service Commission approved a 10.37% rate increase for Northern States Power, a subsidiary of Xcel Energy.

Customers were already paying a higher rate in 2026 under an interim rate increase. The average residential customer was paying $11.36 more each month under the interim rate. The final rate increased that by an additional 58 cents — $11.94 more than before the rate increase request.

More: *North Dakota Monitor*

OHIO

Power Siting Board Approves Natural Gas Power Plant

The Power Siting Board approved construction of a 350-MW natural gas-fired power plant in Wood County.

The facility, known as the Apollo Power Generation Facility, will be built and operated by Will-Power OH. The plant will operate "behind the meter," meaning all electricity will serve the load of an adjacent data center and will not feed into Ohio's grid. The project will also contain 120 MW of battery storage capacity.

More: *The Scioto Post*

VERMONT

Clean Heat Standard will not Go into Effect

The state's Clean Heat Standard will not go into effect after the Public Utility Commission officially closed the case following the legislature's failure to take a required vote.

The legislation would have created a credit marketplace to wean residents off fossil fuels. Lawmakers passed the legislation two years ago over Gov. Phil Scott's veto; however, the law required another affirmative vote from the legislature before implementation, and lawmakers never voted on the measure.

More: *WCAX*

VIRGINIA

House Passes Bill Prohibiting Solar Bans

The House voted 63-33 to pass a bill that would prohibit solar project bans by local communities.

The bills would prevent localities from passing ordinances that outright ban a solar project or have requirements that effectively ban them by limiting them to unsuitable areas. Local governments would have to consider and follow a set of development standards prescribed in the bills.

The Senate's version of the bill previously passed 21-17. The bills now head to the opposite chamber for final debates.

More: *Inside Climate News*