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YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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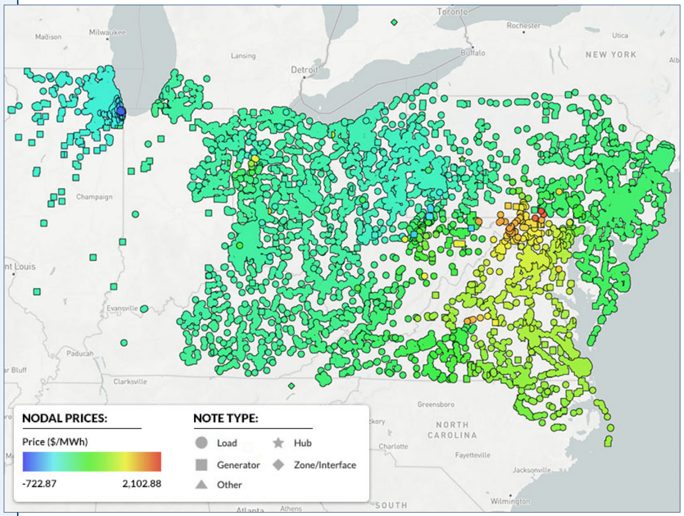
FERC/FEDERAL | PJM

Power Grid Weathers Winter Storm Fern, Faces Continued Cold Snap



Yes Energy

The winter storm and related cold snap are giving the bulk power system its first test of 2026 as prices shot up in many markets and hundreds of thousands lost power because of distribution outages.

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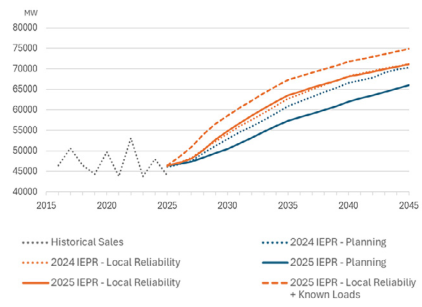
CAISO/WEST



California Energy Commission

EVs Outrank Data Centers in California Electricity Demand Forecast (p.17)

The CEC signed off on a forecast showing the state's electricity consumption could surge by as much as 61% over the next 20 years, but it pegs the biggest driver as increased EV use.

SPP | CAISO/WEST

Tri-State Generation and Transmission Association

Colo. PUC Sticks with Approval of Markets+ for PSCo (p.49)

The commission's decision keeps PSCo on track to begin Markets+ participation in 2027.

ISO-NE

Hydro-Québec

Hydro-Québec Halted NECEC Deliveries amid Reliability Concerns (p.27)

The suspension of supply on the new transmission line amid tight system conditions in New England likely led to significantly higher energy prices and is a potentially concerning sign for the project's near-term reliability benefits.

RTO Insider
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In this week's issue

Drought Magnifies and Complicates Climate Change's Impact on the Grid

Not Just Loss of Hydropower; a Systemic Threat to the Electric Grid

By Dej Knuckey

Dej Knuckey

Less than five years ago, California's Lake Oroville was so empty its 644-MW Edward Hyatt Power Plant, a pumped-storage hydroelectric plant, was shut off for the first time since it came online in 1967. The state was in a drought so long and severe that many areas had water restrictions, most reservoirs were at or near record lows, nearly 400,000 acres of farmland were idled, and close to $1 billion worth of crops were lost.

Almond trees in general, and the billionaire couple who own Wonderful Foods specifically, found themselves on the public enemies list again after a 2016 Mother Jones expose uncovered their substantial water use. But neither almonds nor pomegranate juice — nor even billionaires — were mostly to blame. La Niña bore the brunt of the blame for the drought that gripped the West, and climate change exacerbated it.

The hydropower shutoff was just one of the energy-related impacts of the drought. Throughout this extreme dry spell, the water-energy nexus was laid bare.

Today, we need to think of drought as more than an agricultural or wildfire-risk problem; it's a systemic threat to the electric grid. Drought, like other weather extremes, undermines supply, drives up costs and exposes weaknesses in our infrastructure planning.

When it Rains, it Pours (And When it Doesn't...)

The irony of researching this article the same month California was declared drought-free for the first time in 25 years is not lost on me. When I returned to Northern California from my holiday break, it was raining. Hard. With the 101 freeway closed in both directions thanks to the storm coinciding with a king tide, my last piece on sea level rise seemed relevant. But drought? It was far from top of mind.

Compared to other climate extremes covered in this series, I assumed drought's impact on the grid would be both obvious and tangential. More drought means less hydropower generated. Hardly a story. But digging deeper, it's clear that drought should be thought of as a problem multiplier when it comes to our energy system.

As climate change progresses, we have to build a grid that can handle heat waves, wildfires and extreme drought, as well as extreme precipitation and sea level rise. It's a complex challenge that will get more urgent as climate swings become more extreme.

The Tangled Water-energy Nexus

The intersection of water and energy is, to put it mildly, complex.

Water is used to produce energy directly (hydropower), is heated to produce steam to produce energy (thermoelectric plants with steam turbines), cools that steam as it leaves the turbine and is pumped underground to capture geothermal energy. Water also acts as a battery in pumped-storage hydroelectric plants, which pump it up during off-peak hours for later release.

Water also consumes energy when it's pumped up from aquifers, conveyed from one location to another, treated so it's potable and heated for those long showers we love. In California, those uses consume at least 12% (possibly as much as 19%) of all electricity on the grid. Nationally, it's lower, with 4% of total electricity generated used for drinking and wastewater services.

Drought affects the physical grid too. When aquifers are pumped out, the ground above can subside as the pockets of ground that had held water collapse. In California's San Joaquin Valley, decades of drought-driven aquifer pumping have caused land to sink by a foot a year, damaging roads, pipelines and overhead utility infrastructure.

Phoenix Lake, one of the reservoirs in Marin Water's catchment system, during the 2021 drought. Husband and dog for scale. | *Dej Knuckey*

Then there are the less obvious intersections. Water conveys inputs for the energy system, such as coal barges on the Mississippi: 11% of all coal used by power plants is delivered by barge, and under this administration, coal-fired plants are being revived. And the correlation between rising electricity demand and water demand is high in the booming data center sector, creating stress on both systems.

Drought as a Problem Multiplier

With water woven so tightly into the energy system, drought becomes an electricity problem too.

The most obvious impact of drought is a decline in hydroelectric output. Conventional hydroelectric plants in the U.S. contribute about 6% (240,000 GWh) of total *utility-scale electricity* generation. Pumped-storage hydro adds 23 GW of storage capacity.

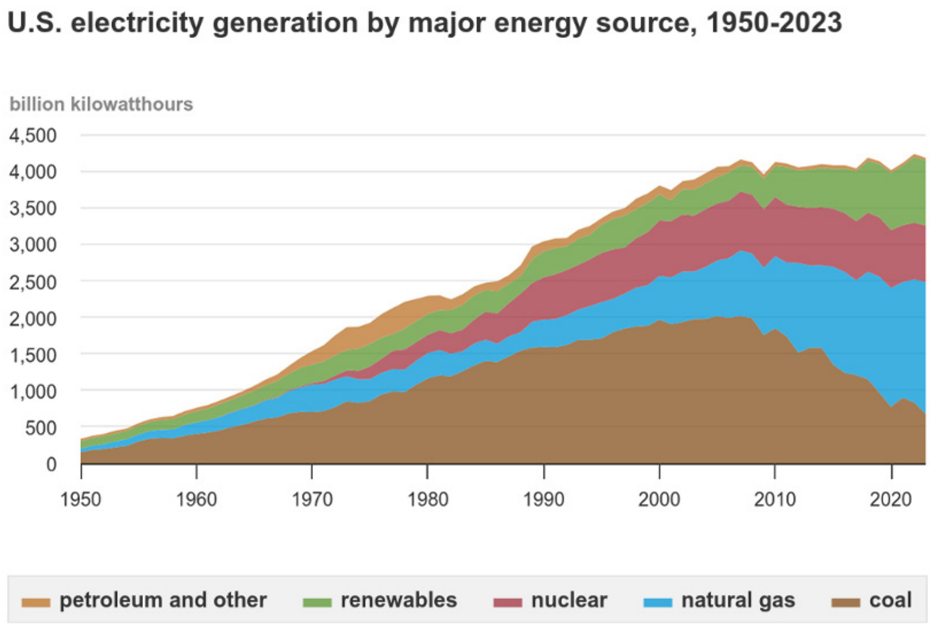
For hydro asset owners, drought has a real cost: A 2024 study found the sector lost 300 GWh of production and $28 billion of revenue over the 2003-2020 period. The period following the study saw droughts worsen. In the *2022-23 water year*, Western U.S. hydropower output was the lowest since 2001.

Drought also has cross-border trade implications. The U.S. typically imports electricity from Canada, where hydroelectric plants generate more than 60% of the electricity. In September 2023, drought in Canada reversed that flow, *making Canada a net importer* for five of the following nine months. While Canadian imports account for less than 1% of U.S. electricity, the exchange plays an important role in grid balancing.

The Drought-demand Spiral

Drought increases energy demand. In the agricultural sector, there's more energy used to pump water from the aquifer to water crops. Despite a water shortage, some end users, such as golf courses, will increase their water use, meaning more water is treated and pumped before it reaches the green. Droughts often coincide with hotter weather, when the demand for air conditioning rises.

Droughts also increase the risk of wildfires, with bone-dry vegetation more vulnerable to any spark from the grid. And even if the grid's not the cause of the fire, fighting those fires draws on water supply. The devastating Palisades fires a year ago were exacerbated when electric utilities de-energized lines, leaving *water utilities unable to pump enough water* to keep the fire hydrants at full pressure. Even without the outage, the unprecedented demand on the hydrant system would have been almost impossible to meet, exposing the need to provide battery backup to critical infrastructure, including water pumps.



As renewables have produced a larger portion of the electricity supply, the dependence on water-cooled thermoelectric plants has declined. | *EIA*

Water as a Power Plant Input

It's a misnomer to say energy is one of the largest users of water in the same way that it's a misnomer to say wind farms take up massive amounts of farmland. Water used in energy production largely continues its sea-bound journey after use, though warmer than before, in the same way farmlands continue being productive as cattle graze under the wind towers.

Power plants that use energy to cool steam are impacted by drought only when there's not enough water to intake. Thermoelectric power plants, including coal, natural gas, nuclear, oil and biomass, are becoming both a smaller part of the nation's electricity supply and more water-efficient. Wind and solar generators have grown from 4% of total utility-scale generating capacity in 2010 to 18% by 2021, so the portion of our power system dependent on water has fallen.

Still, thermoelectric power plants, almost all of which depend on water, provide about three-quarters of the electricity on the grid. They cool the steam from their turbines in *one of three ways*: once-through, where water is taken from rivers, lakes and aquifers and released back hotter; closed-loop or wet-recirculating, which reuses the water once it's literally let off some steam in cooling towers; or dry-cooling, which uses air to cool the steam.

Most of the water withdrawn by once-through systems is discharged back into the place it came, not contributing to the drought; however, they can be impacted by drought if the river or dam they draw from is depleted, or is too low to permit the volume of warmed water to re-enter the natural water system. In 2022, the *Jim Bridger coal-fired power plant* in Wyoming was at risk of being shut off as the Green River it draws from ran low.

Closed-loop thermoelectric plants are less affected by drought but draw more water from the system to replenish the amount that evaporates. Dry-cooling plants, which are relatively rare, use the least water, but at the cost of power plant efficiency.

The *Energy Information Administration reports* that thermoelectric plants are becoming more efficient in their water use. "The sector's water-withdrawal intensity — the amount of water withdrawn per unit of electricity generated — continued to fall, declining 2.1% from 11,849 gallons/MWh in 2020 to 11,595 gal/MWh in 2021." Pushing against that trend, the rise in data center energy demand may increase the power sector's total water demand even if the gallons per megawatt-hours declines.

Moving Toward a Lower-water Grid

Of course, the easiest way to reduce the grid's reliance on water is to adopt generation technologies that require little or no water. Solar and wind are obvious candidates, but some types of geothermal and *combined heat and power (CHP)* need little to no water.

Geothermal technologies' water needs vary, with binary cycle power plants' *closed loop systems* not requiring any aside from water used in the initial drilling process. Some of those that use water, such as Fervo Energy, can use *degraded or brackish water* that could not be used for agricultural or other purposes.

CHP systems create efficiencies by capturing the energy from the power plant's steam to provide heating, hot water or chilled water for facilities. They are highly water-efficient, though they're generally limited to smaller power plants co-located with facilities or areas with district heating.

Policy that Prepares for Drought

Regulators, operators and asset owners need to prepare for a drier (and hotter, and wetter, and stormier) future. And that begins with assessing risk.

The West well understands the impact of droughts after the past few years of real-life experience. In other areas, even those that haven't had droughts in the past, modeling potential droughts' impact on reliability and reserve margins is important if the industry is to prepare for the future.

One example: A *study* of the PJM and SERC region's generation capacity found that if the area suffered a drought equal to "the 2007 Southeastern summer drought … the usable capacity of all at-risk power plants may experience a substantial decrease compared to a typical summer, falling within the range of 71 to 81%."

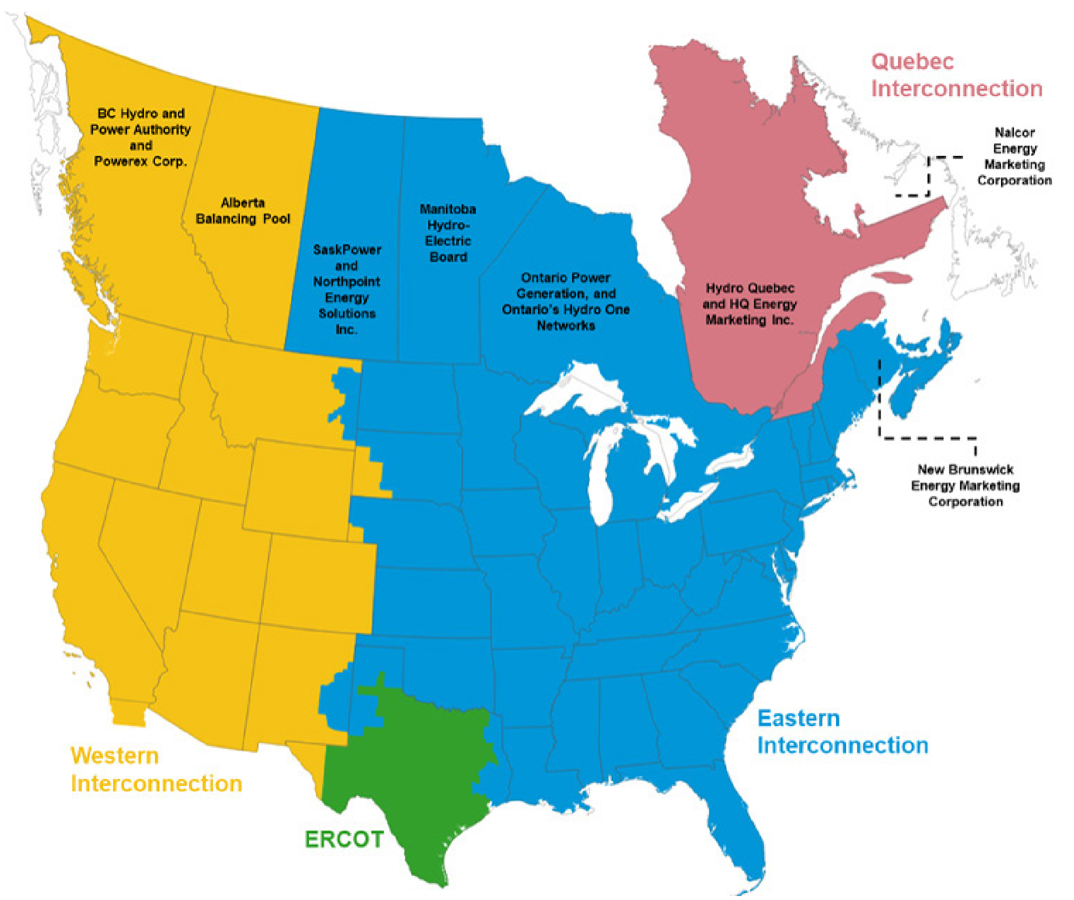
The energy-water nexus must be considered in energy policy and pricing: Low electricity tariffs have made it affordable for farmers to pump scarce groundwater *from aquifers* that do not recharge as quickly as they are being drawn down, especially during periods of drought. And there's untapped potential, pun intended, for incentivizing farmers to pump irrigation and well water at off-peak times or connect automated irrigation pumps to demand-response programs.

The question is whether utilities have any incentive to support policies that will cut the energy used by the water system. Until policies reward water-efficient moves by the energy industry, moving all of that water will continue to consume much of the electricity we produce and keep the industry vulnerable to droughts.

Different Problem; Similar Solution

As with floods, fires and other extreme events exacerbated by climate change, preparing for drought requires building a more flexible and resilient grid. Islandable microgrids, more energy storage, stronger infrastructure and diversified generation sources all help stabilize the grid, whether facing a long-duration challenge like a drought or an immediate emergency like a flood.

Extreme weather events require thinking, and collaborating, outside the electric box: No single industry can prepare alone, and the sooner that states and regions put together integrated plans for these climate extremes that include all of the energy system players along with those in charge of water, transportation and every other piece of critical infrastructure, the better able we'll be to cope with the next extreme weather event. ■



Drought impacts U.S. and Canada's energy trade. Normally, Canada is a net exporter because of its strong hydro sector, but a drought changed the direction of the electric flow as Canada's generation fell. | *EIA*

ERCOT Generation Netting Isn't Yet Investment Grade for Renewable Firmed Data Centers

Where Protocol 10.3.2.3 Helps, Where it Stops and What 'Netting Plus' Needs to Standardize

By Alexandre Alonso Carpintero

Alexandre Alonso Carpintero

ERCOT is absorbing a wave of large, price-sensitive load, especially data centers, faster than the market rules were built to "productize."

ERCOT planning materials show about 226 GW of large loads seeking interconnection as of Nov. 18, 2025 (up from 63 GW in December 2024), with about 225 new large-load requests submitted in 2025 and about 73% of the queue *attributed to data centers*. If the finance path for renewable-firmed supply is uncertain, the default "under-writeable" answer becomes on-site gas.

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What Generation Netting Really is

Generation netting for ERCOT-polled settlement (EPS) meters (Protocol 10.3.2.3) is a settlement boundary rule: Under specific electrical configurations and metering constraints, ERCOT may settle a paired generator and load on a net basis. The protocol is intentionally restrictive ("generation netting is not allowed except under" *defined conditions*) and depends on site topology (e.g., common switchyard concepts, EPS metering points and limits on alternate grid connections). Netting can reduce settled energy volume. It does not convert a complex behind-the-meter campus into a financeable product. (See *Aurora Research Report*.)

Why it Fails the 'Investment-grade' Test

Credit committees don't finance "net megawatt-hours." They finance the residual risk stack, especially correlated tail risk. Even with netting, a renewable-firmed data center typically retains:

- *scarcity price tail on backup imports*. ERCOT's systemwide offer cap (HCAP/SWOC) remains $5,000/MWh (with a low cap framework that can apply under certain conditions).
- congestion/basis risk (nodal price separation between where supply is produced and where load settles).
- operational/curtailment risk: The usable "firming" value of renewables plus storage can degrade precisely when the grid is stressed (telemetry/dispatch constraints, emergency operating modes or required load shedding).
- administrative/process risk: eligibility, metering design and true-ups can become bespoke legal/settlement work, hard to replicate across multiple campuses.

SB 6 Adds Layer of Uncertainty

Texas SB 6 (effective June 20, 2025) added PURA section 39.169, requiring system-impact review of certain net-metering arrangements involving new large loads and standalone generation. ERCOT's market notice *M-B090225-01* implements interim procedures, publishes a list of standalone generation resources (as of Sept. 1, 2025) and states the process may change or be pre-empted by forthcoming Public Utility Commission of Texas rules.

ERCOT's large-load interconnection Q&A further notes that some arrangements involving existing "standalone" resources require approval through the *net metering review* process before the load can be energized. "Interim and subject to change" is not bankable language when you're trying to finance repeatable, gigawatt-scale campuses.

A Simplified 300-MW Hybrid Example (Wind + Solar + BESS)

Assume a 300-MW flat-load campus behind EPS metering with 300 MW of wind plus 300 MW of solar plus a 100-MW, 400-MWh (four-hour) battery. Netting can reduce settled imports across many hours. The financing problem is the tail.

Illustrative stress case: 20 scarcity hours per year when renewables are low and the battery is depleted or held for contingency. If the campus must import 100 MW during those hours and real-time prices clear at $5,000/MWh, the annual cost is: 20 h × 100 MW × $5,000/MWh = $10 million.

That volatility is correlated with grid

Risk	Why it remains after netting
Scarcity price tail	Backup imports still clear at real-time nodal prices up to the offer cap framework.
Congestion / basis	Price separation persists across nodes/constraints and between portfolio and settlement node.
Operating mode / curtailment	Emergency rules and telemetry/dispatch constraints can reduce usable output at critical hours.
Rule/process risk	Eligibility, metering design, and Net Metering Review steps can change and are often bespoke.

Residual risk stack after Generation Netting | *Alexandre Alonso Carpintero*

stress and uptime risk. The easiest way to cap both is a 300-MW on-site gas plant, hence gas becoming the "insurance policy" for load growth.

What 'Netting Plus' Should Standardize

ERCOT does not need to copy another RTO. It needs standardized pathways that turn behind-the-meter engineering into predictable settlement plus performance rules:

- campus netting: standardized netting across a defined private network footprint (multiple meters/feeders under common control) with clear telemetry and true-up rules.
- measurable firmness: a standardized add-on (e.g., a performance obligation or ancillary-service bundle) that lets large loads pair renewables with qualifying firming (storage, fast response, contracted curtailment) and get settleable credit.
- clear hybrid "serve-load-first" rules: reduce ambiguity for storage charging/discharging, exports and when the site is acting as load vs. generation.
- transparent backup settlement: make residual grid exposure bounded and hedge-able rather than a surprise.

Protocol 10.3.2.3 is a starting point. "Netting plus" is what makes renewable-firmed data centers financeable at scale. ■

Alexandre Alonso Carpintero works on market design and commercial structures for large loads, including data centers.

Where are Utilities Best Serving Customers?

By Alison Williams

Alison Williams | *Power for Tomorrow*

PJM had a big day Jan. 16.

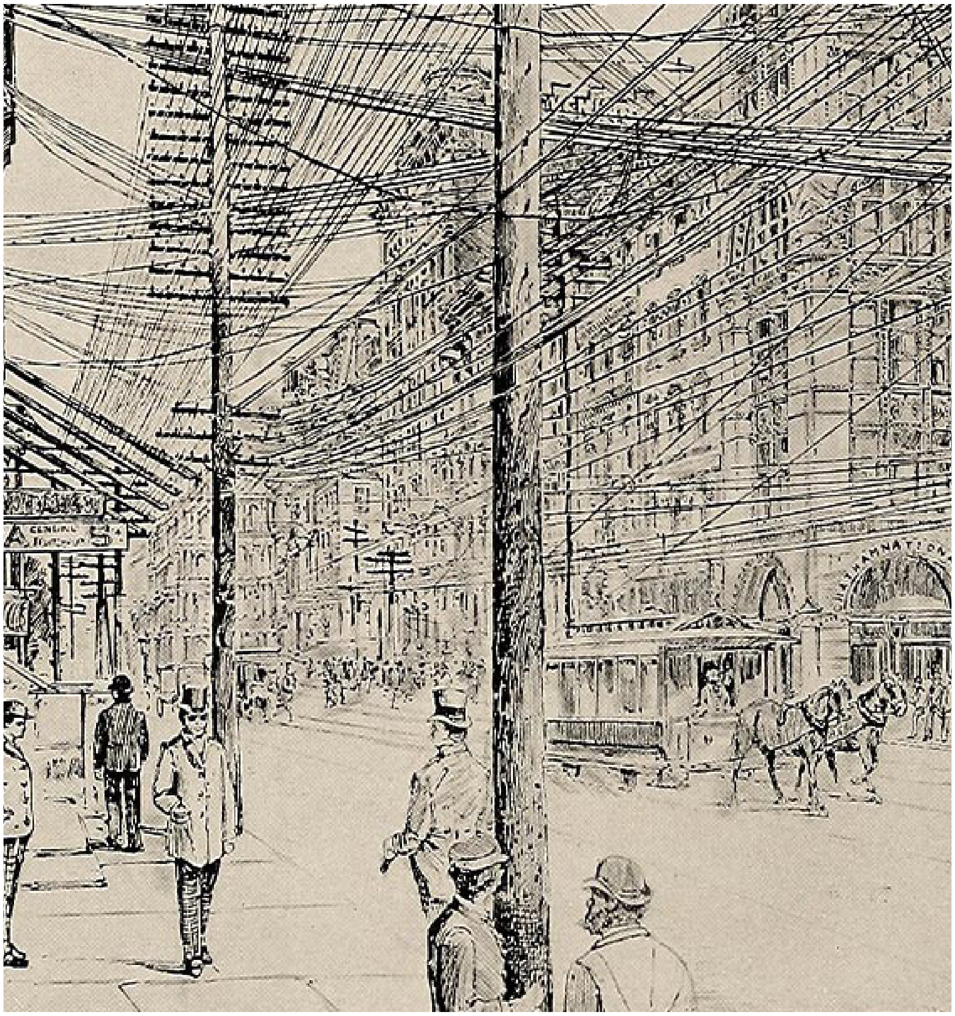
The governors of states in the RTO's territory met at the White House to discuss the flailing market; the administration's Energy Dominance Council released a fact sheet on bringing big power plants back to solve PJM's generation problems and a statement of principles urging it to make tariff revisions to right the ship; and the RTO's Board of Managers released a letter directing its staff to make operational and market modifications, including revising its methods of load forecasting, instituting a reliability auction and forming a Bring Your Own New Generation (BYONG) plan for large load customers.

The series of overlapping and likely coordinated actions has been received well by the energy community. And yet, what are being proposed are merely ideas. As Commissioner David LaCerte commented at FERC's open meeting Jan 22: "These issues raised in these announcements will make their way to FERC soon." Translation: We're still talking about solving problems, not actually solving them.

So if we're still in the planning phase, policymakers would be wise to look beyond PJM to find successful examples of the mutually beneficial outcomes everyone wants: American energy dominance, industrial competitiveness and customer protection.

Vertically integrated utilities have been doing this successfully for more than a century. In regions like the Southeast, this electric industry structure — where utilities own generation, transmission and distribution — is shielding customers from price spikes while supporting economic growth.

The data overwhelmingly support the vertically integrated model. On average, based on 2024 prices, residential customers in "deregulated" states paid 42% more for electricity than residential customers in states with vertically integrated utilities. Excluding Alaska and Hawaii — outlier states with unique geographic considerations — eight of the 10 most expensive states for electricity have a "competitive" structure.



Hundreds of utility lines crisscross a New York City thoroughfare in this circa 1890 drawing. The chaotic tangle of wires serving individual homes and businesses eventually prompted business model and regulatory reforms, leading to the consolidation of competing electric companies into Consolidated Edison in 1936. | *Public Domain via Wikimedia Commons*

Competition's promise was lower prices, right? The hard data show that this promise has failed, costing residential customers billions. For example, in Illinois, a national consumer group has found that electric customers have paid $2 billion more for electric "choice" than they would have with the default utility.

The success of the vertically integrated utility isn't by chance. And it isn't monopoly power run amok. Rather, the vertically integrated utility model exists to serve the public interest and place the customer front and center. When Congress passed the Federal Power Act, it chose this approach because electricity requires massive infrastructure investment and therefore demands a different framework. We don't need to imagine what thousands of wires individually bringing power to homes would look like because we see that in some parts of the world, and that is the way power was delivered in New York City in the late 19th century.

The primary operating principle of the vertically integrated utility is an obligation to serve all customers. These utilities are required to conduct extensive long-term planning where supply and demand must be balanced over decades and the procurement of resources must be the best combination of least cost and least risk. None of these actions or plans can move forward without oversight and approval by state regulators, who hold the dual objectives of supporting state-based growth and ensuring electric rates are fair, reflect actual costs and are allocated fairly across all customers. This relationship between utilities and their regulators is the original public-private partnership — and it doesn't just work for electricity; it's also a successful model for water, sewer and gas heating.

Yet, despite a century of success and recent data affirming that customers win under the vertically integrated model, some believers in "competition" continue to make the case for expanding it throughout the electric sector, including pushing for open solicitations for transmission projects. But the data are clear there too, and the pattern repeats: "Competitive" transmission delivers the same disappointing results as "competitive" electricity markets.

Consider what "competitive transmission" actually means. Planning entities determine which transmission projects are needed before any competition begins. Developers (the ones supposedly competing) merely bid to see who builds projects, not on identifying needs or providing ongoing competitive service. Indeed, competitive transmission operators have been fighting for years to be treated like regulated utilities when it comes to prices. Moreover, their so-called competitive bids routinely fail to translate into actual customer savings, proving the theory wrong.

A revealing example comes from New York in 2022, where a "competitive" bid came in 22% lower than the local utility's proposal. Advocates of competitive transmission celebrated this as proof that competition in transmission can work. But the developer encountered cost overruns of about $74 million above its cost cap because of regulatory delays, transmission line rerouting, tree clearing and wetland mitigation. Tellingly, the original bid failed to account for these costs — whether through strategic omission to win the contract or unfamiliarity with local terrain and regulatory requirements. Ultimately, this project's cost reached $249 million, up 38% from the winning bid and exceeding what the experienced local utility would have charged.

These stark examples of "competition" failures are particularly important now, as many state legislative sessions resumed at the start of the year and legislators are feeling pressure to find solutions to rising energy costs. Perennial bill proposals on energy often include doubling down on market structures, deregulation and pushes for retail or industrial "choice." But these options can be best described as "competition for competition's sake."

Today's policymakers should ask a simpler question for finding energy solutions: "What approach best serves customers?" The answer is clear: Well-regulated, vertically integrated utilities have a proven track record of protecting customers.

Electric utilities overseen by smart regulators provide the actual benefits that "competition" is supposed to deliver — downward pressure on prices, accountability for performance and incentives for efficiency — but with additional protections that markets cannot provide, including mandatory service obligations, reliability requirements, and protection from price volatility and market manipulation.

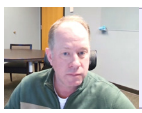
Regulators disallow cost recovery for imprudent investments, enforce lowest reasonable cost standards, and ensure balanced consideration of customer and shareholder interests. These are not theoretical benefits; they are demonstrated outcomes from a century of sound regulatory practice. We have examples of success popping up across the country, where vertically integrated utilities are recruiting data centers and advanced manufacturing with fair electricity rates that don't harm small customers and average citizens.

The choice facing policymakers is straightforward: proven regulatory approaches that prioritize customers, or continued experimentation with "competitive models" that have repeatedly failed to deliver on their promises. After a century of evidence and recent high-profile market failures, the answer should be clear. ■

Alison Williams is senior vice president of Power for Tomorrow*, a nonprofit that provides practical research, commentary and information regarding how the regulated electric utility model protects consumers and promotes consumer benefits.*

National/Federal news from our other channels

NERC Modernization Task Force Leaders Present Final Recommendations — ERO Insider



NERC SC Kicks off 2026 with Organizational, Standards Items — ERO Insider

NERC Managers Share 2026 Priorities — ERO Insider

Stakeholders Support Adopting NAESB Standards — ERO Insider

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Power Grids Weather Winter Storm Fern, Face Continued Cold Snap

By James Downing

The winter storm that moved through Texas and much of the Eastern Interconnection over the Jan. 24-25 weekend cut power to hundreds of thousands of people and stressed the bulk power system, but it did not create major disruptions like storms earlier in this decade.

The storm dumped snow, sleet and freezing rain across its path, with the most power outages occurring on its southern edge — especially in the lower Mississippi Valley, according to the National Weather Service. Entergy Louisiana said Jan. 26 that most customers who lost power in its territory would be restored by Jan. 28, with some repairs taking a day longer.

NYISO wholesale power prices briefly hit quadruple digits around 11 p.m. ET on Jan. 25 (Sunday), while the Dominion Zone in PJM saw prices above $1,000/MWh for much of the day.

PJM is actually expecting higher demand Jan. 27, with lower temperatures prompting it to issue a maximum generation *alert* and a low voltage *alert*. The RTO could break its winter peak record that day, as it forecasts peak demand of 147.2 GW, which would beat the mark of 143.7 GW set a year ago.

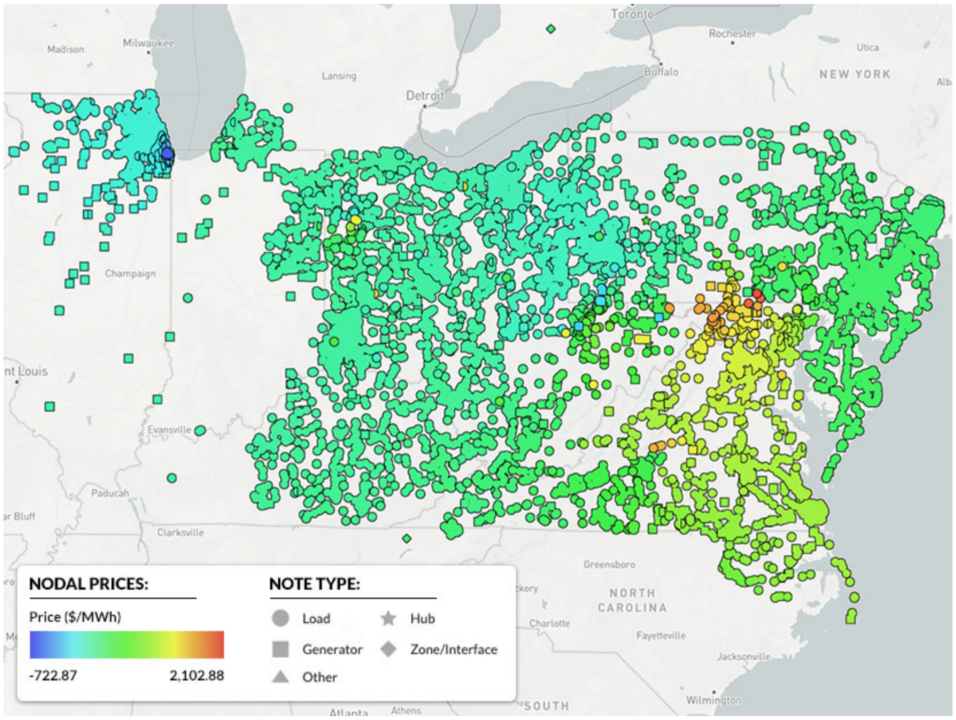
The RTO said that it could see peak demand hit 130 GW for seven straight days, which would be a first for winter.

"This is a formidable arctic cold front coming our way, and it will impact our neighboring systems as much as it affects PJM," Senior Vice President of Operations Mike Bryson said in a statement. "We will be relying on our generation fleet to perform as well as they did during last year's record winter peak."

PJM was one of *several* grid operators to take up the Department of Energy on its offer to issue emergency orders under Section 202(c) of the Federal Power Act. (See *Wright Ready to Use Emergency Powers to Dispatch Backup Generation During Storm*.)

PJM asked DOE to issue a 202(c) order to allow it to dispatch every generator in its footprint at is maximum level without violating air quality laws — an order that remains in place through the end of January.

DOE issued a similar order to ISO-NE as New England deals with the same cold.



A map produced by Yes Energy showing LMPs in PJM when the storm was its peak on Sunday. | *Yes Energy*

Why This Matters

The winter storm and related cold snap are giving the bulk power system its first test of 2026 as prices shot up in many markets and hundreds of thousands lost power due to distribution outages.

One generator informed ISO-NE that it was running up against its permitted emission limits.

"This prolonged severe cold weather event is expected to result in a sustained high level of demand for electricity," ISO-NE told DOE in its order application. "While the vast majority of generating units in the ISO-NE region continue to function adequately, some units may experience difficulty due to emissions/air permitting limitations or other operating constraints."

NYISO is facing the same winter weather as its two neighbors, announcing last week that it could see peak demand exceed 24 GW, which was near expectations for this winter, but falls short of its all-time winter peak of 25.7 GW set in 2014.

"Our assessment finds there are adequate resources to serve demand on the grid under forecast conditions, but we've also seen generators in recent winters challenged with accessing adequate fuel capacity during very cold conditions," NYISO Vice President of Operations Aaron Markham said in a statement.

MISO also issued a *cold weather alert* that remains in place through the end of January as low temperatures impact its footprint. It also issued a conservative operations *declaration* covering the cold snap.

MISO saw prices peak at about $1,802/MWh on Jan. 23, although they averaged just $178.04 across its entire footprint, while prices were slightly lower by Jan. 25.

SPP Back to Normal Conditions

SPP had returned to normal operating conditions as of 12 p.m. CT Jan. 26, after expiration of conservative operations and resource advisories that were in effect during the storm. However, it extended its weather advisory — considered normal operations — through noon Jan. 28 to maintain awareness of potential weather-related effects on system resources.

A spokesperson said the RTO had sufficient generation and met reserve obligations in its 14-state footprint during the storm, with load reaching about 46 GW during the morning peak Jan. 26. Load is forecasted to remain in the mid-40-GW range through the remainder of the week. SPP's winter peak record of 48.1 GW was set in February 2025.

"We did not experience any major transmission losses, but we did get reports of local outages, particularly in the southern portion of our footprint," SPP's Derek Wingfield said.

He said the grid operator remained in close coordination with neighboring systems throughout the event, providing energy exports as needed and as available generating capacity allowed.

"We will continue to monitor conditions closely and will issue additional advisories as necessary," Wingfield said.

Stronger ERCOT Grid Performs

The ERCOT grid breezed through the storm, a marked contrast to the dayslong outages during the disastrous February 2021 Winter Storm Uri. Since then, winterization has become mandatory for power plants and critical natural gas infrastructure. ERCOT has also added about 40 GW of capacity since the 2021 storm to bulk up its energy supplies.

About 90% of the new generation added since 2021 has been wind, solar and battery storage. Batteries provided more than 7 GW of energy at 8 a.m. CT Jan. 26. ERCOT's instant storage discharge record stands at 9.7 GW, set in December 2025.

Natural gas provided more than 50.8 GW of energy at one point Jan. 26, another record, according to *Grid Status*.

This comes after DOE granted ERCOT's request for an emergency order under the FPA because of the storm. The order allows certain electric generating units to operate up to their maximum generation output in certain limited circumstances, despite federal or state environmental standards and requirements.

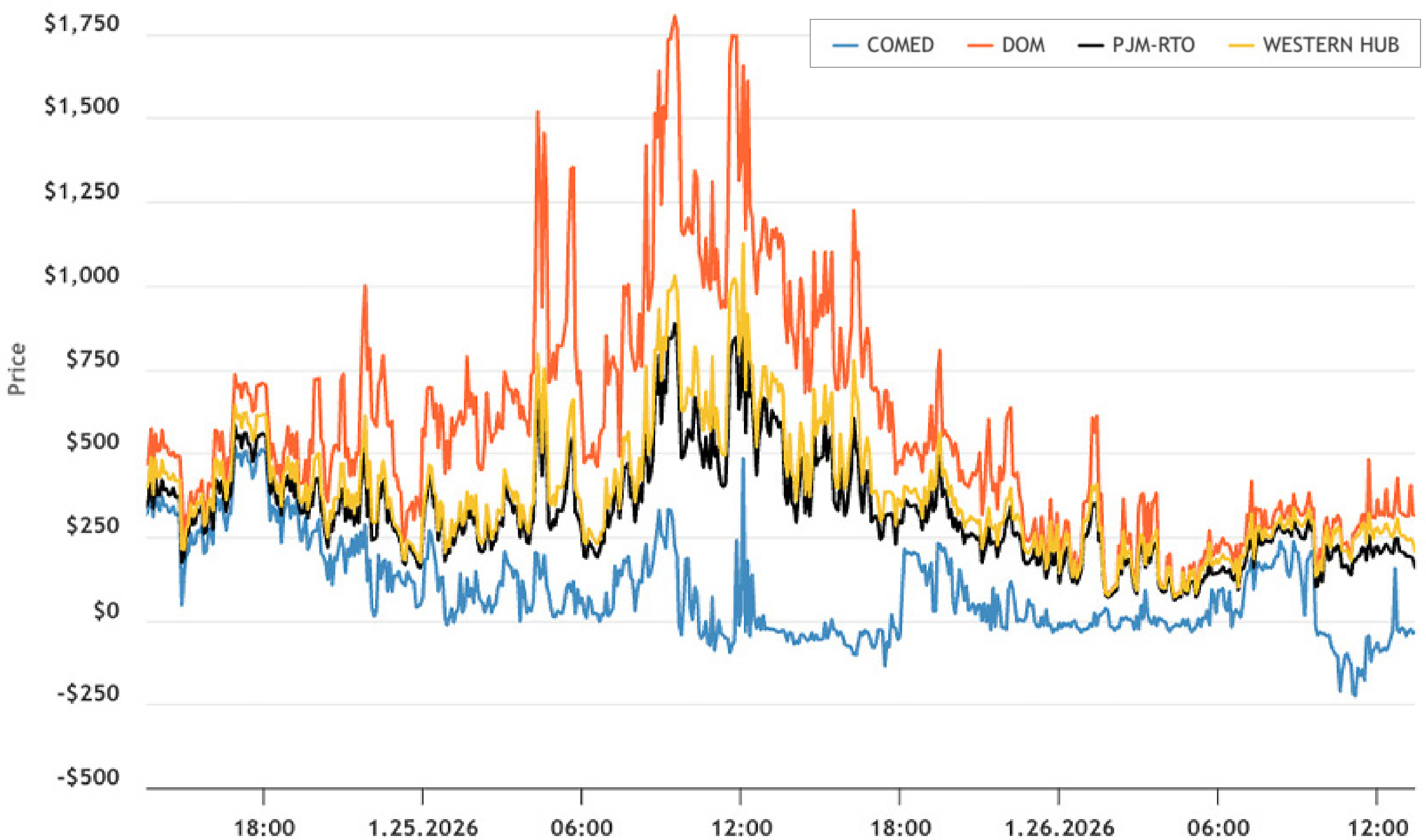
The order is effective until 11:59 p.m. Jan. 27.

Early demand projections of 83 GW failed to materialize. Demand is now expected to peak around 78 GW on Jan. 27.

ERCOT did declare a transmission emergency late Jan. 25 because of the loss of generation and transmission-line issues in the San Antonio and Houston areas. The emergency was canceled during the morning hours Jan. 26.

ISO staff have also canceled the operating condition notice (OCN) issued ahead of the approaching cold weather system. OCNs are the first of ERCOT's "four levels of communication issued in anticipation of a possible emergency condition" and are issued when the system's safety or reliability is compromised or threatened.

More than 61,000 Texas customers were out of power as of noon Jan. 26, primarily in the northeastern region of the state where American Electric Power subsidiary Southwestern Electric Power Co. and Entergy Texas operate. ■



A graph from PJM's Data Viewer showing real time prices by different zones as the storm passed through its territory. Dominion saw the highest prices. | *PJM*

DOE to Restructure or Eliminate $83 Billion in Biden-era Loans

By James Downing

Why This Matters

DOE's move is sure to deliver another blow to renewable energy developers and states' plans to reduce carbon emissions.

The U.S. Department of Energy said it is restructuring, revising or eliminating more than $83 billion in loans and conditional commitments issued under the Biden administration.

The Loan Programs Office offered a total of $104 billion under President Joe Biden, much of which came from the Inflation Reduction Act, the 2022 law that was passed using reconciliation to get around Republican filibusters in the Senate. President Donald Trump's DOE lambasted the loans as part of the "Green New Scam" and has transformed the loans office into the "Office of Energy Dominance Financing."

"Over the past year, the Energy Department individually reviewed our entire loan portfolio to ensure the responsible investment of taxpayer dollars," Secretary Chris Wright said in a Jan. 22 *statement* announcing the move. "We found more dollars were rushed out the door of the Loan Programs Office in the final months of the Biden administration than had been disbursed in over 15 years. President Trump promised to protect taxpayer dollars and expand America's supply of affordable, reliable and secure energy."

DOE has eliminated $9.5 billion in funding that was going to wind and solar, replacing it with investments in natural gas and uprates at nuclear power plants.

Of the $104 billion in Biden administration loan obligations, DOE has withdrawn or is in the process of de-obligating nearly $30 billion, with an additional $53 billion in revision.

The new Office of Energy Dominance Financing has more than $289 billion in available loan authority, which is accessible to more types of projects after the One Big Beautiful Bill Act. The funding level makes it the biggest energy lender in the world, DOE said.

The office is targeting six sectors: nuclear, fossil fuels, critical minerals, geothermal, the electric grid, and manufacturing and transportation, according to a *blog post* by its senior adviser, Gregory Beard.

The office closed three loans toward the end of 2025 totaling $4.1 billion, including a loan to Constellation Energy to restart the Three Mile Island nuclear plant; one to an American Electric Power subsidiary to strengthen its transmission system; and another to Wabash Valley Resources to use a coal plant to produce fertilizer.

This year the office will prioritize projects that contribute to energy security, grid reliability and affordability, Beard wrote. ■

The Forrestal Building in D.C., home of the U.S. Department of Energy | *DOE*

Report Quantifies Climate, Health Benefits of Clean Energy for Data Centers

Union of Concerned Scientists Urges Policymakers to Protect Ratepayers, Planet

By John Cropley

The latest in a series of Union of Concerned Scientists (UCS) reports on the costs of the AI boom asserts that powering U.S. data centers with clean energy would avert trillions of dollars in health and environmental costs.

The report, issued Jan. 21, warns about the public potentially paying twice for the massive data center buildout many observers expect — first to cover the cost of new grid infrastructure, then a second time for the negative impacts of that infrastructure if it relies heavily on fossil fuels.

"Overall, our modeling demonstrates that clean and renewable energy can meet the challenge of load growth from data centers, but policymakers must be proactive to protect our health, environment and financial interests," Director of Energy Research and Analysis Steve Clemmer *said in a news release* announcing the study.

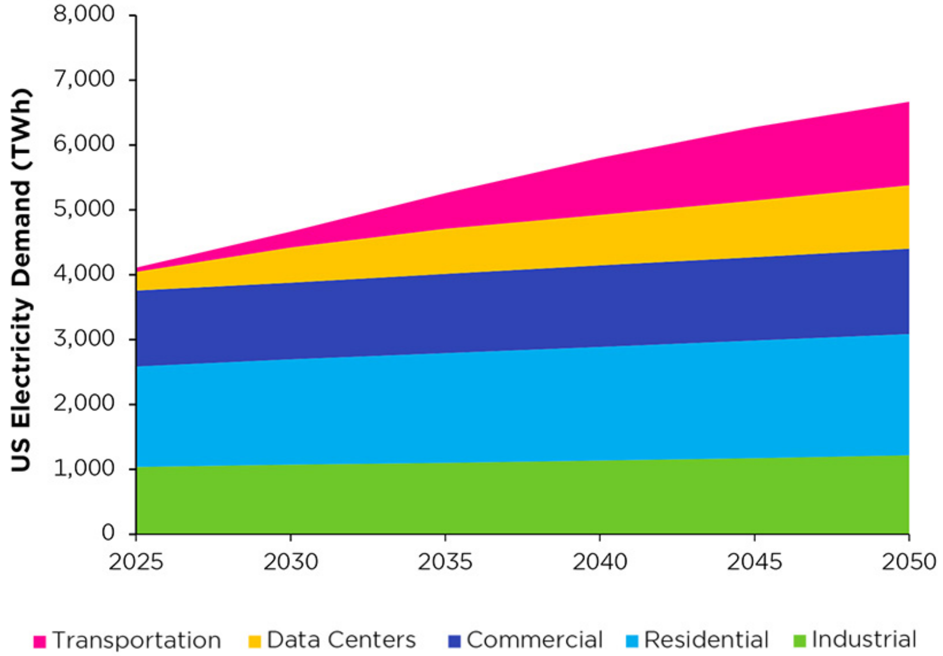
"Data Center Power Play: How Clean Energy Can Meet Rising Electricity Demand While Delivering Climate and Health Benefits" does not present green power generation as a direct cost savings — decarbonizing the power sector would instead increase U.S. wholesale electricity costs $412 billion or 7%, it says.

Restoring federal clean energy tax credits to the levels in the Inflation Reduction Act would shift the cost off ratepayers and lower electricity costs by $248 billion or 4%, the authors write.

Both figures would be dwarfed by the $8 trillion to $13 trillion in cumulative global climate benefits and the $120 billion to $220 billion in cumulative health benefits

Why This Matters

The report is an attempt to quantify the costs and impacts of power grid updates to power a tsunami of data center development.



A new study by the Union of Concerned Scientists projects data centers would increase from 4.4% of total U.S. power consumption in 2023 to 11.6% in 2030 and 15% in 2050 in a middle demand growth scenario. | *Union of Concerned Scientists*

expected to result from decarbonization by 2050, the authors write.

That is a tradeoff the present team of federal policymakers appear unlikely to make, but the report also calls for state policymakers to take action to avoid financial, health and environmental impacts harms associated with unchecked growth of data centers.

The analysis looks at three scenarios: the current policy landscape created by the Trump administration and its allies in Congress; restoration of electricity tax credit provisions of the IRA; and a national effort to reduce the power sector's carbon dioxide emissions 95% by 2050. It uses a midlevel assumption for data center demand growth but adds a no-demand growth comparison to isolate the impacts of data centers.

The study estimates that:

- Data center demand could increase from 31 GW in 2023 to 78 GW in 2030 and 140 GW in 2050.
- More than 90 GW of new gas-fired capacity would be added by 2035 and 335 GW by 2050 under Trump administration policies.
- Coal-fired generation as a percentage of the whole would decrease by 2035 and 2050 under all three scenarios.

Illinois, Michigan, Wisconsin

The report is accompanied by a *technical appendix*, as well as breakouts drilling down on projected impacts in three Upper Midwest states.

"Looking collectively at our findings for *Illinois*, *Michigan* and *Wisconsin*, it's clear that strong, foundational state clean energy policies are helpful for confronting the large — yet highly uncertain — data center-driven growth in electricity demand," *said James Gignac*, UCS Midwest policy director. "But without careful, specific attention by state policymakers and regulators to data centers, the rapid rise in the need for power leads to increased costs and pollution."

UCS noted Illinois has strong power sector decarbonization policies but said more is needed, because without further policy protections, data center-driven load growth could put Illinois at risk of $24 billion to $37 billion in additional electricity system costs.

It said data centers could account for up to 72% of electricity demand growth in the state by 2030. But current policies will increase the use of in-state fossil fuel plants and increase reliance on out-of-state generation, UCS said.

Michigan too has enacted significant clean energy legislation in the 2020s, UCS said, but lawmakers left a loophole: The restrictions apply only to electricity sold within the state, not to energy generated in-state but exported to other states.

UCS recommended that Michigan close that loophole.

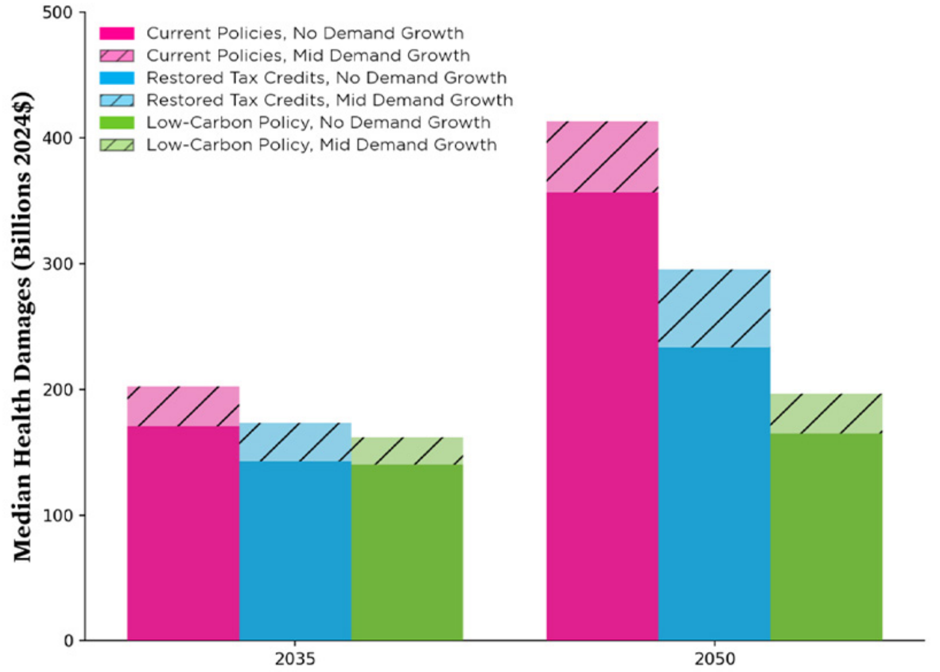
It also said Michigan's electricity demand could nearly double by 2050, with data centers accounting for up to 38% of the increase, but said those estimates were highly speculative. It called for greater transparency from data center developers and flexible utility planning.

UCS said Wisconsin does not have comprehensive clean energy policies in place but is experiencing a data center development boom. Current policies would prompt large increases in natural gas generation with accompanying increases in carbon emissions.

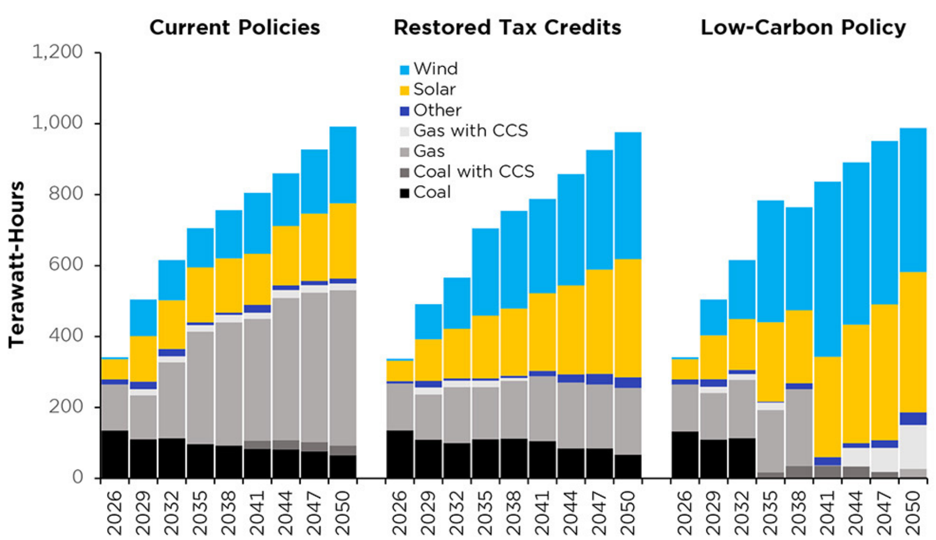
UCS recommended that Wisconsin commit to clean energy policies now; adopt ratepayer protections that require data centers to bring their own clean energy generation; be transparent about decision making; and impose integrated resource planning requirements on utilities.

It did note movement in Wisconsin's statehouse in 2025 on measures intended to reduce economywide carbon emissions and protect consumers from the costs and carbon emissions of new data centers.

As of 2023, coal- and natural gas-fired power plants provided 75% of Wisconsin's in-state generation, UCS said.



Data centers' impact on I.S. health care costs is projected in 2035 and 2050 under different growth and policy scenarios. | *Union of Concerned Scientists*



The generation technology mix expected to power U.S. data centers is shown under three policy scenarios. | *Union of Concerned Scientists*

Methodology

The UCS analysis uses the *Regional Energy Deployment System*, a least-cost electricity planning and dispatch model developed by what was then known as the National Renewable Energy Laboratory, and it relies on electricity demand projections developed by Evolved Energy Research for its *Annual Decarbonization Perspective 2024* report.

The concept of flexible data center demand — recently gaining much attention as a means of reducing peak load and reducing the need for new infrastructure — was not included in the analysis, nor were impacts of recent market and policy changes, such as new tariffs, rising gas turbine costs, natural gas price volatility and federal road blocks to renewable power development.

New nuclear capacity — another priority of the Trump administration — was not modeled because of its high cost. Also not modeled was Big Tech's interest in paying above-market prices to restart or uprate existing nuclear plants, or in building new reactors to power data centers.

Finally, the authors note that the number of data centers to be built and the amount of electricity they will consume are both highly uncertain. Also unknown are technology advances that may change the energy profile of future data centers. ■

Could the U.K.'s Cap-and-Floor Model Unlock Interregional Transmission in the U.S.?

By James Downing

Why This Matters

While interregional transmission promises reliability and economic benefits, getting it built is difficult and the revenue cap-and-floor the U.K. uses for similar lines could make financing easier and address cost allocation.

Setting up cost floors and caps for transmission lines can help get major transmission connections between markets built, experts said in a webinar hosted by the American Council on Renewable Energy (ACORE) on Jan. 20.

The U.K. has used that method to finance major new interconnectors with different markets on the European mainland and Ireland, and advocates said it could help get interregional lines financed and built in the U.S.

Using floors and caps for major transmission lines combines the investment certainty from regulated rates and merchant exposure that optimizes asset use, said Regulatory Assistance Project Principal Jennifer Chen.

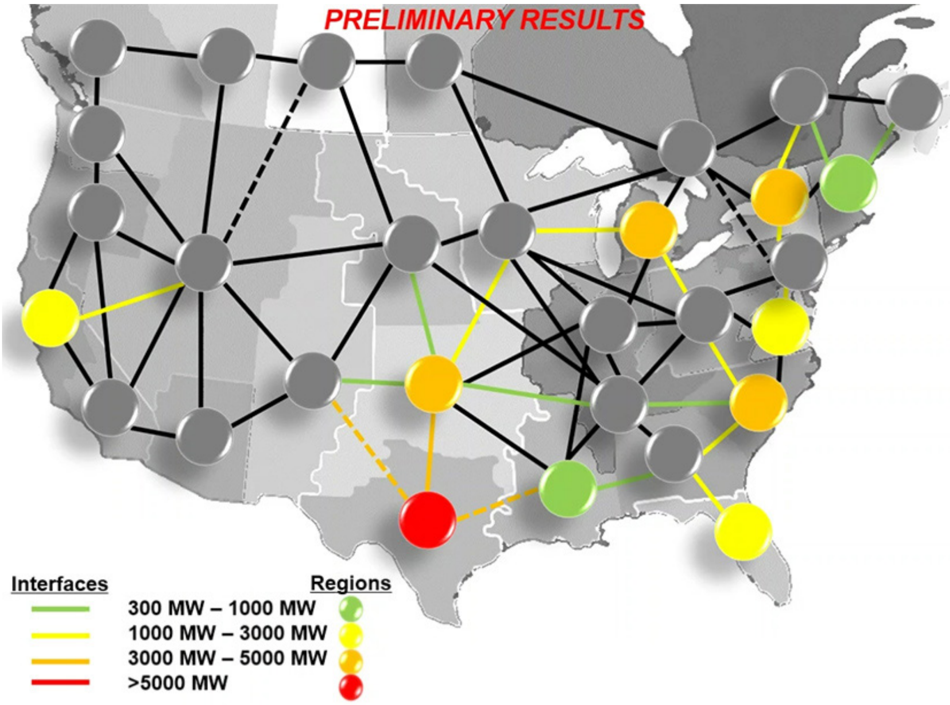
"Regulated interregional transmission is challenging because balkanized planning and disagreements between neighboring authorities on shared costs borne by their respective captive ratepayers can present issues," Chen said. "On the other hand, purely merchant financing faces challenges with upfront investment and certainty, amongst other issues."

Cap-and-floor is a financing model that combines approaches from both with the floor offering certainty and the cap allowing trading potential to be maximized. Customers get paid back if revenue exceeds the cap over a set period, and the floor requires ratebase customers to pay to meet it when market revenues fall short.

"Projects can create more value than in a purely regulated setting. That value can be shared with customers," Chen said. "The costs of the projects are allocated to the markets, to those procuring transmission services, instead of defaulting to captive ratepayers."

Since being implemented in 2014, the method has led to several major transmission links between Great Britain and other countries. Great Britain is regulated by the Office of Gas and Electricity Markets (Ofgem), while National Grid runs the transmission system for England and Wales.

Regulators have issued several solicitation windows since 2014 and picked projects that produced net benefits and filled a need on Great Britain's grid.



The preliminary results of NERC's ITCS study show where it would make the most sense to build interregional transmission capacity. Using a price floor and price cap could help get these lines built, experts said on ACORE's webinar. | *NERC*

"The first interconnectors in Great Britain were developed under a merchant model where revenues were fully exposed to market risks and developers would seek exemptions from certain regulatory requirements," said Ofgem's Megan Jones.

Then, in 2007, the European Commission put a cap on revenue for an interconnector between Great Britain and the Netherlands called "BritNed."

"Because of this decision to impose this additional condition, there was a risk that the merchant model, and therefore interconnected development more broadly, could become less attractive to investors and developers," Jones said.

Working with regulators in Belgium, Ofgem introduced the cap-and-floor model in 2014 to make merchant interconnectors viable again.

"Developers are incentivized to invest in a project where the potential market value of an interconnector and the consequent revenues are greatest compared with their costs," Jones said. "This means that there is also an incentive for developers to keep delivery and operation costs down."

Those incentives minimize the risk that consumers will have to pay anything to ensure interconnectors' revenue meets the floor price, she added.

Ofgem has open three solicitation

windows so far in 2014, 2016 and 2022. Before then, Great Britain had four connections with neighboring countries, and since then, four more have been completed, one is under construction, and seven more have won regulatory approval, Jones said. They have created 5.3 GW of transfer capacity and see flows go both ways, though for now, Great Britain is a net importer.

"Various projects have returned revenues above the cap to consumers, and at the moment, that currently amounts to roughly 300 million pounds having been returned," Jones said.

National Grid has participated in those solicitations through its subsidiary National Grid Ventures, said the latter's Mark Tunney. It's still possible to build interconnectors without the cap-and-floor model, but those projects are much rarer.

"We submit all of our various parameters into Ofgem in order to assess the cap and the floor," Tunney said. "So, what is the capital cost we spent? What are the 'OPEX' costs that we anticipate? Our tax, the allowed return, is calculated by Ofgem, etc. And they form the cap and the floor."

The revenues are measured against the cap and the floor every five years for the lines National Grid has constructed, but Tunney said that could be cut down to one year to work better with different business models.

After the lines get built, Ofgem does an audit of the construction process and its costs, and Tunney said National Grid Ventures has gotten somewhere between 97 and 99% of its project costs approved for the floor under that process. Ofgem also allows changes in the floor-and-cap parameters over the project's life if rules and regulations change that require more spending, he added.

Grid United develops interregional transmission lines in the U.S. that operate like the interconnectors across the Atlantic, and has been interested in using the cap-and-floor model since learning about it several years ago, said CEO Michael Skelly.

"We have talked to a number of policymakers here in the U.S. about this idea, and I think there's some real interest out there," Skelly said. "We would need to build momentum and so on. But the reasons that we're enthusiastic overall because it may help us cut through the Gordian knot that we have here in the U.S. — how are we going to pay for new transmission?"

Grid United has done some calculations on different projects and found that the cap-and-floor method could lower revenue requirements for major transmissions by 30 to 40%, he added.

But getting the method in place will require some outreach to regulators so they understand how it works and, given the political climate here, the concept could use a rebrand.

"We'll have to come up with a new name here in the U.S. because people might think this is some carbon thing, which we may have a hard time to sell," Skelly said. "But there's lots of clever people out there that can figure out how to sell it." ■

EVs Outrank Data Centers in California Electricity Demand Forecast

2025 IEPR Forecast will not Include IOUs' 'Known Loads'

By Robert Mullin

The California Energy Commission has signed off on a forecast showing the state's electricity consumption could surge by as much as 61% over the next 20 years, but it pegs the biggest driver as increased electric vehicle use, with new data centers coming in second.

The CEC on Jan. 21 voted to approve a resolution adopting the forecast and including it in the agency's 2025 Integrated Energy Policy Report (IEPR), which informs the state's resource adequacy requirements, integrated resource plans, reliability assessments, and transmission and distribution planning.

Why This Matters

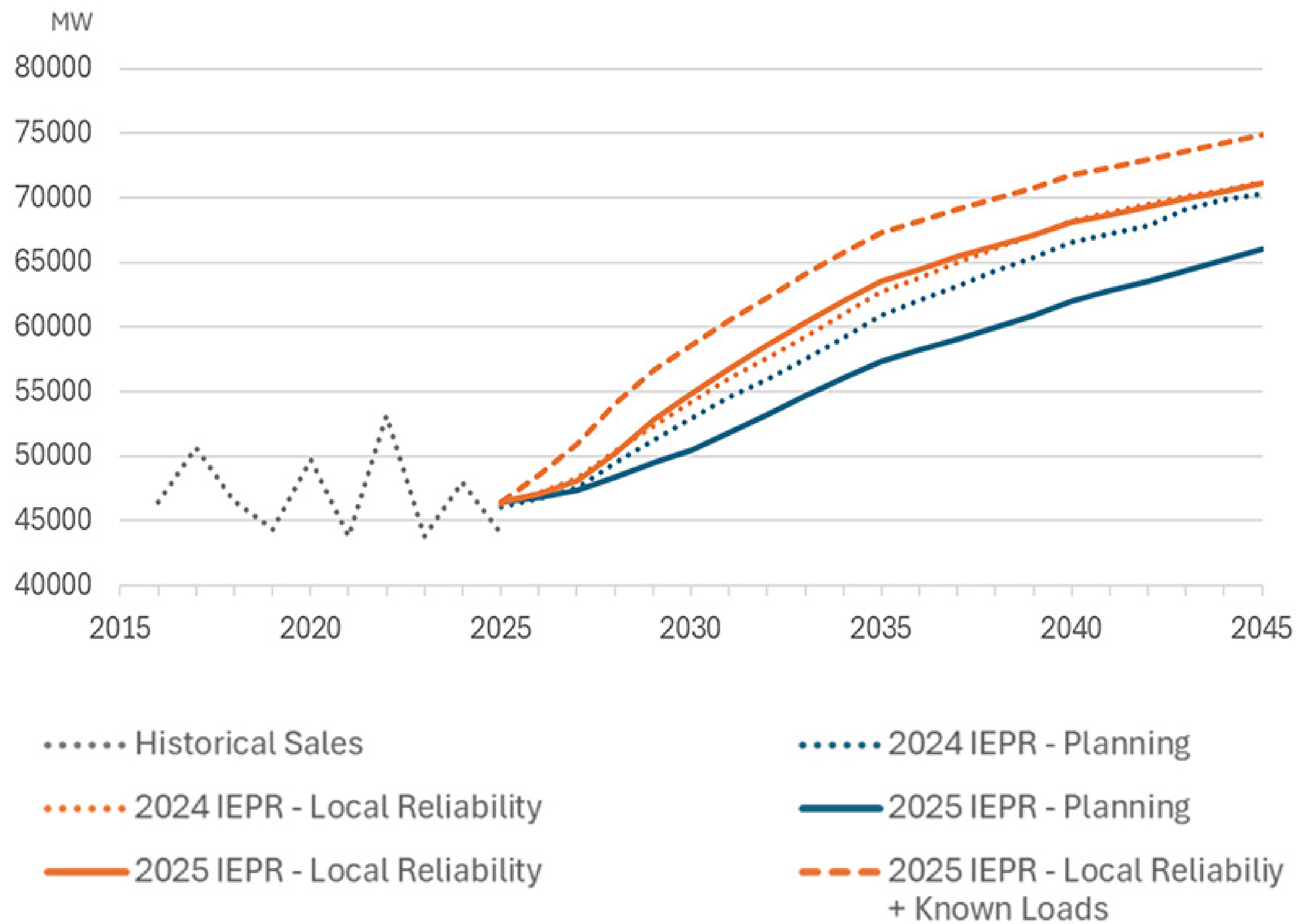
The forecast approved by the CEC will be incorporated into the agency's 2025 Integrated Energy Policy Report used to inform statewide grid planning.

CAISO's peak load is predicted to increase to about 66 GW in 2045, up from 46.5 GW in 2025. The 2024 IEPR forecast estimated 2045 peak load of about 66.8 GW. (See *Data Centers to Drive Calif. Power Demand, Sales*.)

The adoption of electric vehicles is the biggest driver of peak load growth at 8,234 MW, followed by new data centers (4,721 MW), fuel substitution from electrification (4,464 MW) and climate change impacts (1,811 MW), according to CEC lead forecaster Nick Fugate. New consumption outside those categories accounts for 6,011 MW of peak load growth.

Fugate noted that the 2025 forecast is the first for which the CEC has considered using "known load" data in its forecasts, which include "energization requests at the distribution system level" and "project-level data" from investor-owned utilities — many of which are proposed data centers.

Still, the CEC decided not to include



Increased adoption of EVs is expected to be the biggest driver of CAISO peak demand through 2045. | *California Energy Commission* known load data in this round of planning forecasts because it lacked historical records to examine "when evaluating key assumptions made in our analysis," Fugate said. The agency did provide alternative forecasts that reflect those data, and Fugate said the agency will continue to monitor known loads in 2026 and 2027 for possible inclusion in future planning forecasts.

"The approach we've taken to determine incrementality to our forecast allows for substantial room for double counting," Fugate said. "It's meant to give a bookend estimate to cover the very high-end risk, rather than to project a most likely outcome at the system level. So, while we are working with the IOUs to sort through the energization timelines to better understand this data, to validate our key assumptions and to refine our analytical approach, there is still this question of how to mitigate potential risk applied by known loads data."

The forecast's "high case" shows that California's annual electricity consumption could rise to 450 TWh in 2045, compared with about 280 TWh in 2025. By comparison, the state's consumption was 270 TWh in 2005. (See *Calif. Electricity Consumption Headed off the Charts, CEC Forecast Shows*.)

The high case shows a compound annual grow rate (CAGR) of 4.2% from 2024 to 2030 and 1.5% from 2030 to 2045, translating to 2.3% over 2024-2045.

For the "mid case," the CAGR figures are 2.3%, 1.7% and 1.9%, respectively, with 2045 consumption estimated at just above 400 TWh.

"This is one of the most important aspects of the commission's role and job, and one that I've always been very, very fascinated with and interested in," Commissioner Nancy Skinner said ahead of the vote during the CEC's monthly business meeting Jan. 21.

But speaking on behalf of the California Coalition of Large Energy Users during the meeting, Meredith Alexander said the group was troubled by the CEC's decision to exclude known loads from its planning and local forecasts.

"At this point, we're concerned that there could be real effects on reliability and costs in the next few years, if the forecast is artificially low," she said. "Load-serving entities could under-procure capacity, meaning that our load-serving entities are not sufficiently resourced to serve our new loads."

Speaking ahead of the vote, Commissioner Andrew McAllister said he was "comfortable with" adopting the forecast while acknowledging the concerns, which he said reflected the "increased uncertainty" around growing loads.

"I do want to note there are so many moving parts and so many new electric technologies being introduced to the market — really, at rates we've never seen before — that close dialogue with stakeholders and continued engagement throughout the years is more important than ever, so that we get as close to being right as we possibly can," CEC Chair David Hochschild said. ■

Oregon Gov. Appoints Group to Address Data Center Growth

Panel to Examine 'Challenges and Opportunities' Accompanying Expansion of Data Centers

By Robert Mullin

Meta data center in Prineville, Ore. | *Upsite Technologies*

Oregon Gov. Tina Kotek has appointed a new committee intended to help address the effects of the rapid growth of new data centers in the state — with a particular focus on the electricity system.

The new Data Center Advisory Committee will be "tasked with developing a set of policy recommendations and actions to address issues of statewide significance associated" with that growth, according to a Jan. 20 *press release* from the governor's office.

"Oregonians have made their concerns about rising utility bills clear. As our state faces rapid growth of data facilities, we must have frank conversations about the challenges and opportunities ahead," Kotek said in a statement. "I expect the Data Center Advisory Committee to help ensure economic growth while protecting affordable power and Oregon's critical water resources."

The committee's overarching goal: to come up with recommendations that help Oregon "take strategic advantage of the economic development opportunity" created by new data centers and other large industrial consumers of electricity "while striving to keep utility costs, infrastructure upgrades and environmental impacts sustainable for all Oregonians."

The recommendations are due to the governor by October 2026.

The release reiterates Kotek's phrasing, saying the committee will engage in a public process to understand the "challenges and opportunities" related to siting data centers and will develop recommendations that "support responsible economic development, create jobs and increase long-term revenue that will strengthen our rural communities," which are the site of many large data center operations in Oregon.

The committee is also tasked with exploring how data center development affects — and can help — Oregon's efforts to meet its climate, clean energy and natural resource management goals, including those related to water use. The press release points to a potential competition for water between agricultural users and data centers in rural areas.

The recommendations should also help the state "ensure data centers have reliable energy without burdening Oregon's ratepayers," the release said.

Kotek appointed as committee co-chairs Margaret Hoffmann, a member of the Northwest Power and Conservation Council, and Michael Jung, executive director of the ICF Climate Center.

"The challenges we currently face are complex," Hoffmann said in a statement. "I look forward to working with my fellow committee members to understand how we can co-create a vision for Oregon that supports healthy economic development, affordable energy, natural resource abundance and a future in which all Oregonians can thrive."

"To have been tapped by Oregon Gov. Tina Kotek to serve as a co-chair of the Data Center Advisory Committee is an honor that I humbly accept as a citizen volunteer," Jung said. "The governor has assembled an experienced committee to recommend priorities and actions to chart a path that balances existing priorities and new opportunities."

Other committee members include:

- Dan Dorran, Umatilla County Commission chair;
- Greg Dotson, associate professor and leader of the Energy Law and Policy Project at the University of Oregon;
- Bill Edmonds, adjunct professor at the University of Portland;
- Tim Miller, director of Oregon Business for Climate; and
- Jean Wilson, operating partner at Sandbrook Capital.

Oregon lawmakers in 2025 passed a law directing the state's Public Utility Commission to create a new retail rate class for large electricity consumers such as data centers in an attempt to shield residential ratepayers from the costs incurred to integrate those loads. (See *Oregon Governor Signs Bill to Create Data Center Rate Class*.) ■

CPUC Urges 'Stop the Brakes' Tool for EDAM Congestion Revenue Approach

CAISO also Releases Draft EDAM Benefits Calculation Methodology

By David Krause

The California Public Utilities Commission wants CAISO to come up with a way to pause settlements of certain congestion revenue allocations in the ISO's upcoming Extended Day-Ahead Market if participants begin to game the market through extensive self-scheduling.

If such "rampant pervasive behavior" appears, CAISO should consider reverting to using the ISO's prior settlement methodology, the CPUC's Energy Division said in January *comments* submitted to an ISO EDAM working group.

The congestion revenue allocation issue, specifically in situations of parallel flow on the electric system, was CAISO's top priority last year. CAISO approved a new methodology to address the concern in June 2025, and FERC approved the methodology two months later. (See *CAISO's EDAM Scores Simultaneous Wins at FERC*.)

Under the new methodology, certain congestion revenues stemming from parallel flows will be allocated to the BAA where the energy is scheduled rather than where the constraint is located — the previous methodology. Those revenues will be allocated based on a transmission customer's eligible firm Open Access Transmission Tariff transmission rights submitted and cleared as day-ahead balanced self-schedules.

However, the new methodology will maintain a "suspected underfunding problem for the immediate future if other BAAs decide to self-schedule their bids in order to receive this congestion revenue," the CPUC said.

"The expansion of the day-ahead market should not come at the expense of California ratepayers, who have invested millions, if not billions of dollars, into building a reliable grid," the CPUC said. "Therefore, rather than allocating away congestion revenue tied to parallel flows to the BAA causing the parallel flow, any long-term CRA methodology should return that congestion revenue to the BAA in which the constraint occurred."

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Although the new allocation methodology has flaws, it was necessary to implement "as a stopgap measure for EDAM go-live to occur on time," the CPUC added.

The CPUC recommended CAISO build out a "stop the brakes" mechanism, such as a pause in settlements, if the new methodology starts to show signs of gaming.

In December, CAISO published a proposed *set of design principles* that would help eliminate or reduce self-schedule incentives in the approved congestion revenue allocation design. Self-scheduling incentives could lead to significant unintended cost shifts, experts cautioned earlier in 2025. (See *CAISO Looks to Eliminate Self-schedule Incentives in EDAM Congestion Revenue Design*.)

The CPUC also asked CAISO to confirm the ISO's settlements system will be able to break out the congestion revenue tied to a parallel flow that crosses multiple BAAs. This potential issue will not be a concern when EDAM launches with PacifiCorp as its first participant in May 2026, but the ability to break apart congestion revenues will become more important when Portland General Electric and other entities join the market later in the year and in 2027, the CPUC said.

The agency also asked CAISO to clarify how it is treating congestion revenue tied to parallel flows caused by flows from another market, such as Markets+.

"Is this congestion revenue assigned to the BAA in which the constraint occurs, or is this congestion revenue returned to the market participant in the other market?" the CPUC said. "If the latter, has CAISO initiated these conversations with Markets+? Or does EDAM simply keep these congestion revenues?"

EDAM Benefits Approach Drafted

Separately, CAISO on Jan. 20 published its *draft methodology* for how the ISO and EDAM participants will estimate EDAM's gross economic benefits.

The draft proposes to calculate EDAM benefits based on production cost savings in the electric system with EDAM versus the cost of the system without EDAM.

For hydroelectric resources, the EDAM benefit methodology will use an adjusted bid value to calculate production costs of the resource. This is because hydroelectric market bids might include both the value of water and certain external limits, CAISO says. Some of these external limits include FERC minimum flow requirements, recreational reservoir levels and forecast reservoir level targets, the draft says.

Estimating EDAM benefits does not require additional market tools or external data sources, and EDAM participants are not required to submit more data than what they already submit in a market run, the report says.

CAISO plans to finalize the benefits calculation methodology in the first quarter of 2026 before EDAM opens in May. ■

FERC Approves License for Goldendale Hydro Project in Wash. State

By Elaine Goodman

FERC has approved a 40-year license for a proposed 1.2-GW pumped hydroelectric storage facility near the city of Goldendale in Klickitat County, Wash. (*P-14861-002*).

According to the commission's order, approved at its monthly opening meeting Jan. 22, Rye Development will build and operate the closed-loop, 12-hour Goldendale Energy Storage Project along the cliffs of the Columbia River Gorge and near the John Day Dam. It will include two reservoirs, one at the bottom of the cliffs and another about 2,300 feet higher.

A powerhouse built in an underground cavern will contain three, 400-MW pump-turbine units. A 500-kV transmission line will connect the project to the Bonneville Power Administration's system through the existing John Day substation. The project is expected to generate power eight hours on a typical day and up to 12 hours a day if needed.

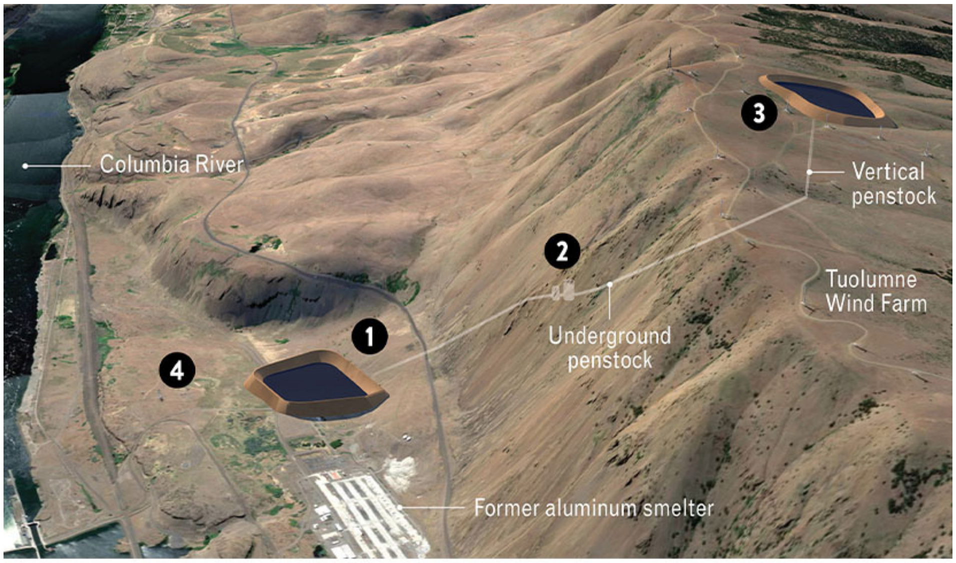
"The energy produced will be delivered to the wholesale market to be purchased by utilities in the Pacific Northwest and California to help satisfy periods of peak demand and provide grid flexibility," FERC said in its order.

According to the project's *website*, it has a price tag of more than $2 billion. The expected commercial operation date is 2032.

Erik Steimle, Rye's chief development officer, called the approval "a landmark moment for the Pacific Northwest."

"With electricity demand and energy costs on the rise, this license represents a huge step toward a more reliable grid and affordable energy prices for the region," Steimle said in a statement.

The reservoirs initially will be filled with 7,640 acre-feet of Columbia River water bought from Klickitat Public Utility District. An additional 360 acre-feet will be purchased each year to make up for water loss from evaporation and seepage. The initial fill will take place over seven months, from September through March, to avoid Columbia River flow reductions that could delay salmon smolt migration.



1. The **LOWER RESERVOIR**, located on an old industrial site, would be filled with water once and replenished annually to compensate for minimal evaporation.
2. The **UNDERGROUND POWERHOUSE** would include three pump turbines with a total capacity of 1,200 megawatts, or enough to power 500,000 homes.
3. The **UPPER RESERVOIR** would store excess power generated by local wind farms.
4. The project would deliver **ON-DEMAND** renewable energy to the grid through existing power lines.

The Goldendale Energy Storage Project is planned near the Columbia River in Washington state. | *Goldendale Energy Storage LLC*

Why This Matters

The 1.2-GW Goldendale pumped hydro storage project is touted as vital to meeting resource adequacy in the Pacific Northwest and California.

The project area is within Klickitat County's Energy Overlay Zone, which is intended to streamline energy development. The upper reservoir site is within the Tuolumne wind farm.

The lower reservoir is planned at the former site of Columbia Gorge Aluminum smelter. The landowner and the former smelter operator are working with the state on cleanup efforts, and project owner Copenhagen Infrastructure Partners has pledged $10 million to help.

The state's Department of Ecology issued a water quality certification for the Goldendale project in May 2023, which was upheld on appeal in January 2025.

The project faced opposition from members of the Yakama Nation, Umatilla Tribes, Confederated Tribes of the Warm Springs Reservation of Oregon and Nez Perce Tribe. It is on property that has historical significance and is used for sacred ceremonies. (See *Wash. Approval of Pumped Storage Project Sparks Dissent*.)

The FERC order noted that Rye proposed protecting cultural resources and mitigating unavoidable impacts to historic sites through a historic properties management plan. Other measures include consulting with tribes to provide post-construction access to the project area for cultural programs and to ensure construction doesn't block access to traditional fishing areas.

Rye is a partnership between EDF power solutions and Climate Adaptive Infrastructure. It is also developing the 393-MW, eight-hour Swan Lake pumped storage project in Klamath County, Ore., and the 266-MW Lewis Ridge pumped storage project in Bell County, Ky. ■

NWPCC Grapples with Data Centers in 9th Power Plan

Council Planning for Data Center Uncertainty

By Henrik Nilsson

Data centers bring new regional planning challenges for the Northwest Power and Conservation Council's upcoming power plan, the organization said during a recent meeting.

The council discussed data centers *during a meeting* Jan. 13.

For NWPCC, data centers will guide part of the resource recommendations in the council's upcoming Ninth Power Plan. The council is required to develop a plan for the region and the Bonneville Power Administration under the Northwest Power Act of 1980 "to ensure an adequate, efficient, economical and reliable power supply for the region."

NWPCC publishes a plan every five years, according to the organization's website. (See *NWPCC Considers Trump, Data Centers in Regional Power Plan*.)

"Data centers are part of our regional load growth," Jennifer Light, director of power planning at NWPCC, said during the meeting. "We have to grapple with it. It is part of the regional plan that we're going to need to plan for. And so we will be needing to address this large load in our plan in some way, in terms of resource recommendations, as well as other supporting recommendations."

A challenge in planning for data centers is how much projected load will materialize, Light noted.

One way in which NWPCC plans for the forecasting uncertainty in the upcoming plan is by considering three different trajectories of data center load growth: low, mid and high.

The low forecast predicts a slowing down of current trends, the mid forecast is a continuation of trends, and the high forecast reflects utilities and BPA's growth expectations, according to NWPCC's presentation slides.

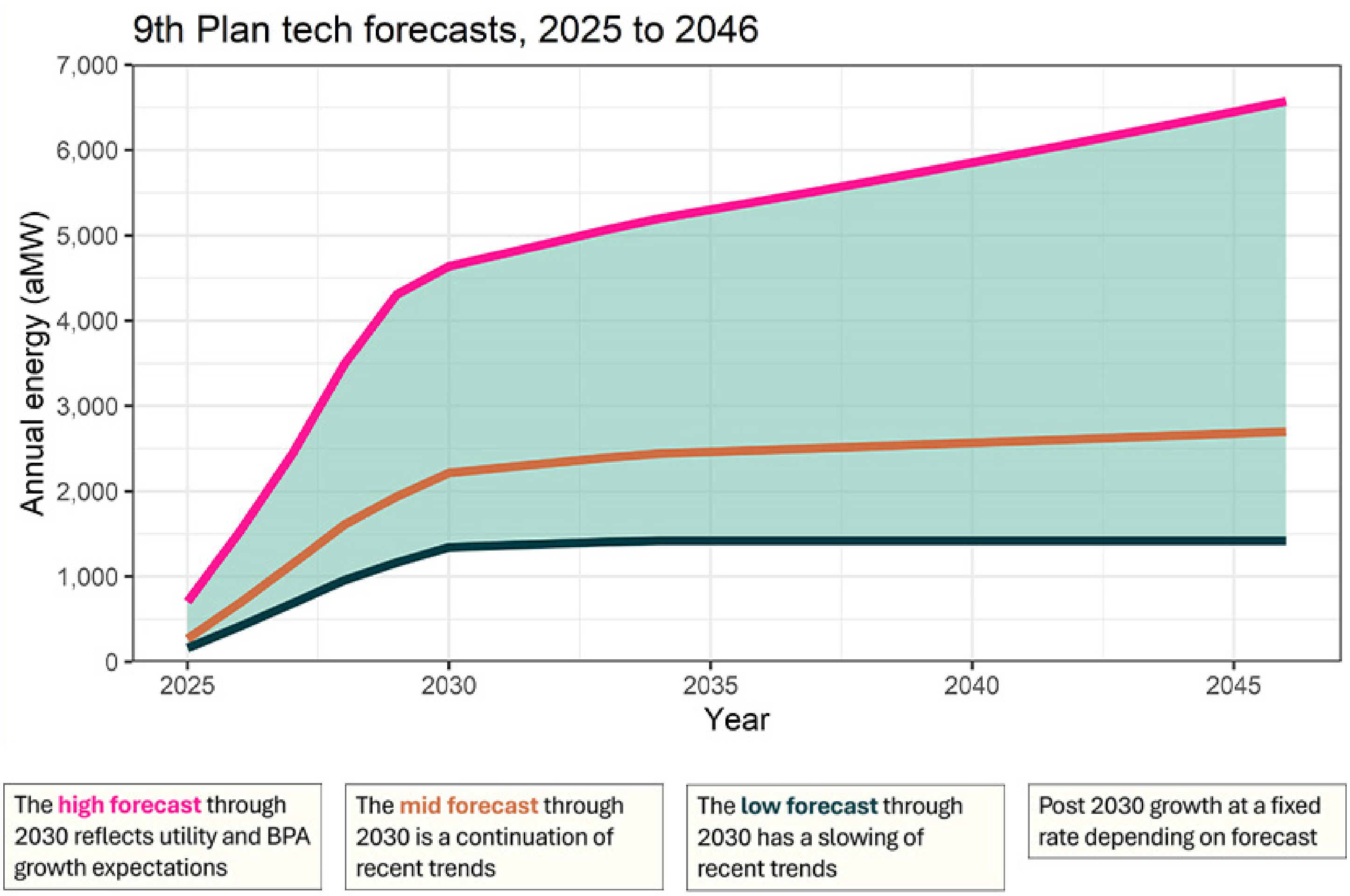
Under the high forecast, data centers' energy use is expected to reach more than 6,000 aMW by 2045, according to the slides.

"We want to make sure we have a robust strategy for the region and for Bonneville

Notable Quote

"We want to make sure we have a robust strategy for the region and for Bonneville regardless of where this data center load comes."

— Jennifer Light, NWPCC



Data centers pose planning challenges for stakeholders in the Pacific Northwest. | *Northwest Power and Conservation Council* regardless of where this data center load comes," Light said.

Under the Power Act, data centers are considered new large single loads and will receive different treatment by BPA. Data center loads are not eligible for BPA's preference rates, such as Tier 1 or Tier 2 rates, according to NWPCC's presentation slides.

Tier 1 "non-slice" contracts represent most of BPA's power sales. "Non-slice" refers to a type of contract in which the customer is guaranteed a specified volume of energy regardless of conditions on the hydro system; in contrast, total volumes delivered to "slice" customers can vary based on availability. (See *BPA Triggers $40M Surcharge Following Low Water Years*.)

If requested by BPA's utility customers, the agency can sell power to data centers under the New Resource Rate, but the timeline from request to delivery requires a study that can take multiple years to ensure BPA can find and transmit power to serve those large loads.

BPA's current utility customers have long-term contracts that guarantee their access to BPA's existing system. Any power BPA provides under the New Resource Rate would be based on the much higher cost of new acquisitions, costs that would also be available from other providers, likely with more flexible terms than BPA can provide based on the agency's statutes.

"I do not expect much, if any, of this data center load growth to go onto the Bonneville's obligation," Light said.

"This doesn't mean Bonneville might not have actions they can do in support of regional efforts," Light said. "But for the obligation piece, the data center load is probably not going to Bonneville, at least the vast majority of it."

Looming Shortfalls

However, NWPCC will need to address data centers in the broader regional strategy and focus on cost-effective resources to meet load growth and other additional recommendations, such as siting considerations, resource sharing and transmission constraints, Light noted.

The discussion follows a September 2025 study on Northwest resource adequacy by Environmental and Energy Economics that found "accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030" and that "load growth and retirements mean the region faces a power supply shortfall in 2026." (See *9-GW Power Gap Looms over Northwest, Co-op Warns*.)

In an effort to address the costs associated with data centers, Oregon lawmakers passed House Bill 3546 to create a separate customer category for large energy users, such as data centers, and require those users to pay a proportionate share of their infrastructure and energy costs. Gov. Tina Kotek signed the bill into law in June 2025. (See *Oregon House Passes Bill to Shift Energy Costs onto Data Centers*.)

The law defines a large energy use facility as one that uses more than 20 MW. It applies only to Oregon's investor-owned utilities.

On Jan. 20, Kotek launched a statewide Data Center Advisory Committee, tasked with developing policy recommendations to address challenges associated with the growth of data centers across Oregon. (See related story, *Oregon Gov. Appoints Group to Address Data Center Growth*.) ■

ERCOT Finds Stakeholder Support for Batch Process for Large Loads

By Tom Kleckner

AUSTIN, Texas — ERCOT says there is "broad agreement" from stakeholders that the grid operator's batch-based approach for interconnecting large loads is necessary.

Jeff Billo, ERCOT vice president of interconnection and grid analysis, told the Texas Public Utility Commission during its Jan. 15 open meeting that it has only begun to engage stakeholders on the batch process, but a couple of themes have already stood out (*59142*).

"Everyone that we have talked to so far has been supportive of us moving to a batch study process and moving away from the current process," Billo told commissioners. "I think one of the reasons is … that there is a lot of uncertainty in the current process. We have this issue today where loads go through the study process, and then something happens — maybe another load in their neighborhood moves forward and meets their financial commitment obligations and that load is not included in the other project study … and we're kind of caught in this restudy loop for a lot of these projects."

ERCOT's Jeff Billo updates Texas regulators on the batch study process. | *AdminMonitor*

Other themes outlined by Billo included: uncertainty in the current process creating risk for developers of existing interconnection requests; transparency and consistency in the batch process; and aligning the process with ERCOT's transmission-planning work.

ERCOT CEO Pablo Vegas unveiled the draft process in December, calling the wave of large loads looking to interconnect "fairly unprecedented." The gird operator had 63 GW of interconnection requests from large loads at the end of 2024. That number has mushroomed to 232 GW as of January, according to staff's latest data. (See *ERCOT Again Revising Large Load Interconnection Process*.)

With the batch process, ERCOT will group together large load requests to be evaluated, rather than rely on the current individual studies that transmission service providers conduct. The batch studies will determine the amount of requested load that can be reliably served each year over a six-year period and the transmission upgrades needed to accommodate the full load requested.

The grid operator says a "Batch Zero Study" will likely be needed to transition from the current process, which was just documented in December by a *rule change* to the Planning Guide. That study will set a foundation and baseline for future studies, which could happen several times a year for several years.

Billo said the first batch study will break the cycle of restudies and "get those projects out" without creating a restudy loop or uncertainty. The first batch will take projects that are already under ERCOT review, currently totaling about 7.4 GW.

"We are still really early in the process of designing how that batch study would work, but we hope to bring more details on that in the coming weeks," he said.

ERCOT staff plan to use its Large Load Working Group as an engagement forum with stakeholders, as well as updating the Technical Advisory Committee and PUC during their next regularly scheduled meetings. During a Jan. 21 discussion with TAC, Billo deferred most questions to a Feb. 3 workshop on the batch process.

"We're going to get through everything that we need to get through that day," Billo promised TAC members. "We will lay out as many details on that framework as we can … [understanding] that the framework will be in pencil. We want the stakeholder feedback."

A second batch-process workshop is tentatively scheduled for Feb. 12.

"And then our homework is due to the commission," Billo said, pointing to the PUC's Feb. 20 open meeting. ■

ERCOT Stakeholders Mark TAC's 30th Anniversary

Staff Addressing 137 GW of Large Load Interconnection Requests

By Tom Kleckner

AUSTIN, Texas — ERCOT stakeholders used their first Technical Advisory Committee meeting of 2026 to mark the committee's 30 years of existence and achievements, sharing memories of their work together and recognizing members past and present.

"It has been an honor and privilege to serve on this committee and contribute to the greatest competitive retail and wholesale power market in the world," Reliant Energy Retail Services' Bill Barnes said during TAC's Jan. 21 meeting.

The committee, composed of several subcommittees and working groups, recommends policies and procedures to ERCOT's Board of Directors and is responsible for prioritizing projects through protocol revision requests, system change requests and guide revisions.

SPP staff went through their files and found the names of 64 members who have served at least five years on the committee. Mark Dreyfus, who represents the city of Eastland and other municipalities as part of TAC's consumer segment, said he knew all the people on the list, calling some "giants of the industry." He reserved singular praise for one past member: Reliant's John Meyer.

"I hope there are statues to him in the office building," Dreyfus said. "He led the stakeholders when we developed these processes and when we developed the original protocols, and he really deserves all our honor and recognition. If you don't know him, it would be really good to talk to somebody and find out what he was about and why he took the time to create this process."

American Electric Power's Richard Ross, the only member with 25 years of service, said over the phone that TAC and ERCOT's stakeholder process "really does cast a very big shadow."

"It cast a shadow to the north and had a heavy influence on my experience with trying to get SPP's stakeholder process set up in much the same way, with the way we so transparently change rules and give everyone a free opportunity to comment and debate," Ross said. "If you ever looked at the process in SPP, you would see a great deal of similarities from things that we copied from."

Engie's Bob Helton (left) and Constellation's Bryan Sams, with a combined 26 years of TAC membership, reminisce about their experiences. | © *RTO Insider*

Barnes recalled the "completely ridiculous process" in the zonal market that predated the current nodal framework, where the zones' boundaries would be redefined every year. He said "millions and millions of dollars amongst companies" would change hands.

"It was incredibly contentious and also extremely entertaining to be a part of," he said. "One particular year … it literally moved a large coal plant from one zone to the other. I just remember Richard [Ross] playing a very critical part of the final vote, which I think it probably took three or four attempts to get through."

Ironically, Ross gave up his seat this year and has been replaced by AEP's Erin Rasmussen, one of three new *TAC members*.

"I'm watching from afar this year, but thank you for 25 years," Ross said. "Keep up the good work."

Engie's Bob Helton, another TAC veteran, saw his 18 years of service elevated to 19 in real time when ERCOT staff found a Robert T. Helton mentioned in the files.

"This has to be wrong, ok? It can't be. I'm not old enough to have done it," Helton said. "I've served with pretty much everybody that's on that list and I've served with a lot of very, very good people. We've made a lot of good decisions to make this market, as Bill said and it's been noted, as the best in the country. We've gone through a lot of adversity. We've had some fun."

Large Load Issues Pile Up

When TAC got down to the more mundane business at hand, ERCOT staff told members that the grid operator's large load interconnection queue had dropped from 237.2 GW to 232.5 GW in January after several cancellations in December.

The great majority of requests (199.3 GW, or 85.7%) are for standalone facilities.

"We do expect that there may be some additional projects that are cancellations as well," ERCOT's Agee Springer said, noting that large loads do not need to explain why they are pulling projects from the queue.

The grid operator plans to introduce a quarterly stability assessment (QSA) for large loads in February to support those preparing to energize. It would be one of the first times ERCOT has published a structured QSA framework for tracking readiness and energization of large loads, *according* to consulting firm Electric Power Engineers.

"You need to pay attention to the QSA's dates. [Large loads] are coming much faster than you think," Longhorn Power's Bob Wittmeyer, chair of the Large Load Working Group, told the committee.

ERCOT's Jeff Billo told members that staff will reveal a draft framework of the proposed batch interconnection process for large loads during a Feb. 3 workshop. These large loads are currently studied individually, but under the batch process, they would be grouped and evaluated all at once. (See *ERCOT Finds Stakeholder Support for Batch Process for Large Loads*.)

Billo said ERCOT will likely request a good-cause exception from the Public Utility Commission after a recent *rule change* that requires large loads go through a full interconnection study similar to those generators undergo. Assuming the board approves the process, staff will have to file protocol changes to codify the batch studies.

"This is necessarily moving quickly because there are a lot of projects, a lot of these large load projects that are being developed," he said. "The customers who are developing those want certainty as to how this is going to work, how this is going to impact their project, so we want to try to provide that."

Richard Ross, AEP | © *RTO Insider*

Jeff Billo, ERCOT | © *RTO Insider*

Smith, Henson to Lead TAC

Members re-elected Jupiter Power's Caitlin Smith and Oncor's Martha Henson as TAC's chair and vice chair, respectively, for 2026. It will be Smith's third year leading the committee.

"I'm planning on this being my last term," she said.

Smith noted TAC's accomplishments during the year, topped by getting the Real-time Co-optimization Battery (RTC+B) project's last items "across the finish line" before it went live. She pointed also to stakeholders' endorsement of ERCOT's first 765-kV projects and growing TAC's relationship with the board.

"We have done a lot … but we're looking at a lot of work, namely [dispatchable reliability reserve service (DRRS)] and the load ride-through requirements we need to get done by the first half of the year. So, it's not all fun and games, but [I'm] excited."

Tier 1 Project on Combo Ballot

TAC's unanimously approved combination ballot, or its consent agenda, included a $117.4 million transmission build that was reclassified as a Tier 1 project and needing board approval.

South Texas Electric Cooperative submitted the project, which will accommodate a 300-MW ammonia plant near Victoria on the Gulf Coast, costing an estimated $65.5 million. ERCOT's Regional Planning Group analyzed eight options and chose one of four short-listed alternatives, all with higher price tags.

Staff attributed the cost increase and reclassification to the higher 138-kV rebuild capability standard on AEP's portion of the project. AEP's Doug Evans said tariff rates on some steel and aluminum items increased between 15 and 50%, also increasing cost estimates.

The project is expected to be in service in June 2028.

The combo ballot also included the withdrawal of a change to the Nodal Operating Guide (*NOGRR264*) for an earlier iteration of the DRRS product (See *RTC Deployed, ERCOT Takes on New Challenges in 2026*); TAC's *subcommittee and subgroup leadership* for 2026; and three protocol changes (NPRRs) and two revisions to the Planning Guide that, if approved by the board, will:

- *NPRR1304*: Incorporate the Other Binding Document "Procedure for Identifying Resource Nodes" into the protocols to standardize the approval process.
- *NPRR1305*: Add the Other Binding Document "Counter-Party Credit Application Form" into the protocols to standardize the approval process.
- *NPRR1311*: Correct an error in the real-time reliability deployment price adders' calculation for ancillary services when ERCOT is directing firm load shed during a Level 3 energy emergency alert in the RTC+B's protocols, ensuring final ancillary services prices cannot exceed $5,000/MWh.
- *PGRR127*: Outline the additional generators that may be added to the planning models to address the generation shortfall introduced by the implementation of *House Bill 5066*'s requirements and increased load growth. The PGRR would also add a supplemental generation sensitivity analysis for Tier 1 Regional Planning Group project evaluations to minimize the effects of the additional generation on transmission project evaluations.
- *PGRR132*: Clarify that new resources must interconnect to ERCOT through a new standard generation interconnection agreement. ■

Hydro-Québec Halted NECEC Deliveries amid Reliability Concerns

By Jon Lamson

As extreme winter weather descended on the Eastern U.S. and Canada, Hydro-Québec suspended power exports to ISO-NE on the New England Clean Energy Connect (NECEC) transmission line because of reliability concerns in Québec starting on the afternoon of Jan. 24.

The suspension continued throughout tight system conditions across the Northeast on Jan. 25 and 26.

"The polar vortex has brought extreme and sustained cold air across Québec," Serge Abergel, chief operating officer for Hydro-Québec Energy Services, said in a statement. "The demand for power in Québec caused us to suspend deliveries over the New England Clean Energy Connect from Saturday afternoon until the present (with partial deliveries occurring between 1 p.m. and 3 p.m. on Sunday)."

He said Hydro-Québec expects deliveries to resume early Jan. 27, but he noted that "there could be yet further interruptions at peak hours over the next several days."

According to ISO-NE data, NECEC deliveries dropped from about 1,100 MW to zero over a half-hour period midafternoon Jan. 24. Hydro-Québec sent power over the line for about two hours on the following day, sending up to about 600 MW before again cutting deliveries.

The loss of supply from the NECEC line appears to have significantly affected real-time energy prices: The ISO-NE real-time Hub LMP more than doubled during the 40-minute period NECEC cut supply Jan. 24, while the brief burst of supply Jan. 25 coincided with about a 33% decline in the hourly real-time LMP despite relatively steady demand.

Amid high prices in New England, ISO-NE has consistently been exporting power to Québec over the Phase 2 transmission line since the afternoon of Jan. 24, including about 830 MW during that day's evening peak.

The NECEC line began commercial operations Jan. 16. (See *NECEC Transmission Line Ready to Begin Commercial Operations*.)

Why This Matters

The suspension of supply on the new transmission line amid tight system conditions in New England likely led to significantly higher energy prices and is a potentially concerning sign for the project's near-term reliability benefits.

The project includes supply contracts between Hydro-Québec and Massachusetts electric utilities requiring the company to send firm power to ISO-NE. The company does not have new capacity supply obligations associated with the line.

Hydro-Québec could face significant penalties for falling to meet the delivery requirements of the contracts. According

Beaumont Generating Station on the Saint-Maurice River in Québec | *Hydro-Québec* to the power purchase agreement, supply interruptions that are not the result of a *force majeure* or a physical outage on the line can be cured by the additional deliveries within the same year or following year. Delivery shortfall during peak hours can only be cured during peak hours, and delivery shortfall in the winter can only be cured in the winter (D.P.U. 18-64, *et al.*).

"We are aware of the historic constraints on the Canadian grid due to the extreme cold," said Maria Hardiman, a spokesperson from the Massachusetts Executive Office of Energy and Environmental Affairs.

"Hydro-Quebec is facing steep penalties for each day they are not providing power to Massachusetts, and we know they are working to resume power as quickly as possible," Hardiman said. "Our contract ensures that ratepayers will still see lower-priced electricity, regardless of the power flowing over the line."

Robert McCullough, principal of McCullough Research, said the suspension on the NECEC line appears to be a product of Hydro-Québec's slim reserve margin for the current winter. According to the Northeast Power Coordinating Council's 2025/26 winter reliability *assessment*, Québec had about a 1% reserve margin. Hydro-Québec's peak load exceeded its 50/50 winter forecast by over 200 MW on Jan. 25.

McCullough attributed the slim reserve margin to "combination of bad weather, neighbors not able to help and insufficient maintenance on some of the dams." NPCC's report notes that Hydro-Québec's available winter capacity was reduced by 5,594 MW because of maintenance and derates.

Abergel called the contention of insufficient maintenance "simply not accurate."

In New England, ISO-NE peak load reached 20,182 MW on the evening of Jan. 25, slightly exceeding the region's 90/10 winter forecast. Hourly Hub LMPs have reached as high as $777 $/MWh.

The RTO has avoided the need to take emergency actions throughout the weather event. It issued a precautionary alert on the morning of Jan. 25 and obtained a waiver from the U.S. Department of Energy allowing generators to override air permit limits to provide extra power.

Dan Dolan, president of the New England Power Generators Association, said the ISO-NE fleet "has performed exceptionally well this weekend using every different fuel and technology to maintain reliable, stable operations through arctic temperatures, heavy snowfall and even needing to send power to support our neighbors in Quebec."

He highlighted the significant role oil generation has played in maintaining grid reliability. With gas generation limited because of high demand for heating, oil generation has consistently accounted for roughly a third of generation in the region since the suspension of deliveries on the NECEC line.

"Part of the diverse generation mix in New England is a large capability to use oil in periods of stress," he said. "That has happened at a tremendous scale, which creates strain on fuel infrastructure. But the system is holding up through this first stretch."

With more cold weather in the forecast over the next few days, "it is all hands on deck," Dolan said. ■

Energy Affordability Dominating State Politics Across New England

By Jon Lamson

Debates about affordability continue to dominate state-level energy policy debates throughout New England, shifting the focus away from decarbonization, a panel of experienced lobbyists said at a webinar held by the Northeast Energy and Commerce Association on Jan. 16.

All six New England states face gubernatorial elections in 2026, while U.S. Senate races in Maine, Massachusetts and New Hampshire are drawing significant attention. As federal and local political races heat up, energy affordability is poised to be a key issue, several speakers said.

Christopher Boyle, a lobbyist and former Rhode Island House majority whip, said he has seen "a sea change in how we're looking at energy in the General Assembly and the governor's office."

He noted that Rhode Island Gov. Dan McKee (D) did not mention climate change during his Jan. 13 State of the State *address*, and *has proposed* pushing the state's target for achieving 100% clean energy from 2033 to 2050. McKee also has proposed a cap on energy efficiency spending.

Shutterstock

In Massachusetts, Republican challengers have frequently criticized Gov. Maura Healey on the topic of energy affordability, said Jen Gorke of TSK Associates. She noted that the spike in energy prices in the past winter "led to affordability being on the agenda in a way that I have never seen it in Massachusetts."

But while there is broad agreement that energy affordability is a problem that must be addressed, there is significant disagreement about its root cause, Gorke said, noting that "if you don't agree on the cause, you can't agree on the solution."

"There's kind of two camps, and a lot of people in the middle," she added. "Some see our leadership on clean energy and climate as the driver of high cost, while others see those exact same things as the path to lower cost and greater stability and reliability in the future."

A pair of energy bills introduced in Massachusetts in 2025 exemplified some of the divergence in approaches to addressing energy affordability.

In May, the Healey administration proposed a wide-ranging bill that would tighten regulations around residential competitive electricity supply; allow utilities to issue bonds to help cover costs of the clean energy transition; expand the state Department of Energy Resources' (DOER's) procurement authority; and reduce net metering rates for new large solar resources. (See *Mass. Gov. Healey Introduces Energy Affordability Bill*.)

In contrast, the House members of the legislature's Joint Committee on Telecommunications, Utilities and Energy (TUE) advanced a bill in November that drew significant public pushback from environmental advocates. While the bill included similar competitive supply regulations and expanded procurement authority for the DOER, it also would cut energy efficiency spending, reduce the annual requirements of the state's Renewable Portfolio Standard and undermine several key components of the state's heating electrification strategy. (See *Top Mass. House Members Seeking Major Rollback of Climate Laws.*)

Why This Matters

Increased emphasis on affordability has put increased scrutiny on state-level renewable programs and goals, with potential effects on clean energy development, energy efficiency investments and electrification initiatives.

These debates may heat up in 2026; House lawmakers seek to advance a version of the TUE bill out of the House Ways and Means Committee, while the Senate likely will produce its own version of an energy bill. Historically, the Senate has tended to side with climate advocates on energy policy debates and recently has looked to cut energy costs by reining in spending on the gas system.

Gorke added the Trump administration continues to have a major effect on all aspects of state government, including energy policy, with particularly large impacts on the state's offshore wind industry.

"Offshore wind was the key tool for Massachusetts and was really expected to carry a big share of the clean energy transition," she said. "People are trying to be very creative about how we can plug these holes and keep the momentum, but it has a big impact."

She added there's significant concern the Trump administration's antagonism toward offshore wind will have a long-term chilling effect on investment in future projects even if the current crop of under-construction projects overcomes the administration's obstacles.

"For Rhode Island, offshore wind is the holy grail of our policy," Boyle said. He added that, while Revolution Wind may be able to finish construction, the future of SouthCoast Wind is far murkier. "I think the SouthCoast project is the one that is

Continued on page 32

FERC Directs ISO-NE to Cap Pay-for-Performance Balancing Ratio at 1.0

By Jon Lamson

FERC on Jan. 22 partially granted a complaint by the New England Power Generators Association (NEPGA) about the design of ISO-NE's Pay-for-Performance mechanism (*EL25-106*).

The commission directed ISO-NE to cap the PFP balancing ratio at 1.0 but rejected NEGPA's complaint about the RTO's method of allocating stopped losses.

ISO-NE's PFP rules incentivize performance during capacity scarcity events. While all resources are eligible to earn credits, only resources with capacity supply obligations (CSOs) are subject to penalties for underperformance.

The complaint stems from a scarcity event on June 24, 2025, that coincided with ISO-NE's highest peak load in more than a decade. PFP credits totaled about $114 million during the event.

In a complaint filed in late July, NEPGA contended that a pair of "flawed rules" caused capacity resources to accrue $51 million in "improper charges" during the three-hour scarcity event.

The balancing ratio, which is used to calculate resources' performance responsibilities during scarcity events, averaged about 1.031 during the June 24 event, causing "$25 million in improper charges to capacity resources," NEPGA wrote in its complaint. It argued for a cap on the balancing ratio, writing that capping the ratio at 1.0 would prevent resources from being required to supply more than their CSOs. (See *NEPGA Seeks Relief for 'Improper' Pay-for-Performance Costs in ISO-NE*.)

The association also called for changes to ISO-NE's rules spreading the costs of under-collected PFP penalties across all capacity resources. Monthly stop-loss limits on the total penalties each resource can incur can cause under-collection of credits. Instead of charging these losses to all resources with CSOs, NEPGA proposed to deduct under-collected credits from the payment pool for overperforming resources.

Why This Matters

FERC's order comes at a time when some participants are concerned about increasing risks of scarcity events in New England.

Bellingham Energy Center in Bellingham, Mass. | *NextEra Energy*

The association noted that there was a $26 million under-collection of credits during the June 24 event. This deficit was charged to all capacity resources that did not hit their stop-loss limit during the event.

In response to NEPGA's complaint, ISO-NE did not oppose capping the balancing ratio but opposed the proposed changes to the allocation of under-collected credits. The RTO argued it is fair to allocate stopped losses to capacity resources because the stop-loss rules benefit these resources by limiting their financial risks. (See *ISO-NE Open to PFP Changes Following NEPGA Complaint*.)

In its ruling, FERC agreed with NEPGA's contention that the lack of a balancing ratio cap is not just and reasonable, noting that "in the absence of such a cap, resources with capacity supply obligations in ISO-NE may be subject to financial charges even when they are providing their maximum possible physical output during capacity scarcity conditions."

The commission wrote that, under the current design of ISO-NE's Forward Capacity Market, resources are frequently accredited near their maximum capability. Notably, this could change under the new rules proposed by the RTO in its Capacity Auction Reform project, which would accredit resources based on their expected reliability contributions during periods of shortfall and likely would reduce the overall accreditation value for many resources.

Capping the balancing ratio appears unlikely to hurt reliability, FERC wrote, reasoning that resources still would have received a significant performance incentive if the ratio had been capped on June 24. Capping the ratio at 1.0 would have lowered the effective performance rate from $9,337/MWh to $7,243/MWh during the event.

Regarding NEPGA's complaint about the allocation of stopped losses, FERC agreed with ISO-NE's argument that all capacity resources benefit from the stop-loss rules. It found the existing methodology to be "consistent with the beneficiary-pays principle."

"The stop-loss mechanism provides each capacity resource with insurance against the possibility of suffering net financial losses in excess of the stop-loss limit," FERC wrote. "Even a capacity resource that performs at its capacity supply obligation benefits from the stop-loss mechanism and should pay its share of the mechanism's costs."

FERC gave ISO-NE 180 days to file tariff changes capping the balancing ratio at 1.0. ■

ISO-NE Responds to Feedback on Asset Condition Reviewer Role

By Jon Lamson

ISO-NE responded to stakeholder feedback and provided more detail on its proposed asset condition reviewer role at the NEPOOL Transmission Committee meeting Jan. 21.

The reviewer role is intended to increase transparency and scrutiny into local transmission upgrades of existing assets. Asset condition costs have risen in recent years. According to the October *update* to the transmission owners' asset condition database, the cost of asset condition projects placed in service since the start of 2020 totals about $4.67 billion. The transmission owners forecast an additional $1.97 billion to be added to this total by the end of 2026.

The growth in costs, coupled with concerns about a lack of regulatory oversight into the spending, has driven efforts to standardize asset condition procedures and increase public information and engagement.

As proposed, the ISO-NE asset condition reviewer would have limited authority — its findings would be advisory; it would not take over management or planning responsibilities from the transmission owners; and it would not make legal determinations on the prudency of investments. However, the reviewer would provide information on asset condition projects and practices that third parties could use to challenge the prudency of projects.

"The new function is envisioned to provide an independent review and opinion of ACPs" and help the states and the public better understand "the technical merits of proposed projects," said Al McBride, vice president of system planning at ISO-NE.

The RTO aims to establish the role by January 2027, subject to FERC approval of the budget and governing documents. It plans to hire dedicated staff with technical expertise to review projects, McBride said.

In October, ISO-NE asked for feedback on the role's objectives, governance structure, criteria for project review, stakeholder engagement, ties to holistic system planning and outputs.

McBride said the feedback ISO-NE received emphasized the need for technical expertise, credibility and strong scrutiny of proposed projects.

"Respondents generally agree that the [asset condition] reviewer should produce clear, detailed reports that evaluate alternatives, technical needs and cost-effectiveness, and that these reports must be transparent, well-documented and completed before construction begins," he said.

In comments submitted in December, the New England States Committee on Electricity (NESCOE) wrote, "It is imperative that the review ultimately provide information of sufficient detail to enable states, consumer advocates and others to rely upon it to challenge or support the asserted need, the project option selected and/or costs, as needed."


A cracked wooden pole on an Eversource transmission line in New Hampshire | *Eversource Energy*

Why This Matters

The ISO-NE asset condition reviewer role would be a first-of-its-kind position in the country. Consumer advocates hope the position will help safeguard against wasteful spending.

McBride noted that the RTO received a range of feedback on the governance structure, with some stakeholders advocating for the creation of a new department within in ISO-NE System Planning "to better achieve efficiency and build towards the objectives of more holistic outcomes, such as right-sizing," while other commenters pushed for a standalone department "to better ensure impartial oversight."

After accounting for the feedback, ISO-NE proposes to create a new department in system planning. McBride said this would help avoid "duplication of expertise" and would enable "future coordination with other planning activities, such as right-sizing."

As proposed, the role would regularly report to the ISO-NE Planning Advisory Committee on transmission owner asset management practices and would review individual projects with an estimated cost of "greater than or equal to $30 million to $50 million on an individual line or at a single station/substation over a period of five years or less."

The reviewer would look to identify inconsistencies between the asset management practices of transmission owners and look for opportunities for standardization.

For individual project reviews, ISO-NE

would evaluate whether the transmission owner justified the project need and adequately evaluated project alternatives. The RTO would also give an opinion on the transmission owner's preferred solution.

Projects would not be allowed to begin construction until the review is complete. Material modifications to a project or a change in the preferred solution would trigger reevaluation by the reviewer.

To establish the role, ISO-NE plans to add a new attachment to the Transmission Operating Agreement to "establish requirements for information provision, standardization and reporting." It is targeting a technical committee vote in June on its proposal.

McBride said ISO-NE plans to discuss the "development of a right-sizing capability" after the asset condition reviewer design is largely complete, likely in the third quarter of 2026. Consumer advocates in the region have expressed a strong interest in developing a right-sizing process to prevent duplicative transmission projects and identify the potential for long-term cost savings. NESCOE wrote in its comments that establishing an asset condition reviewer should add confidence to future right-sizing discussions.

Surplus Interconnection Service

Also at the Transmission Committee meeting, ISO-NE kicked off discussions on surplus interconnection service. The RTO included the topic in its 2026 work plan at the urging of several stakeholders. It plans to analyze the current rules to evaluate stakeholder concerns and "the need for and scope of potential solutions." (See *ISO-NE Publishes Draft 2026 Work Plan* and *Stakeholder Forum: Surplus Interconnection Can Maximize Capacity in ISO-NE*.)

Alex Rost, director of transmission services at ISO-NE, noted that the RTO implemented its existing surplus interconnection service (SIS) rules in 2019 in response to FERC Order 845. He said the SIS process is intended to allow interconnection customers "to take advantage of unused capability through the use of surplus interconnection service at existing points of interconnection."

Surplus customers are not required to go through the ISO-NE interconnection process, which is part of the reason the topic has drawn interest from stakeholders. However, surplus customers still may need to undergo studies "if the performance characteristics of the new generating facilities are materially different from the existing generating facilities," Rost said.

He emphasized that surplus customers are subordinate to the original interconnection customer. If the original customer retires, the surplus customer would lose access to the surplus service. This constraint is part of the reason there is only one instance of a surplus interconnection agreement in the region, he said.

He asked for written feedback by Feb. 6 on any "outcomes stakeholders are ultimately looking for related to this review … and any use cases they can provide." ■

Energy Affordability Dominating State Politics Across New England

Continued from page 29

going to really have a material, substantial effect … it's obviously both an energy issue and a jobs issue having an impact from Washington."

As offshore wind struggles, Maine's ongoing solicitation of 1,200 MW of onshore wind in the northern part of the state appears to be increasingly important for the clean energy goals of the southern New England states, said Jeremy Payne, a Maine-based lobbyist for Cornerstone Government Affairs. (See *Maine PUC Issues Multistate Transmission, Generation Procurement*.)

Four other New England states are collaborating with Maine on the procurement, while ISO-NE's complementary Longer-term Transmission Planning procurement has the backing of all six New England states. Payne speculated Maine may look to procure some of the energy from the Millstone Nuclear Power Plant in Connecticut in exchange for Connecticut's procurement of onshore wind in the Northern Maine RFP.

Millstone is under contract with Connecticut electric utilities through 2029, with the utilities required to purchase about half of the plant's power and all its environmental attributes over the period. The state repeatedly has expressed interest in including other states in subsequent contracts.

"Connecticut has long been interested in nuclear — has long seen its value — but does believe that it has to be a regional resource, because currently the burden is on Connecticut electricity ratepayers," said Nicole Tomassetti, partner at Capitol Strategies Group.

There's broad interest across states in exploring the potential of small modular nuclear reactors (SMRs). While it's difficult to forecast future costs for the early-stage technology, a 2024 *study* by ISO-NE estimated that adding about 15 GW of SMRs by 2050 could enable the region to meet state decarbonization goals at 33% less capital cost than the renewable-dominated base scenario.

"We have a pretty big political divide here, and obviously we're in a campaign year, so that makes it even more pronounced, but I think nuclear is one of the few topics where the Democrats and the Republicans can agree that there's some potential," said Heidi Kroll, a New Hampshire-based lobbyist for J. Grimbilas Strategic Solutions.

New England has a long history with nuclear power; it was home to a boom in both nuclear development and anti-nuclear activism in the latter half of the 20th century. After a series of major plant retirements over a period of about 25 years starting in the mid-1990s, only Millstone in Connecticut and Seabrook Station in New Hampshire remain.

In Rhode Island, the mere mention of nuclear power in legislative hearings used to elicit "groans and moans and screams and eye rolling," Boyle said. "The fact that it has become part of an accepted methodology to solve this problem, I find historically very interesting." ■

FERC Rebuffs Clean Energy Orgs' Arguments Against MISO Fast Lane

Commission Finds RTO's Fast-track Process Necessary to Meet RA Challenges

By Amanda Durish Cook

FERC ruled that MISO is free to continue using its interconnection queue "fast lane," shutting down rehearing requests from several clean energy organizations.

The commission on Jan. 22 concluded again that MISO's temporary expedited queue process for generation projects deemed necessary by states is "appropriately tailored to address" near-term resource adequacy needs (*ER25-2454*).

The clean energy groups that requested rehearing included the Clean Grid Alliance, Sierra Club, Sustainable FERC Project, Natural Resources Defense Council, Southern Renewable Energy Association, Clean Wisconsin, Advanced Energy United, American Clean Power Association and Solar Energy Industries Association.

They argued MISO doesn't confront the dire resource adequacy crisis it purports to be facing, saying the RTO and the Organization of MISO States' 2025 Resource Adequacy Survey showed that by 2031,

The Takeaways

FERC ruled that states don't have to turn to the regular queue first to hunt for beneficial proposed generation, and that projects in the regular and expedited queues can be treated differently.

NextEra Energy's plans to restart the Duane Arnold nuclear plant in Iowa are included in MISO's expedited queue process. | *NextEra Energy* the footprint could have a surplus ranging from 1.4 to 6.1 GW.

The groups also said that MISO could have looked to its regular interconnection queue to find helpful generation and argued the fast lane would drain the RTO's manpower at the expense of the regular process.

FERC said that contrary to the organizations' claims, MISO has "sufficiently documented that its region is likely to face near-term resource adequacy needs" that will not be satisfied by existing projects in the regular interconnection queue.

The commission also said that regulators are under no obligation to comb through the existing queue to find a project to meet a resource adequacy need, adding that MISO's queue process falls outside of state regulators' jurisdiction.

Furthermore, FERC said once it found the fast track was a reasonable means of addressing resource adequacy risks, "we need not — and cannot under the standard applicable here — consider whether an alternative proposal that imposed this 'search for a better project' requirement might be preferable."

'Permissible Departure'

MISO created the temporary queue express lane to more quicky get necessary generation online. Throughout 2026, the grid operator will accept four 15-project cycles into the fast track.

The first two cycles, accepted in 2025, overwhelmingly comprise gas generation. MISO expects the 11 GW of new natural gas generation from this phase to begin coming online in 2028. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

FERC disagreed that it stepped outside of its precedent prohibiting discrimination in generator interconnection to approve the express lane and said its decision "arises in the particular context of a potential resource adequacy shortfall in MISO and, therefore, reflects a permissible departure from the standardized generator interconnection procedure." It found the RTO's design "contains sufficient guardrails to address the concerns relating to undue discrimination."

The commission determined that interconnection customers in the fast lane are "differently situated" than MISO's other interconnection customers and can be allowed shorter wait times, slightly different studies and ultimately pay less for interconnection service.

"To the extent [expedited] interconnection customers receive favorable terms of interconnection as part of this one-time process, we find that this treatment flows from reasonable choices in the design" of the expedited queue, FERC said in its order.

FERC added that regular interconnection customers could benefit from the network upgrades built by expedited interconnection customers.

The commission decided once more that the expedited queue can help sustain resource adequacy and said that even with the three-year grace period for expedited projects to come online, the last cycle of studied projects would be operational in August 2033 at the latest, within the timeline to address MISO's pressing resource adequacy problems.

FERC pointed out that objective regulatory agencies must verify the project need and said regulators are "uniquely positioned to see the need and review the project that is being proposed."

It also noted that expedited interconnection requests are subject to stricter requirements than those in the standard interconnection queue, including higher fees per megawatt, a $100,000 nonrefundable deposit, definitive proof of land use and a requirement to pay for all network upgrades. It said those requirements encourage only shovel-ready projects to apply.

The commission reiterated that MISO's creation of a limited, temporary process strikes a balance between ensuring resource adequacy while limiting the fast track to a manageable number of interconnection requests that can be studied quickly. The commission said despite the clean energy organizations' arguments, the process is a one-time exercise conducted over a specific time frame. It said the quarterly nature of the studies doesn't suggest that MISO plans to exceed the 68-project cap or repeat the process.

"This approach falls well within the flexibility we afford to RTOs/ISOs to design appropriate solutions to their interconnection challenges and well within a reasonable view of what constitutes a 'one-time' process," FERC wrote.

Altogether, MISO's temporary process would accommodate 68 projects, with 10 set aside for independent power producers and eight reserved for entities serving retail choice load in downstate Illinois and part of Michigan. ■

Stakeholders Suggest Cost Overruns Ubiquitous as MISO Reviews Long-range Tx Project

By Amanda Durish Cook

Stakeholders told MISO that it might have anticipated an impending cost increase for a long-range transmission project under development in Minnesota that jumped about 43% in price to nearly $1.4 billion.

The 345-kV Iron Range-Benton County-Big Oaks project in Minnesota, from MISO's 2022 collection of long-range transmission projects, is undergoing a *variance analysis* by the RTO for the cost increase. (See *MISO Launches 2nd Review of Long-range Tx Project for Cost Overruns*.)

Joint developers Minnesota Power and Great River Energy have upped costs to build the line from an originally estimated $970 million to $1.39 billion, citing an increase in labor and materials costs, an engineering refinement to substation work and routing redesigns. The project is set to connect Minnesota Power's Iron Range substation in Itasca County to Great River Energy's Benton County substation.

WPPI Energy's Steve Leovy said MISO and stakeholders could have predicted cost overruns much earlier. He noted that the developers told the Minnesota Public Utilities Commission in August 2023 that costs could range from MISO's $970 million estimate to $1.35 billion.

"It occurs to me that some of these things were known and should have been known some time ago," Leovy said of the increases during a Planning Advisory Committee meeting Jan. 21.

"I just want all of us to get a better handle on cost estimates," Leovy said. "We should have been on notice in August of 2023 that the costs would go higher. … I don't think anyone should be surprised that it ended up in that neighborhood."

Leovy said he didn't want to suggest negligence or malfeasance on the part of the developers.

Jeremiah Doner, MISO's director of cost allocation and competitive transmission, said the range Minnesota Power and Great River Energy submitted to the Minnesota PUC was not a final number, and the high end at the time represented a worst-case scenario.

Doner said the increase is a confluence of escalating materials costs and routing changes. He said the project first encountered routing cost changes because of permitting changes in Minnesota.

Great River Energy

Why This Matters

As MISO conducts reviews on two transmission projects that have exceeded cost estimates, stakeholders suggest that the RTO should expect more expensive construction processes.

"Ultimately, Minnesota decided that there were additional co-location opportunities … to minimize impacts," he said.

Some stakeholders said it shouldn't be a surprise that state commissions would want routes to use existing rights of way as much as possible.

Doner said it wasn't until the second half of 2025 that the transmission owners notified MISO of material and construction cost escalations.

"Collectively, that information drove the variance analysis trigger," Doner said. "I note that everyone wants us to move as quickly as possible through this process."

The Minnesota developers said the rise in costs for substation equipment, steel and labor accounts for 25% of the increase, while routing changes and the more fleshed-out work plan for the substation facilities account for the remaining 18%.

Doner said the developers are still trying to meet the project's original 2030 in-service date.

Ørsted's Eva Kaso-Collette asked if the timeline "slippage" brought on by the changes and review would last months or years. Doner said he could not speculate on the developers' timeline.

Doner said he similarly could not put an estimate on how long MISO's review would take.

"These truly are very case by case," Doner said of the variance analysis process. "We are going to strive to work through these as quickly as possible."

The first, $10.4 billion long-range transmission plan has grown to $10.7 billion, according to MISO's latest quarterly reporting released in September 2025.

The Sustainable FERC Project's Natalie McIntire asked if MISO transmission developers are encountering across-the-board cost increases for construction materials and whether the RTO should expect more overruns.

Doner said that while transmission owners are receiving larger-than-anticipated bids on materials, equipment and labor, it's not a universal occurrence. He also said that in some cases, transmission developers are saving money by adjusting routes.

"We are not seeing a blanket, 30 to 40% cost increase," Doner told stakeholders, though he acknowledged "upward pressure on prices and costs."

Customers Call for Tighter Variance Analysis Rules, Oversight

Meanwhile, MISO's transmission customers continue to advocate for narrower triggers to set variance analyses in motion, citing escalating costs.

They have asked MISO to equip the variance analysis with a 20% overbudget threshold to trigger the study (instead of 25%) and to consult with third-party experts and its Board of Directors on projects' fates. (See *MISO TOs Oppose Tx Cost Containment Suggestions*.)

At a Dec. 16 stakeholder meeting on cost allocation, Ken Stark, with the Coalition of MISO Transmission Customers, said the "Damocles sword of high energy costs does hang over consumers' heads in the years to come."

Stark said the MISO industrial customers' viewpoint remains unchanged, especially given booming transmission planning and ratepayers' rising bills for electricity service. He said MISO's second variance analysis is further proof of the need.

After it wraps up a variance analysis, MISO can decide either to let projects stand as they are, develop a mitigation plan for them, cancel them or assign them to different developers if possible.

Stark argued that the board should approve the outcomes of variance analyses. "The MISO board approves the MTEP [MISO Transmission Expansion Plan]. It only makes sense they should approve material changes to the MTEP," he said.

At the time, Leovy said it might be time for MISO to sharpen its cost estimation so that it better anticipates financial impacts to transmission projects.

Relatedly, the Organization of MISO States has engaged with nonprofit Regulatory Assistance Project for "technical assistance" on transmission cost oversight over the first quarter of 2026.

MISO has two active *requests for proposals* for two 345/765-kV competitive transmission projects in Iowa.

The nearly $1.5 billion Marshalltown-Lehigh-Sub T-Montezuma-East Adair and the $1.23 billion East Adair-Minnesota/Iowa State Line-Arbor Hill-York Avenue projects hail from MISO's second, $22 billion long-range transmission portfolio. The two Iowa projects round out the seven projects that were eligible for competition from the portfolio.

Proposal deadlines for both occur in May; both projects are expected to be completed in 2034. ■

Questions Abound over MISO Idea for Zero-injection Gen Agreements

By Amanda Durish Cook

Stakeholders have several lingering questions as MISO continues to draw up a "zero-injection" avenue for large loads with planned on-site generation.

Marc Keyser, with MISO's external affairs team, said the RTO is looking to define and standardize the process, though it already maintains a few signed generator interconnection agreements with no electricity injection specified.

The RTO said in late 2025 that it would create interconnection agreements where generation dedicated to large load facilities is barred from injecting into its system. Those generation projects would be able to bypass the generator interconnection queue and interconnect in a matter of months, not years. (See *MISO Floats 'Zero Injection' Agreements to Bring Co-located Gen Online*.)

"We would like to make a filing soon. The first quarter is a great goal to have," Keyser said at a Planning Advisory Committee meeting Jan. 21.

MISO Director of Expansion Planning Jeanna Furnish added that the RTO would also continue to vet the proposal through its stakeholder process over spring.

"We understand that there are a lot of questions we have to work through," Furnish said.

Aerial view of Microsoft's Fairwater data center campus in Mount Pleasant, Wis. | *Microsoft*

The Bottom Line

Stakeholders said much remains unanswered regarding the proposed zero-injection interconnection agreements MISO hopes to introduce in the first half of 2026 to provide for large loads.

Keyser said a zero-injection agreement would restrict local generation to providing for its co-located load. He said the generation would be prohibited from running if the load isn't operating to accept it.

"It's potentially reducing network upgrades to interconnect," Keyser said of the arrangement that would get new generation on — and simultaneously keep it off — the system.

MISO's plan specifies that load can extract generation from the larger network if the generation isn't on, but its designated generation can never inject into the system from its point of interconnection.

But stakeholders still had questions about how MISO would prevent the netting of behind-the-meter generation with load, a practice FERC prohibits.

Keyser said MISO would require separate metering and telemetry data of the load and generation. "This is not an opportunity to net load and generation behind the meter," he said.

MISO Director of Resource Utilization Andy Witmeier said the process won't allow netting because the RTO will have full visibility into both the generation and load from a planning and operations perspective.

For studies, MISO said a zero-injection resource would be modeled the same as any other resource. It plans to study NERC contingencies and conduct reliability analysis, accounting for steady-state, voltage stability and dynamic stability.

"Broadly, our studies are designed to capture contingencies," Keyser said. However, MISO said reliability studies will always include scenarios where zero-injection resources are offline.

MISO said network upgrades wouldn't be needed for zero-injection resources even when the most severe contingency occurs and generation trips offline. Keyser said the studies would be designed to "quickly reflect" that load has sought its own generation.

Staff said MISO has struck zero-injection agreements for three unnamed customers so far, including chemical processing plants in MISO South.

"I wouldn't say this is readily available," Witmeier said of the arrangements. He said the process isn't documented in MISO's tariff or Business Practices Manuals.

Mississippi Public Service Commission consultant Bill Booth asked if the prohibition on generation injections would be voluntary or if MISO would require physical elements to prevent injection. "How can you rely on voluntary participation if you're not scanning the system for injections?" he asked.

Keyser said that of MISO's existing zero-injection agreements, some have equipment to bar injections while others have committed to not injecting.

Booth said barring an electric interlock, the RTO should deliberate on the difference between a voluntary promise not to inject and a guarantee to not inject.

The Sustainable FERC Project's Natalie McIntire asks what would happen if a large load supported by a dedicated generator tripped offline suddenly and the affiliated generator could not turn off output "really quickly."

"We know that we owe it to stakeholders to be more specific about what it means to be zero," Keyser said. "It's an important question. We do plan on addressing it."

He said MISO is holding conversations about operational reliability and is discussing elements such as how long it's appropriate for a 150-MW generator, for example, to churn out 151 MW.

"I just don't want MISO to gloss over all of these really technical questions as you're trying to develop this really quickly," McIntire said.

Arkansas Electric Cooperative Corp.'s David McRae said interrupting inertial generators can harm the generation. He asked how the RTO envisions dedicated generation ramping down over multiple cycles, if needed.

Keyser acknowledged that MISO has more work to do on those details as well.

At a Dec. 18 Organization of MISO States meeting, OMS counsel Brad Pope said the RTO's zero-injection plan could harbor some "real reliability concerns" if it isn't carefully thought out. OMS has scheduled a Jan. 23 meeting to discuss the proposal with RTO officials.

WEC Energy Group's Chris Plante said the no-netting rule should apply universally across all markets, including the capacity market. He asked how MISO would accredit generation dedicated solely to a single customer.

"I would encourage MISO not to design this behind closed doors and include stakeholders on the design," Plante said.

Booth said the RTO must figure out where the co-located load fits into a load-serving entity's obligation to serve. "We can't ignore it."

Anthony Alvarez, of the Iowa Office of Consumer Advocate, asked if the co-located load could become demand response or load-modifying resources.

Keyser said MISO will have to explore that more, but the large loads would be firm, full-rights load and other loads are entitled to become LMRs.

However, Keyser also said MISO would have to work out "what does demand response and market participation look like."

Wolverine Power Cooperative's Sawyer McClure said he didn't see why would-be zero-injection generation wouldn't just pursue retail behind-the-meter generation status to serve the large loads.

But Keyser said behind-the-meter status is meant for only generation connected at the distribution level.

"If the required connection is at the transmission level, that wouldn't work," Keyser said.

MISO said it would provide more details on its proposal at the PAC's meeting Feb. 25.

"This is not the extent of large load integration or 'helps' to incorporate large load," Keyser said of MISO's proposal.

Additionally, MISO will hold a workshop on how it plans to handle future large loads Jan. 30. ■

N.Y. Extends ZEC Nuclear Subsidies to 2049

Program Capped at $33.4B for Four Aging Constellation Reactors

By John Cropley

New York is *extending its nuclear power subsidies* as far as 2049 at a cost to ratepayers as high as $33.4 billion.

The four reactors and their 3.36 GW of output constitute an indispensable part of New York's power portfolio and decarbonization strategy, NYISO and various stakeholders have said.

They are expensive to operate, however, and not economical at market power prices.

The state in 2016 created the nation's first Zero-Emissions Credit (ZEC) program in recognition of these factors, and on Jan. 22, the Public Service Commission (PSC) extended the program's expiration date from 2029 to 2049 (case *15-E-0302*).

Constellation Energy, which operates all four reactors, has sought financial certainty as it plans the future of the two oldest operating reactors in the nation. They are licensed to operate only into 2029, and the deadlines to apply for their relicensing are March and June 2026.

"Failing to extend the ZEC program creates a risk of these plants closing, which could have significant impacts on reliability, resource adequacy and achievement of statewide clean-energy goals," PSC Chair Rory Christian *said in a news release*.

Later Jan. 22, Constellation said it was still reviewing the order and deferred comment.

The PSC had long been moving toward extension, and in a *July 2025 white paper*, its staff at the Department of Public Service laid out the justification for what is being called ZEC 2.0.

A broad range of commenters offered opinions in support or opposition for a broad range of reasons.

Many clean energy advocates in the state are particularly unhappy that the state is embracing nuclear rather than doubling down on renewable energy.

New York is a national leader in small-scale solar, but deployment of wind, large-scale solar and storage so far has not matched grand ambitions, and it is unlikely to get easier under President Donald Trump.

The four reactors are a combined 202 years old. But unlike the planned wind and solar farms, they are online now and they produce a lot of power — 21% of in-state generation and more than 40% of the state's emissions-free power.

Why This Matters

New York is continuing its embrace of nuclear energy as other grid decarbonization strategies lag.

New York state will continue subsidies for the Ginna Clean Energy Center and three other nuclear reactors operated by Constellation Energy. | *Constellation Energy*

NYISO reports that the reactors, with a combined nameplate capacity of 3.36 GW, generated 27,073 GWh in 2024.

The four reactors typically post annual capacity factors in the low- to mid-90% range and are steady except for refueling outages.

The output of New York's wind and solar installations varies noticeably by region and greatly by time of day or time of year. NYISO assigned a *capacity accreditation factor* of 10.5 to 12.24% to solar panels for the 2025/26 capability year and 16.61 to 18.2% for land-based wind, with exact amount depending on location.

Mixed Reactions

Meanwhile, the state's existing fossil generation is aging, the Trump administration is blocking offshore wind development, land-based renewables are slow and increasingly expensive to deploy, the governor's vision of new nuclear development may not become reality for a decade, and the dispatchable emissions-free resources state energy planners are counting on to backstop a carbon-free grid do not exist in scalable or economical form.

The existing nuclear reactors, therefore, are viewed as indispensable and, for now, irreplaceable.

In Oct. 20 comments submitted on the ZEC proceeding, NYISO wrote: "The existing fleet of four nuclear generation resources must remain operational to avoid resource adequacy shortfalls and other electric system reliability issues."

ZEC 1.0 cost $468.4 million to $600.5 million per year and $3.73 billion total *in its first seven years*.

ZEC 2.0 is capped at $33.4 billion, or

about $1.6 billion a year, but DPS staff said the actual cost to ratepayers is expected to be much less — perhaps more than 50% less — due to rising market revenue for the electricity they produce.

The costs to consumers resulting from retirement of the reactors would be greater, staff said.

ZEC 2.0 was modified to include contract performance requirements, a mechanism to reduce the payments if Constellation obtains other financial support, a four-year review process and other ratepayer safeguards.

The PSC vote was cheered by Carbon Free NY, a business-labor-environmental-community coalition that includes Constellation.

John Carlson of the Clean Air Task Force said: "The ZEC program supports more than 14,000 jobs across the state and prevents more than 16 million tons of carbon pollution each year, providing the foundation for a more affordable and cleaner grid for New Yorkers. We applaud the New York Public Service Commission for extending the ZEC program to preserve existing nuclear resources and bolster the program's tangible economic public health benefits."

Food & Water Watch decried what it called a massive corporate bailout — the largest single use of ratepayer dollars and the largest subsidy to a single company ever approved by the PSC.

"It's outrageous that New Yorkers will once again be forced to bail out this toxic, money-burning industry with billions and billions more in the coming years. Despite decades of evidence that nuclear power is both inherently dangerous and cost-foolish, Governor [Kathy] Hochul insists on throwing good money after bad, with everyday families footing the bill," said Food & Water Watch's New York state director, Laura Shindell.

The most recent nuclear reactor retirements in New York — Indian Point units 2 and 3 in 2020 and 2021 — resulted in a substantial increase in reliance on natural gas-fired generation.

NYISO reports 51.4% of the electricity generated in New York was produced with fossil fuels *in 2024*, compared with 39% *in 2019*, the last year of full operation for Indian Point. ■

FERC Addresses PJM's Ongoing RA Issues at Open Meeting

By James Downing

FERC held its regular open meeting Jan. 22, but much of the discussion focused on events at the White House and in PJM's headquarters a week earlier.

That's when the White House's National Energy Dominance Council and all 13 governors from PJM states agreed to call on the RTO to hold a separate backstop capacity auction for data center load, saying some hyperscalers had agreed to participate. (See *White House and PJM Governors Call for Backstop Capacity Auction*.)

"I want to recognize this historic agreement reached between the administration and a bipartisan coalition of 13 governors who represent the customers of PJM," FERC Chair Laura Swett said at the open meeting. "This is a monumental moment."

Later on the same day as the White House announcement, PJM released the proposals its board had been considering under the Critical Issue Fast Path (CIFP) process to deal with the influx of large loads in its footprint. (See *PJM Board of Managers Selects CFIP Proposal to Address Large Load Growth*.)

As a power pool, Swett noted, PJM is almost 100 years old and for most of that time has maintained a reliable grid, but now it faces "enormous challenges," as its load is growing and supply has lagged.

"The market rules of PJM drive decisions to finance, build and operate resources that are needed to support our country's reindustrialization and to win the AI race against our adversaries," Swett said. "We are at a crossroads of deciding critical issues to maintain national and economic security, but we need to ensure that hardworking Americans don't shoulder increasing energy bills."

Why This Matters

The PJM capacity market's rising prices and generation shortfalls have placed the RTO at the center of the dialogue around resource adequacy issues stemming from new large loads.

FERC holds its monthly open meeting Jan. 22. | *FERC*

The CIFP proposals and PJM's response to FERC's recent colocation order include many of the ideas the 13 governors and the White House called for in their statement, Swett said.

"I expect PJM will carefully consider its next steps, and FERC is ready to quickly evaluate any proposals that come before us," she added.

FERC also acted on rehearing proposals from MISO and SPP to speed up shovel-ready generation as they face their own issues around load growth and resource adequacy. Commissioner David Rosner noted the trend is national and other organized markets — or jurisdictional utilities outside them — face similar issues.

"The message I really want to underscore today is that other transmission providers, I hope, will take a look at what we did with PJM, and what SPP did for themselves, with their stakeholders, with very broad stakeholder support, and consider bringing similar ideas that work for your region," Rosner said. "And solve the problems that we need to solve, which is get new generation online fast, get large loads connected, and make sure we don't harm our reliability or raise costs for regular people."

Commissioner Lindsay See noted that it was rare to see all 13 governors in PJM — who represent states with very different politics — agree on a set of principles.

"As someone who used to work in state government for one of those 13 states, I can confirm that does not happen very often," the former West Virginia solicitor general added.

Commissioner Judy Chang noted that the issue of large loads is being addressed around the industry and said it was time to start thinking outside the box.

"Just generally, the supply challenge is tricky," Chang said. "And the great people at PJM are smart and hardworking, and I want to continue to recognize their efforts, both the leadership and the stakeholder community, to continue again to address the challenges and put on their problem-solving hats to address the issues in the Mid-Atlantic region. I know that PJM staff is working hard to address the supply crunch in a very complicated and really difficult environment with very few quick fixes, or very few easy or obvious solutions."

Continued from page 43

Government-proposed 'Backstop' Auction to Test PJM Stakeholder Process

By Devin Leith-Yessian

PJM stakeholders Jan. 22 kicked off discussions on creating a "backstop" auction to be held in September at the insistence of the Trump administration and the governors of the RTO's 13 states.

The Members Committee discussed the feasibility of holding such an auction and how the logistics of creating the rules for doing so should be balanced with other elements of the Critical Issue Fast Path (CIFP) *proposal* the Board of Managers selected for addressing large load growth Jan. 16.

The White House's National Energy Dominance Council (NEDC) and state governors, issued the same day as the board announced its choice, envisions a one-time auction that procures new resources for a 15-year commitment period. (See *White House and PJM Governors Call for Backstop Capacity Auction*.)

"The PJM board should file tariff revisions expeditiously, as PJM has already received stakeholder input through the 2025 [CIFP] process, and no further CIFP processes are necessary," they said in a *statement of principles*.

In its announcement of its CIFP proposal choice, the board said the RTO's existing backstop capacity procurement method should be accelerated: It is currently triggered only after three consecutive capacity auctions fall short of the reliability requirement. (See *PJM Board of Managers Selects CIFP Proposal to Address Large Load Growth*.)

PJM Board of Managers Chair David Mills speaks during the Jan. 22 Members Committee meeting. | © RTO Insider

"Accelerating a backstop capacity procurement is especially necessary in light of FERC's recent decision on co-location and its request for more information on utilization of this backstop procurement framework," it said in a *letter* to stakeholders.

Addressing the MC on Jan. 22, board Chair and interim CEO David Mills said both the government's and the board's proposals don't bear any resemblance to the existing backstop. PJM's load forecast shows data center demand is likely to rise for a significant amount of time. "A one-time auction is not going to scratch the itch completely," he said.

Designing an auction able to provide certainty for the supply and demand side of the auction on that timeline will require the states and FERC to be involved and take ownership over the outcome, Mills said. What can't be allowed to happen is for there to be extended fruitful discussions only for an uninvolved party to fire a flare in the final hours, he said.

Even with a backstop auction, Mills said there are significant barriers to getting new resources built, including transmission upgrades, financing, tariffs, siting, permitting and supply chain constraints. Significant new capacity is unlikely to be available until 2032.

Manager Vickie VanZandt said the challenges of siting transmission could impede any resource adequacy benefits a backstop auction might provide. States and transmission owners will have to work together to overcome the likelihood of immense public pushback against network upgrades required to make new resources procured through a backstop deliverable.

Pennsylvania Deputy Secretary of Policy Jacob Finkel said he could not underscore the gravity of a bipartisan group of 13 governors and the White House calling on PJM to conduct the auction. He pushed back against suggestions that the September deadline was meant to be before the midterm elections in November, saying nine months seemed to be workable.

"We want this RTO to work; we want to solve this problem, but changes have to occur," he said.

Why This Matters

The discussion was the beginning of what will be a frantic process to create and hold an entirely new auction in less than nine months.

Constellation Energy Vice President of Wholesale Market Development Adrien Ford said the feasibility of holding a backstop auction in September depends on the design PJM decides to adopt and whether it tries to build off the existing capacity product or define a new one.

She said Constellation has been working with Vistra to revise the backstop mechanism that a coalition of resource owners and data center developers proposed during the CIFP process that would build off the existing definition of capacity, triggering if a capacity auction cleared below 98% of the reliability requirement and allowing for up to seven-year commitments. The auction would be open to new or reactivated resources; existing resources with offers higher than the maximum price for the Base Residual Auction that cleared short; and traditional demand response. (See "Joint Stakeholder Proposal," *PJM Stakeholders to Vote on Large Load CIFP Proposals*.)

Mills said his vision of success is a ready-to-launch mechanism that accomplishes what PJM has been asked to do: Establish a market mechanism that marries new committed demand to new supply. To get to that point, stakeholders will need to chew through a lot of details, but he said that's within their capability. He said he believes that in four to six weeks, there will be great progress on creating a workable design.

Unintended Consequences

Mills also called for stakeholders to identify areas where unintended consequences could be created by running auctions to procure capacity outside

BRAs. One such challenge could be the creation of an additional cycle of grid upgrades being triggered.

The PJM Public Power Coalition's Carl Johnson warned that a parallel capacity auction with the potential to deliver higher value for sellers could cannibalize projects already in the interconnection queue. If a substantial number of planned resources that PJM expected to come online and offer into the Reliability Pricing Model instead seek to participate in a backstop auction, there would be no net change in the amount of supply available to the grid, and the market would be even more short.

The Natural Resources Defense Council's Claire Lang-Ree said the success of the backstop auction relies on the other components of the board's CIFP proposal. If the bring your own new generation (BYONG) and "Connect and Manage" DR pathways for data centers aren't strong enough, she said it would be hard to see why they would want to participate in a potentially more expensive backstop auction.

The BYONG model would allow large loads to meet their own capacity needs with new resources, which would qualify for an expedited interconnection track. Large loads that do not participate in BYONG would be subject to curtailment through load-serving entities ahead of pre-emergency load management resources in a model similar to PJM's proposed mandatory non-capacity backed load (NCBL) brought during CIFP — though the load would remain in the capacity market. (See *PJM Revises Non-capacity Backed Load Proposal*.)

Mills said those changes are another area that will require buy-in from states to be successful: Because PJM cannot distinguish between consumers directly, it will be up to state utility commissions and utilities to disentangle large loads from organic economic growth.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said he is concerned an auction awarding multiyear commitments would shift risk onto consumers.

Consumer advocates and representatives of Pennsylvania Gov. Josh Shapiro's office urged PJM to extend the price collar that limited capacity prices to between \$175 and \$325/MW-day for the 2026/27 and 2027/28 auctions. Finkel said the 2028/29 BRA is not going to be able to procure enough supply and will clear at the \$550/MW-day maximum price, a jump in prices he argued would not come with any reliability benefit. (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.)

Paul Sotkiewicz, president of E-Cubed Policy Associates, said constraining capacity prices would ensure that a parallel backstop auction would cannibalize resources from RPM. ■

FERC Addresses PJM's Ongoing RA Issues at Open Meeting

Continued from page 41

'Necessary Partners'

Commissioner David LaCerte said FERC will hopefully have a package of capacity reforms from PJM in front of it soon, and like the other four commissioners, he noted the commission a day earlier had issued an order approving the RTO's changes to the reliability pricing model (RPM) based on its most recent quadrennial review (*ER26-455*).

PJM must update its variable resource Requirement (VRR) curve every four years, including major inputs like the gross cost of new entry (CONE) and the expected energy and ancillary services (EAS) net revenues offset.

In the order, FERC accepted a combustion turbine plant as the reference resource for the 2028/29 delivery year and beyond. The peaker plants get most of their revenue from the capacity market, making it easier to calculate the EAS.

"A more accurate and stable EAS offset, in turn, results in a more accurate and stable VRR curve, which provides load and capacity suppliers with greater confidence in capacity auction prices," the order said.

FERC also approved the shape of the VRR curve PJM proposed, which faced protests from the RTO's Independent Market Monitor and Maryland's Office of People's Counsel because it discounted the EAS offset by 25%. PJM did that to hedge against the risk of overestimating the EAS and thus underestimating net CONE.

"PJM explains that even though it has historically hedged against this same risk by inflating the price cap by a certain percentage, its proposal to inflate gross CONE and deflate the EAS offset achieves the same effect," the order said. "In addition, PJM correctly notes that capacity market prices should be able to rise above Net CONE during tight market conditions such that the price averages net CONE in the long term."

FERC also accepted the RTO's proposals for net CONE and the EAS offset. The order drew a concurrence from Rosner who pointed out states are an important part of resource adequacy in PJM.

"Given states' authority over siting generation and transmission, public utility commissioners, governors' offices and state legislatures are all necessary partners in any effort to ensure energy infrastructure is built out at the pace needed to stay ahead of load growth and keep energy affordable and reliable for PJM customers," Rosner wrote.

"Just as PJM must earn buy-in from its states and its members to achieve durable market rules, we depend on PJM states, load-serving entities and developers to take the financing, procurement, permitting and construction steps needed to turn PJM market signals into steel in the ground. The PJM market is intended to support these efforts — not supplant them," he wrote. ■

New N.J. Governor Rapidly Confronts Electricity Crisis

Executive Orders Outline Solar, Storage and Gas Strategies to Control Rates

By Hugh R. Morley

Taking office on Jan. 20, New Jersey Gov. Mikie Sherrill (D) immediately signed two sweeping executive orders that sought to control the state's aggressively rising electricity rates through ratepayer credits and generation expansion.

The governor outlined plans to use funds from the Regional Greenhouse Gas Initiative and two other sources to provide ratepayer credits. The directives also aim to increase generation capacity by accelerating solar and storage development; better manage peak loads by creating a virtual power plant; and enhance the production of existing gas generators by improving efficiency.

At a morning swearing-in ceremony in Newark, Sherrill said she would be "fighting for" the people of the state and turned to the state's power challenges as an example. During the election, Sherrill made affordability a central element of her campaign and pledged to take on the state's increasing electricity prices with a rate freeze upon taking office. The average rate bill in the state rose by 20% in June. (See *N.J. Backs Clean Energy Democrat for Governor*.)

"I hope, New Jersey, you remember me when you open your electric bill and it hasn't gone up another 20%," she said. "I can promise you, it won't be because I waste your money on a ballroom at Drumthwacket," she said, referring to the governor's mansion.

Sherrill's proposals drew a warm reception from environmental groups, and the New Jersey Business and Industry Association said it is "encouraged to see that Gov. Sherrill is taking on the energy affordability and reliability issues head on."

"Energy policy needs to be grounded in realism, and these executive orders recognize the issues and set forth potential solutions," said Ray Cantor, a lobbyist for the organization. "They are very positive."

He added that it is hard to "predict the ultimate impact" of the orders, but they lay the "groundwork" for future actions.

Abe Silverman, a former counsel for the New Jersey Board of Public Utilities who is now an assistant research scholar at Johns Hopkins University in Baltimore, said the breadth and depth of the two EOs show the importance of the issue to the state and to Sherrill.

Why This Matters

New Jersey has some of the highest electricity rates in the U.S., and Sherrill's orders indicate that she intends to make addressing them a priority.

"The fact that the first two EOs of a new administration are about energy affordability — that sends a pretty loud signal to the world that this is a priority," Silverman said.

He said he was impressed that the EOs contained a significant number of "meaty," concrete and realistic proposals, in addition to longer-term strategies such as paying utilities based on performance rather than a percentage of capital spent.

"I would give it very high marks for viability. I would give it very high marks for the ability to dent any cost increases," he said of the plan outlined in the two EOs. "I think we have to give it a bit of an incomplete on whether they'll be able to implement a rate freeze, because we simply don't know how big the cost increases on the PJM system are going to be."

Rate Cost Offsets

Sherrill's first *order* directs the BPU to create Residential Universal Bill Credits to "offset increases in the cost of electricity supply due to take effect in 2026."

The order says funding for the credit would come from RGGI, the state Societal Benefits Charge and the state Solar Alternative Compliance Payment account. Similar sources funded a $100 credit to the state's 3.9 million residential ratepayers announced in August to mitigate the June rate hike.

The order also requires the BPU to conduct a "study regarding modernization of the traditional distribution utility business model" and to look for ways to increase support for energy efficiency programs for low-income ratepayers. It directs the BPU to "consider pursuing a pause, abeyance or modification of the schedule governing any proceedings in which electric distribution utilities seek approvals for rate increases or cost recoveries to the extent permitted by law."

"The current cost of electricity has reached the point of crisis for many residents and families, and requires bold action to provide short-term relief and medium- and long-term strategies and reforms to improve our energy system," the order says. It adds that electricity rates in New Jersey are "among the highest in the continental United States and in the Mid-Atlantic region."

Boosting Solar, Gas Generation

The second *order* calls for a push to develop more solar and storage, saying their shorter development timelines — "often months rather than years — makes them particularly critical technologies to meeting the state's and the region's electricity supply."

The order requires the BPU to accelerate solar generation with a new solicitation for grid-scale solar under the existing Competitive Solar Incentive and an offering of 3,000 MW of generation under the Community Solar Program. An existing storage incentive program will launch a solicitation for "transmission-scale" battery storage.

The order also requires the BPU to develop a VPP that it says will "drive down peak demand by aggregating behind-the-meter distributed energy resources."

Sherrill also called on the BPU to investigate ways to reduce or expedite the state permitting process, including for existing gas-fired power plants, in a modernization effort that should "increase generation capacity, reduce emissions and improve efficiency."

Her order also requires utility companies to prepare a report on ways to "improve the efficiency and speed of interconnec-

Gov. Mikie Sherrill | *Gov. Mikie Sherrill via X*

tion of new projects." And it calls for the creation of a Nuclear Power Task Force to "formulate and implement a strategy for the development of new nuclear generation facilities in the state."

Rapid Demand Escalation

Sherrill succeeds fellow Democrat Phil Murphy, who has faced criticism that he focused too much on clean energy in his two terms and left the state short of generating sources.

But New Jersey officials say after two decades of flat demand, they could not have predicted the sudden demand surge from data centers.

PJM says the state's difficulties echo those throughout its service region, where politically driven decisions by the states mean old, mainly fossil-fuel generators have closed at a faster rate than replacements have come online. That dynamic has been dramatically worsened by the sudden appearance of demand from heavy energy-using data centers, the RTO says.

In the first order, Sherrill attributes the state's rising electricity prices to "the escalating cost of transmission and distribution infrastructure on which the grid relies, volatility in the price of natural gas and the skyrocketing price of the future supply of reliable, wholesale electricity — also known as capacity — in the regional PJM market."

New Jersey's task of needing to speedily build capacity is especially difficult. The centerpiece of Murphy's energy plan — 11 GW of offshore wind generation — has largely stalled. The developers of the state's most advanced projects, Ocean Wind and Atlantic Shores, withdrew as rising project costs threatened their economic feasibility, and the Trump administration has sought to shut down wind projects. The state currently has no active wind project.

The impact of Sherrill's measures on the state's rate woes, and generation shortfall, is unclear.

Lyle Rawlings, president of the Mid-Atlantic Solar & Storage Industries Association and a solar developer, said "there is a lot of good stuff" in the two orders. That includes the effort to accelerate the development of solar and storage projects, the VPP and a grid modernization plan, he said.

Still, he questioned whether the state could handle an increase of 3,000 MW in the community solar program, calling it an "enormous amount" and adding that its implementation could cause "some chaos." He was skeptical that the state could connect that capacity so quickly to the grid.

But the biggest drawback in Sherrill's proposal is the lack of "emphasis given to reform of PJM, which we think is the only thing that is going to bring prices back down or stabilize them in the near term," he said. "The primary focus needs to shift to that, or else there's no way that any other measures will be effective."

But environmental groups had few doubts about Sherrill's proposals.

Anjuli Ramos-Busot, director of the Sierra Club's New Jersey chapter, said the two orders would "will freeze electric rates and put more clean, cheap energy generation on the ground."

Jackson Morris, director of state power policy at the Natural Resources Defense Council, said his organization is "confident those important deliberations will result in a robust energy portfolio that maximizes renewables and energy efficiency for the benefit of all ratepayers." ■

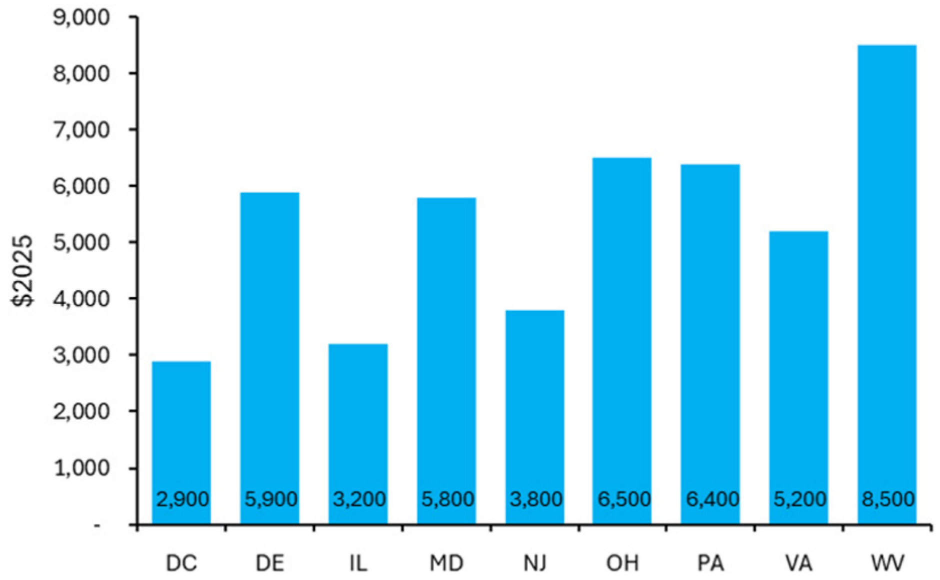
ACP: Slow Renewable Development in PJM Could Cost Ratepayers $360B

By Devin Leith-Yessian

A *report* from the American Clean Power Association (ACP) argues that slowing down renewable development in PJM could cost ratepayers $360 billion over the next decade.

The analysis, released Jan. 21, compared a base case assuming wind, solar and storage development follows current expectations and reaches 137 GW of nameplate capacity by 2035 with a scenario in which only projects already under construction or legally mandated are built. With the amount of growth expected in PJM's 2025 Load Forecast, the report finds that without that renewable buildout, the RTO will increasingly rely on aging fossil fuel resources and imports, dispatching of which would increase by 20% and 292%, respectively.

West Virginia would see the largest residential rate increase over the next decade at $8,500 for a typical customer, followed by Ohio and Pennsylvania at $6,500 and $6,400. Illinois and D.C. would be lowest at $3,200 and $2,900.



The expected cost increases for ratepayers in PJM states if renewable energy programs are cut | *American Clean Power Association*

"These findings make clear that delaying clean energy deployment comes at a steep cost," Senior Vice President of Markets and Policy Analysis John Hensley said in a *statement*. "Timely investment in wind, solar and energy storage is essential to maintaining reliability, reducing dependence on imports, and protecting families and businesses from sharply higher electricity bills as demand continues to grow."

Hensley told *RTO Insider* the impact of a slowdown in renewable development would come in three areas: rising rates, diminished reliability, and the economic impact of data centers and manufacturing facilities siting outside of PJM as a result.

While 50 GW of new gas generation are included in the analysis, the report says that efforts to push for more resources would quickly lead to higher costs so long as turbine availability remains constrained.

"This reliance on imports and gas peaking units increases exposure to fuel price volatility, drives more high-priced hours, and heightens reliability risks during peak demand periods," the report says.

Hensley told *RTO Insider* he views gas as playing a role in meeting the reliability challenges posed by rapid load growth in the coming years, but there is a timing disconnect with how long those resources take to construct. Renewables have strong supply chains allowing for rapid construction.

He said the starting point for efforts to bring more generation online should be a non-discriminatory approach that recognizes the contributions of all technologies. He pointed to PJM's effective load-carrying capability model for determining the capacity contribution for different resource classes.

The No Clean Power scenario assumes states end their renewable portfolio standards and no renewable energy credits are available, while the base case includes tax credits being available in full for wind and solar through 2030 and for storage through 2032. Hensley said the base case assumptions about renewable development were based on projects in PJM's interconnection queue, an ACP database of renewable projects, Energy Information Administration data and projections from organizations such as Bloomberg and S&P Global.

PJM's 2026 Load Forecast tamped down the expected growth over the next five years, though peaks are still expected to increase from 160 GW in 2027 to 191 GW by 2031. By 2046 the summer peak is expected to reach 253 GW. (See *Pessimistic PJM Slightly Decreases Load Forecast*.)

The RTO's two transition cycle queues include 1,669 MW of wind, 7,051 MW of storage, 17,075 MW of solar, 1,503 MW of nuclear and 5,460 MW of gas, according to its planning *webpage*. There are 27,537 MW of solar under construction, as well as 3,876 MW of storage, 8,059 MW of wind, 5,796 MW of gas and 2,930 MW of hybrid resources.

PJM did not respond to a request for comment. ■

PJM Stakeholders Endorse 2026/27 Third Incremental Auction Parameters

By Devin Leith-Yessian

The PJM Markets and Reliability Committee and Members Committee endorsed the RTO's *recommended* installed reserve margin (IRM) and forecast pool requirement (FPR) for the third 2026/27 Incremental Auction, scheduled to be conducted Feb. 24.

The vote is advisory to the Board of Managers, which determines the values to be used in the auction.

The IRM would fall from the 19.1% used in the 2026/27 Base Residual Auction to 18.6%, while the FPR would increase from 0.9170 to 0.9291. (See "Stakeholders Endorse IRM and FPR for 2026/27 Capacity Auction," *PJM MRC/MC Briefs: March 19, 2025*.)

Patricio Rocha Garrido, PJM | © *RTO Insider*

The inputs for the parameters were based on the 2026 load forecast, which predicted lower load in the long term and shifted the concentration of reliability risk toward the summer, though the majority still lies in the winter at a 55.9% loss-of-load expectation. (See *Pessimistic PJM Slightly Decreases Load Forecast*.)

Most resource classes would see a modest increase in their effective load-carrying capability (ELCC) ratings, with four-hour storage resources seeing the largest benefit, going from 50 to 54%. Owing to its stronger winter performance, offshore wind generation would see a decrease from 69 to 64% and onshore wind from 41 to 38%.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the influence load has on the amount of supply that resources can offer creates a dynamic that runs contrary to economic logic. The volatility of class ratings undermines the ability for investors to make sound decisions, particularly because the control they have over their assets' ratings is limited. Pointing to the contributions solar made in maintaining reliability during the heat waves of summer 2025, he argued ELCC is making the RTO look shorter than it is.

"This calls into question the validity of PJM's ELCC model because if we see load decreases continue in the future … as the load increases, capacity accreditation falls and the IRM goes up," he said.

PJM's Patricio Rocha Garrido said the relationship between load uncertainty and the IRM has always been present, including under the previous PRISM modeling software.

"What we're trying to do here is determine what are the risk hours" and determine resource performance at those times, he said, adding that was also the goal under the equivalent forced outage rate demand (EFORd) accreditation paradigm.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said several consumer advocates will abstain from votes on the IRM and FPR values because it seems stakeholders have little sway on the values the RTO is proposing. He said staff put in good work developing the values, but if it's going to be more than a check-the-box exercise for stakeholders, there needs to be more of a process around how the numbers are produced and presented.

Responding to stakeholder questions on what the vote means to the board, PJM Senior Vice President of Market Services Adam Keech said he views the vote as pertaining to whether staff followed the process for determining the IRM and FPR values. If stakeholders feel those processes should be revised, that should be pursued through a separate process. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Definition of Offline Secondary Reserves

PJM's Suzanne Coyne presented the RTO's Markets and Reliability Committee with revisions to Manual 28: Operating Agreement Accounting to clarify how resources are defined as offline for the purpose of determining whether they are eligible for lost opportunity cost (LOC) credits. (See "Stakeholders Endorse Quick Fix on Offline Resource LOC Eligibility," *PJM MIC Briefs: Jan. 7, 2026*.)

Coyne said that while the governing documents state that resources that are offline when committed for secondary reserves are not eligible for LOC credits, the manual language can result in resources improperly being considered online if they begin operations between when they are dispatched and when the commitment begins.

The market clearing software has visibility into whether a resource is offline when it assigns a commitment; however, the settlement calculations consider only whether a unit is online when the commitment interval begins 10 minutes later.

The proposal would use real-time security-constrained economic dispatch data to determine whether a resource is online, unifying the discrepancy between dispatch and settlement, she said. If endorsed by the MRC in February, the language would be implemented March 1.

Must-offer Requirement for Self-Scheduling Resources

Mike Cocco, of Old Dominion Electric Cooperative (ODEC), presented a quick-fix proposal to define a capacity resource as having met its obligation to offer into the energy market if it self-schedules and provides its full output.

The quick-fix process allows a problem statement and issue charge to be brought concurrently with a proposed solution.

Cocco said the proposal would ensure that gas generation resources that self-schedule to ensure they are able to operate and consume fuel procured on ratable take contracts are not at risk of non-performance penalties if there is a

PJM Markets and Reliability Committee Chair Dave Anders | © *RTO Insider*

performance assessment interval. Cocco said that all the parties he has reached out to, including PJM and the Independent Market Monitor, have said they interpret Manual 11: Energy & Ancillary Services Market Operations as already providing that protection, but he said ODEC believes that should be codified in the language.

PJM Senior Vice President of Market Services Adam Keech said the parameter-limited schedule (PLS) process is intended to cover these circumstances and questioned whether the proposal is meant to complement or replace that. When a resource owner seeks a PLS exception, it must meet a higher burden of proof that it has diminished flexibility because of the ratable take.

Cocco responded that the proposal as envisioned would not require generation owners to obtain PLS exceptions, but he wanted to consider the comment further and would reach out to PJM staff to discuss.

Members Committee

Stakeholders Endorse Minimum Capitalization Changes

PJM's Members Committee endorsed by acclamation a proposal to increase the minimum capitalization requirements for participating in the RTO's markets. (See *PJM Presents 1st Read on Minimum Capitalization Requirement Proposal*.)

The proposal would revise the tariff to double the tangible net worth requirement to $2 million for those participating in financial transmission rights markets. For entities not participating in FTR markets, there would be a transition period in which the requirement would first increase from the current $500,000 to $1 million and then increase by $200,000 annually over five years. The proposal also adds a 3% fixed annual escalator.

The proposal would not change the alternative tangible asset threshold of $10 million for FTR participants and $5 million for non-FTR participants.

Consumer Advocates Form Residential Affordability User Group

New Jersey Division of Rate Counsel Director Brian Lipman announced the creation of an Affordability and Reliability for Residential Consumers User Group intended to reduce the impact on ratepayers of accelerating load growth from data centers.

Along with his agency, Lipman said the user group includes the Delaware Division of the Public Advocate, D.C. Office of the People's Counsel, Illinois Citizens Utility Board, Maryland Office of People's Counsel, Office of the Ohio Consumers' Counsel and the Pennsylvania Office of Consumer Advocate.

Lipman said the group's first meeting on Jan. 27 will include voting on the draft charter and the concept of revising governing documents to include affordability in PJM's mission statement and Operating Agreement.

Vitol's Jason Barker said he appreciated the goal of the user group, and while his company has no position on whether it should be formed, he objected to the announcement stating that consumer advocates only have 1% of the voting power in lower standing committees.

Barker said that when sector-weighted voting is accounted for in the MRC and MC, consumer advocates can have the power to sway votes. He pointed to the Critical Issue Fast Path process conducted in 2025 on large load growth, in which 10 consumer advocates cast votes that accounted for half the end-use customer sector, meaning those offices held 10% of the sector-weighted vote.

The 1% figure references the diluted voting power consumer advocates hold outside the MRC and MC, where each of PJM's 1,111 members can cast votes.

Barker said it is typical for only about 10% of those members to vote in the lower committees. ■

— Devin Leith-Yessian

Colo. PUC Sticks with Approval of Markets+ for PSCo

Regulators Backtrack on Early Filing Deadline for RTO Participation

By Elaine Goodman

Colorado regulators have declined to reconsider their decision finding that it would be in the public interest for Public Service Company of Colorado (PSCo) to join SPP's Markets+.

The Colorado Public Utilities Commission voted 2-1 on Jan. 21 to deny requests by three organizations for rehearing, re-argument or reconsideration. As in the initial *decision*, issued Oct. 9, Chair Eric Blank and Commissioner Tom Plant voted in favor, while Commissioner Megan Gilman was opposed. (See *Split Colo. PUC Approves Xcel Energy's Markets+ Application* and *Colo. PUC Approves PSCo's Markets+ Participation*.)

The requests for reconsideration came from Western Resource Advocates, Advanced Energy United and Colorado Energy Consumers.

"After reviewing the [requests] filed by WRA, AEU and CEC, I still find that the majority's initial decision is sufficiently supported within the record and based on policy considerations," Blank said.

But the commission did agree to reverse its decision to direct PSCo to file an application to join an RTO or ISO, or request a waiver from doing so, by June 1, 2027 — two years earlier than the deadline set in commission rules.

State law requires electric utilities that own and control transmission facilities to join an organized wholesale market (OWM) by 2030. In its original decision, the commission had argued there was "a genuine potential for Public Service to conclude its efforts in organized wholesale market participation with SPP Markets+." The earlier deadline would "help confirm that Public Service is moving towards its eventual participation in an OWM or is prepared to show why OWM participation is not in the public interest."

But AEU argued in its reconsideration request that the earlier deadline would dramatically increase the odds that PSCo, an Xcel Energy subsidiary, would seek a waiver from RTO or ISO participation and that the waiver would be granted. Fewer data about the benefits of SPP's RTO West, also known as the RTO Expansion, would be available then, AEU said, and alternatives available through the West-Wide Governance Pathways Initiative would likely be at an early stage.

Commissioners agreed and reset the deadline to June 1, 2029.

In another change to its earlier decision, the commission addressed concerns that PSCo would use the money spent on joining Markets+ as an argument against RTO participation. The commission directed PSCo to exclude sunk costs in the cost-benefit analysis of joining an RTO.

| JIRSA Hedrick

Why This Matters

The commission's decision keeps PSCo on track to begin Markets+ participation in 2027.

Public Interest Finding

Under commission regulations, transmission utilities that want to participate in a day-ahead market must demonstrate three things: The market must have protocols in place for greenhouse gas emissions tracking and accounting; it must have a plan to address seams issues with neighboring markets; and the expected benefits of joining the market must exceed costs, as shown by modeling and other analysis.

Parties that sought reconsideration said the GHG protocols and seams strategies for Markets+ are not fully developed. They said a Western Markets Exploratory Group study that analyzed costs and benefits was based on "flawed assumptions and outdated market footprint."

WRA argued that the commission "should not make a public interest determination before requiring the company to evaluate participation in other markets," including CAISO's Extended Day Ahead Market.

Blank pointed to a previous commission determination that utility participation in an energy imbalance market, a day-ahead market, an RTO, a power pool or a joint tariff is generally in the public interest. The determination was based on a study commissioned to meet requirements of the Colorado Transmission Coordination Act of 2019.

But Gilman sided with the groups requesting reconsideration. She said she plans to again write a dissent to the commission's decision.

"Plain and simple, the company failed to provide the evidence that met the public interest requirement in the rules," she said. ■

FERC Dismisses Rehearing Ask for SPP's ERAS Process

Commission Accepts RTO's Order 2023 Compliance, FCA Tariff Revisions

By Tom Kleckner

SPP headquarters | *Ace Glass*

FERC has rejected a rehearing request of its order approving SPP's proposed one-time accelerated study of shovel-ready interconnection requests, sustaining its original 2025 decision (*ER25-2296*).

Clean energy groups and public interest organizations — including the Advanced Power Alliance, American Clean Power Association, Natural Resources Defense Council and Sierra Club — opposed the Expedited Resource Adequacy Study (ERAS) during the stakeholder process, arguing that it amounts to queue jumping, bypasses open access to the RTO and violates FERC's principle of nondiscriminatory access to the grid.

The organizations filed for rehearing in August, one month after FERC's order. They contended the commission's decision was arbitrary and capricious because it was based on unexplained assumptions that little to none of the capacity being studied in SPP's current interconnection process will be available to serve near-term resource adequacy needs.

The groups called the assumptions "implausible," noting that the RTO assumed none of the 4,500 MW of summer-accredited capacity in a 2022 study cluster will be available to meet 2030 needs; only 418 MW of over 31,000 MW of energy storage in the queue will meet 2030 resource adequacy needs; and no capacity from the 2024 study cluster will be available in 2030.

They said the grid operator has projected in other forums that 40% of the generation in the queue will come online, "inconsistent with SPP's assumptions," and that it did not discount future load growth to reflect historical rates.

FERC disagreed. In an order issued at its monthly open meeting Jan. 22, said SPP had met its burden to show that the ERAS process is just and reasonable and supports near-term resource adequacy needs.

"A number of well documented factors are contributing to what SPP has characterized as a looming resource adequacy crisis," the commission said. It noted SPP "expects" available capacity to drop below reserve margins by 2027 and for the region to have insufficient capacity to meet peak demand in 2030.

"SPP further [predicts] that, within the next two to five years, [load-responsible entities] will be unable to meet their state-mandated obligation to serve load" and the tariff's resource adequacy requirements, FERC said, pointing to the RTO's projections that an additional 16.7 GW of accredited capacity will be needed by 2030.

The RTO has 552 active interconnection requests in its *queue* for more than 130 GW of capacity. It told FERC that given proposed commercial operation dates, historical withdrawal rates and capacity accreditation rates, "actual capacity to meet SPP's near-term resource adequacy needs was likely to be far more limited" and that its current interconnection process could not meet expected needs.

The commission also rejected open-access arguments, saying ERAS interconnection requests are "necessarily subject" to SPP's more stringent criteria for eligibility.

"ERAS interconnection customers are differently situated than interconnection customers that do not meet these criteria," FERC said, "in their expected ability to achieve commercial operation more quickly to participate in this one-time process to respond to the near-term needs of particular LREs that SPP has determined are expected to face a capacity deficiency."

In approving the ERAS process in July 2025, FERC found that SPP had "existing authority" under its tariff to evaluate and maintain resource adequacy and to manage its interconnection queue in providing sufficient generation to meet RA requirements. (See *FERC Approves SPP's ERAS Process, Accreditation*.)

Order 2023 Compliance Accepted

In a separate order issued during the meeting, FERC accepted SPP's second compliance filing with the requirements of Orders 2023 and 2023-A (*ER24-2026*).

In partly accepting SPP's first compliance filing in June 2025, the commission found that its proposed tariff revisions amending FERC's *pro forma* large generator interconnection procedures (LGIP) and generator interconnection agreements partly complied with the order. (See *FERC Partly Accepts SPP's Order 2023 Compliance*.)

It found SPP followed its subsequent directives by proposing to adopt, without modification, the *pro forma* LGIP requirement that an affected system restudy be completed within 60 calendar days from the restudy need's date. The commission also said the grid operator complied by removing language from the *pro forma* LGIP requiring interconnection customers to submit a deposit with each request, even when more than one request is submitted for a single site.

FERC issued Order 2023 in July 2023 in an effort to clear backlogged interconnection queues by implementing a first-ready, first-served cluster study process; increasing interconnection customers' financial obligations; and penalizing grid operators for missing study deadlines. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

In 2024, the commission rejected challenges to the interconnection rules under Order 2023 and made several clarifications, minor modifications and an extended compliance deadline with Order 2023-A. (See *FERC Upholds, Clarifies Generator Interconnection Rule*.)

FERC Releases Letter Orders

In a Jan. 20 letter order, FERC accepted SPP's proposed tariff revisions modifying language related to the local market power test for resources in frequently constrained areas (FCAs) (*ER25-3331*).

The revision, with an effective date of Jan. 26, prohibits market participants from nominating and acquiring — and portfolios from containing — certain auction revenue rights and transmission congestion rights (TCRs) that source and sink in electrically equivalent settlement location groups.

SPP's Market Monitoring Unit supported SPP's proposal, saying it "more clearly define[s] the full scope of trades that are not permissible in SPP's TCR market."

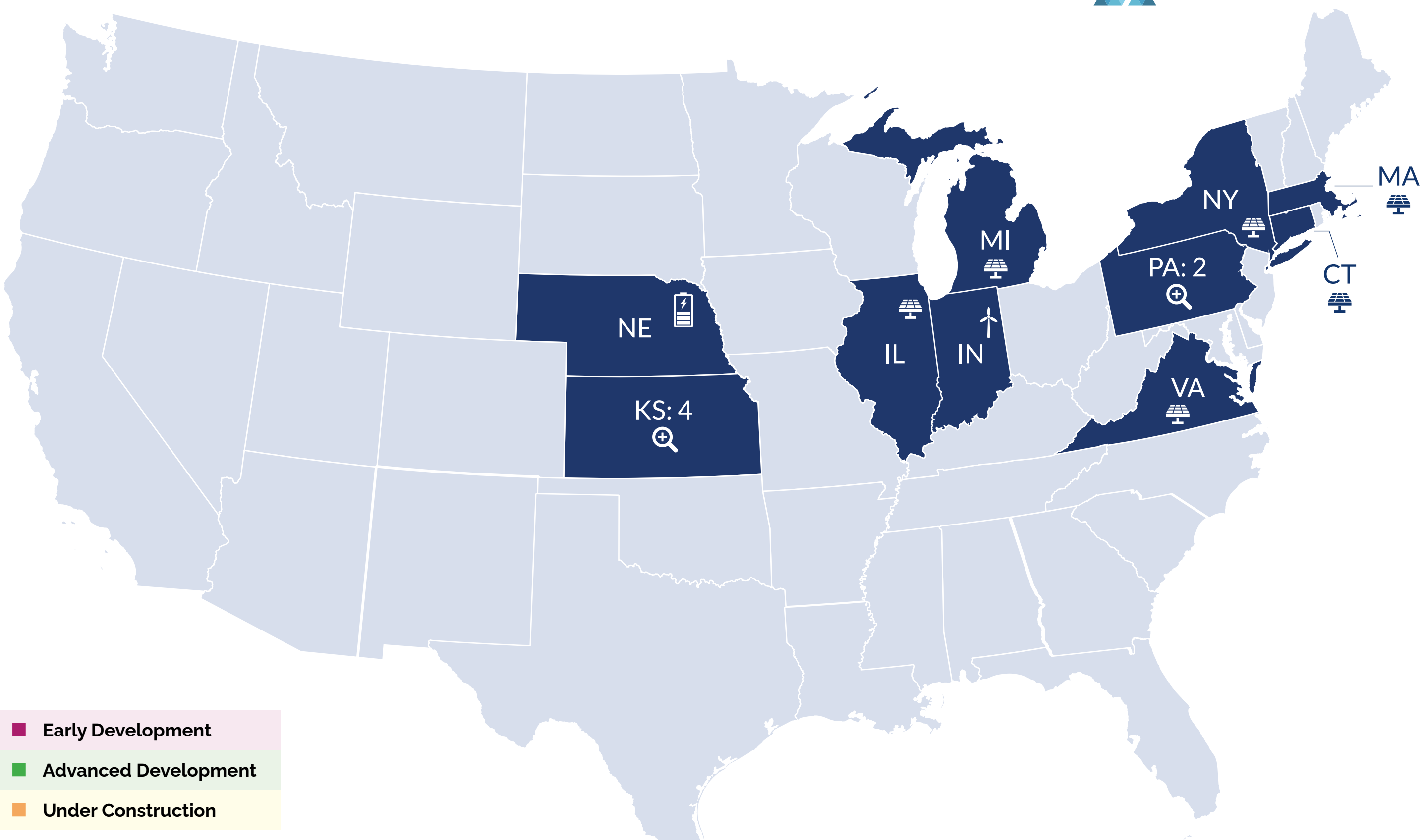
The commission directed SPP to submit a compliance filing within 30 days of the order's date.

In another Jan. 20 letter order, FERC approved the RTO's proposal to modify language setting the conditions under which a resource is determined to have local market power (*ER26-562*).

The commission found it reasonable for resources within an FCA to undergo the same level of scrutiny as resources outside the area when testing for local market power with respect to constraints outside the FCA. It said SPP's proposal applies the existing resource-to-load distribution factor and binding reserve zone conditions for all resources while retaining other conditions for resources in an FCA. ■

Generation Added in the Past Week

YES ENERGY



Early Development
Advanced Development
Under Construction

Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Coal | Hydro

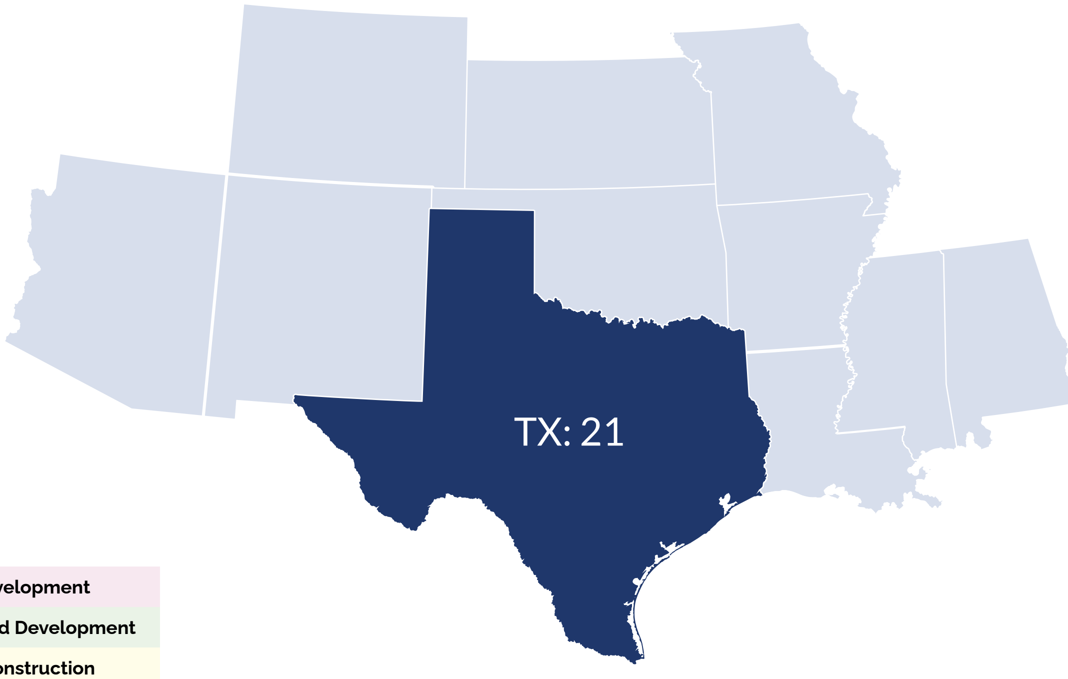
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
Solar	**Windsor Locks**	Engie SA	Engie North America	CT	2	2028
Solar	**USS Man Solar**	United States Solar Corp.		IL	2	2026
Wind	**Bitter Ridge Wind Farm Upgrade**	Brookfield Asset Management	Scout Clean Energy	IN	13	2028
Wind	**Wild Plains Wind Project II**	Nextera Energy	ESI ENERGY	KS	200	2025
Energy Storage	**Cimarron Energy Storage**	Nextera Energy	ESI Energy	KS	166	2026
Wind	**Rice County Energy Center**	Nextera Energy	ESI Energy	KS	300	2026
Energy Storage	**Rice County Energy Center BESS**	Nextera Energy	ESI Energy	KS	300	2028
Solar	**Wades Stream Solar**	Axium Infrastructure Inc.	BlueWave	MA	2	2028
Solar	**Heartwood Solar II**	Ranger Power	Ranger Solar	MI	140	2026
Energy Storage	**Sholes Energy Storage**	Nextera Energy	ESI Energy	NE	160	2026
Solar	**NY USLE Long Lane I**	38 Degrees North		NY	5	2026
Solar	**Club Ford Energy Center (LU-Club Ford 1)**	MN8 Energy		PA	60	2026
Solar	**Upper Macungie CSG 1 Solar**	Dimension Renewable Energy	Dimension Energy	PA	3	2026
Solar	**Tobacco Trail Solar**	Strata Clean Energy		VA	150	2025

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Generation 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
	Lytton Springs BESS	SUSI Partners	SETF	TX	76	2029
	Lytton Springs Solar	SUSI Partners	SETF	TX	75	2029
	Alkali Creek Wind 2	Ownership Undisclosed		TX	250	2030
	Horsepower BESS	Ownership Undisclosed		TX	258	2031
	Main Horn Solar	Ownership Undisclosed		TX	100	2031
	Milam Station Power Secured Gas Generation	Ownership Undisclosed		TX	846	2032
	Two Step Solar	Ownership Undisclosed		TX	405	2033
	Zunkerville Solar	Ownership Undisclosed		TX	201	2030
	Great Prairie Energy Storage II & III	Nextera Energy	ESI Energy	TX	457/208	2031
	McLemore Energy Center	Nextera Energy	ESI Energy	TX	180	2031
	Pecan Ridge BESS	Luminous Energy		TX	151	2029
	Valcrest BESS	Flexen USA		TX	154	2030
	Exergy Energy West Texas Natural Gas Reciprocating Power I	Exergy Development Group		TX	400	2031
	Dilley Solar	AETS Development Holdings	AETS Development Holdings LLC	TX	201	2030
	Prairie Ridge (Gas - CC)	Tenaska		TX	1,660	2035
	Kickstart Energy Storage V & VI	Ownership Undisclosed		TX	999/1026	2034
	Miller Bend Energy BESS	Ownership Undisclosed		TX	548	2034
	Miller Bend Energy Solar	Ownership Undisclosed		TX	532	2034
	Oak Belt Solar	Ownership Undisclosed		TX	181	2032
	Oak Belt Storage	Ownership Undisclosed		TX	207	2032
	Velveteen Solar I & II	Ownership Undisclosed		TX	509/306	2032
	Alila BESS II	BP PLC	BP Alternative Energy North America, Inc.	TX	206	2032

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

Microsoft Proposes $13.3B Wisconsin Expansion

Microsoft is planning a $13.3 billion expansion of its Mount Pleasant, Wisc., operations, proposing to build 15 new data centers and other facilities across more than 1,300 acres.

The development includes two separate campuses: a Durand Avenue Site with up to nine data centers and a 96,000-square-foot office and storage building, and an International Drive Site with six data centers and a 74,000-square-foot office and storage building.

The expansion plans were submitted to the Mount Pleasant Plan Commission.

More: *Racine County Eye*

Court Approves Amazon Acquisition of Solar Project

The U.S. Bankruptcy Court for the Southern District of Texas approved the sale of the Sunstone solar-plus-storage project to Amazon Energy for $83 million.

The 1.2-GW solar and 1.2-GW battery storage asset in Oregon was previously held by Pine Gate Renewables. Pine Gate filed for Chapter 11 bankruptcy protection in 2025.

More: *pv magazine*

Laser Company Invests $1.3B to Enrich Uranium

Laser Isotope Separation Technologies announced it plans to build a $1.3 billion uranium enrichment complex at the Heritage Center Industrial Park in Tennessee.

LIS has the only laser uranium enrichment technology created and patented in the U.S.

The facility should create more than 200 jobs over a seven-year period. In return for its investment, Oak Ridge will halve LIS' property taxes over 15 years.

More: *Knoxville News Sentinel*

Federal Briefs

Judge: Trump Admin Unlawfully Suspended NEVI

Judge Tana Lin, of the U.S. District Court for Western Washington, ruled that the Trump administration unlawfully suspended funding awarded to support the expansion of EV charger infrastructure.

Lin ruled in favor of 20 states and D.C., which had filed their lawsuit after the Department of Transportation in February suspended the National Electric Vehicle Infrastructure program enacted by Congress in 2021 under President Joe Biden.

The Trump administration argued it was a temporary pause, which it later ended after the judge earlier issued a preliminary injunction and the agency issued new guidance.

More: *Reuters*

Study: 50% of CO2 Emissions Come from 32 Companies

A report from think tank InfluenceMap claims 32 fossil fuel companies were responsible for half the global carbon dioxide emissions in 2024.

State-owned fossil fuel producers made up 17 of the top 20 emitters in the Carbon Majors report. All 17 are controlled by countries that opposed a proposed fossil fuel phaseout at the U.N.'s COP30 climate summit in December.

Saudi Aramco was the biggest state-controlled polluter, as it was responsible for 1.7 billion tons of CO_2 from exported oil. ExxonMobil was the largest investor-owned polluter at 610 million tons.

More: *The Guardian*

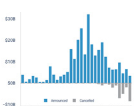
Europe Reinforces Wind Commitment with 100-GW Pledge

The U.K., Germany, Denmark and other European countries signed a clean energy pact at a summit in Hamburg, pledging to deliver 100 GW of offshore wind power through large-scale joint projects, the British government said.

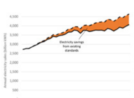
North Sea countries agreed in 2023 to a broader goal of 300 GW of offshore wind capacity by 2050. That followed Russia's invasion of Ukraine, which sharpened fears about Europe's dependency on Russian gas. The new deal will be signed at the North Sea Summit by Britain, Belgium, Denmark, France, Germany, Iceland, Ireland, Luxembourg, the Netherlands and Norway.

More: *Reuters*

National/Federal news from our other channels



Cleantech Manufacturing Investments Drop, Cancellations Rise — NetZero Insider



Study Finds Appliance Standards Saved Households $780B over a Decade — NetZero Insider

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

State Briefs

CALIFORNIA

State Surpasses 2.5 Million ZEV Sales

The state has surpassed 2.5 million cumulative zero-emission vehicle sales in 2025, according to the Energy Commission.

In the fourth quarter of 2025, Californians bought 79,066 new ZEVs, accounting for 18.9% of all new vehicle sales. Meanwhile, cumulative new ZEV sales have grown by more than 300% since 2019.

More: *EV Infrastructure News*

CONNECTICUT

Green Bank Sues Bankrupt PosiGen for $22M

The Connecticut Green Bank filed a lawsuit seeking repayment of $22.2 million in outstanding loans made to PosiGen, a solar panel leasing company that filed for bankruptcy in November.

The Green Bank, which receives roughly $23 million per year from ratepayers through a charge to invest in green technology, partnered with PosiGen between 2015 and 2021 to lease solar panels to low- and moderate-income households. Overall, the bank loaned PosiGen a total of $56.7 million "through a variety of loan facilities," but it said it did not lend any ratepayer funds.

More: *Inside Investigator*

IOWA

House Passes Bill Banning Eminent Domain for Carbon Pipelines

The House of Representatives voted 64-28 to pass a bill that ban the use of eminent domain for carbon capture pipelines.

The bill now goes to the Senate for consideration.

More: *Iowa Public Radio*

MARYLAND

Gov. Moore Proposes Record Funds for Renewables

Gov. Wes Moore proposed a record $306 million for renewable and clean energy programs in the fiscal year 2027 budget.

Much of that money would be drawn from the Strategic Energy Investment Fund, which is managed by the state Energy Administration and is funded by utility payments and proceeds from the Regional Greenhouse Gas Initiative. Climate funding from SEIF in the fiscal year 2027 budget stood at about $328 million.

Moore's total budget was $70.8 billion and accounts for an estimated $1.5 billion cash shortfall.

More: *Inside Climate News*

MASSACHUSETTS

Gov. Healey to Spend $180M to Help Reduce Utility Bills

Gov. **Maura Healey** plans to spend $180 million as part of a plan to temporarily reduce electricity gas bills by 25% and 10%, respectively, for residential customers for the months of February and March, the administration announced.

A spokesperson for Energy and Environmental Affairs Secretary Rebecca Tepper said the $180 million the administration plans to tap will cover an estimated 15% reduction in electricity bills. Utilities will then delay collecting an additional 10% of electric bills in February and March, with plans to recover those payments April through December. Companies will also plan to defer an estimated 10% of gas bill payments during February and March.

More: *WBUR*

MINNESOTA

PUC Rules Burning Trash, Wood 'Carbon-free'

The Public Utilities Commission last week confirmed a law that says burning trash and wood to generate electricity will now be considered a carbon-free source.

The PUC ruled that facilities that burn municipal waste or biomass to generate electricity can still be considered carbon-free, even if they emit large amounts of carbon dioxide or other greenhouse emissions. They can do so if they pass a life-cycle analysis that proves burning trash or biomass generates fewer greenhouse gases than what would most likely occur if the wood or waste were disposed in another manner.

Only about 2% of electricity generated in the state comes from biomass and trash incineration.

More: *MPR News*

NEVADA

NV Energy Offers to Make Overcharged Customers Whole

NV Energy, which balked weeks ago at fully reimbursing overcharged customers, is reversing course and proposing to pay $63 million to more than 100,000 residential customers it has overcharged since 2002, the company announced.

The utility, which owed customers a total of $65.4 million, initially offered to reimburse a portion of affected customers just $2.5 million, claiming regulations limited their obligation to repay customers for just six months of overcharges. The offer "ensures that compensation is provided expeditiously" following Public Utilities Commission approval, NV Energy said.

More: *Nevada Current*

TEXAS

EPE Requests Gas Plant for Data Center

El Paso Electric is seeking Public Utility Commission approval for a 366-MW natural gas power plant that will fuel a $1.5 billion, 1-GW Meta data center.

The plant will be exclusively connected to the data center for the first five years, according to filings. Then it would be connected to the broader El Paso Electric grid. Meta would be responsible for all the costs during the first five years.

The plant will require approvals from both the PUC and the Commission on Environmental Quality. If approved, it is expected to be operational by 2027.

More: *Inside Climate News*