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Northwest Lawmakers Explore Building Transmission Without BPA's Help

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Oregon and Washington lawmakers are exploring ways to build new transmission independent of the Bonneville Power Administration as electric sector stakeholders in the Pacific Northwest worry about the agency's struggle to build transmission fast enough to keep up with aggressive clean energy laws and increased load.

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Policy Roundup: DOJ Sues California on EVs; DOE Offers $1.9B for ATTs (p.5)

The Trump administration has sued California over its electric vehicle law, claiming it amounts to an illegal, state-specific mileage requirement for carmakers.

ERCOT

AdminMonitor

Texas PUC Proposes Large Load Interconnection Standards (p.25)

A new standard would set consequences should a large load customer withdraw all or a portion of requested peak demand and would establish a refund of financial security when a large load energizes.

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EDAM Governance Questioned During NV Energy Hearing (p.18)

If the Nevada PUC doesn't approve NV Energy's request to join EDAM, the day-ahead market could lose a large and central piece of its footprint.

In this week's issue

A Cautionary Tale on Forecasts

By Kenneth W. Costello

Forecasting is like driving a car blindfolded while following directions given by someone who is looking out of the back window. — Anonymous


Ken Costello

Utility regulators beware: Not all forecasts are objective. Some are normative or biased, while others are based on science. When making important decisions, regulators must frequently choose between competing forecasts submitted by parties with varying agendas.

With potentially billions of dollars at stake, regulators need to reconcile the "forecast" discrepancies. Just as important but often overlooked, regulators also need to know the range of plausible forecasts and the risks associated with accepting one forecast over others. The risks triggered by uncertainty can play an important role in regulatory decisions.

Much of the push for a particular decision, whether for long-term planning purposes, merger proposals, determining future utility rates or other matters, comes from interest groups.

Regulators should receive their forecasts, which are critical for decision-making, with a grain of salt. They should ask if the forecasts are self-serving or are they legitimate and reflect objective analysis? Gaming by different stakeholders can present regulators with biased forecasts, which would require special regulatory-staff expertise to uncover.

Hedging Under Uncertainty

Often ignored, regulators should hedge their decisions to account for the inherent uncertainty associated with forecasting the future. A *rational decision-maker* would tend to respond to future unknowns by exercising caution in committing to a major action today.

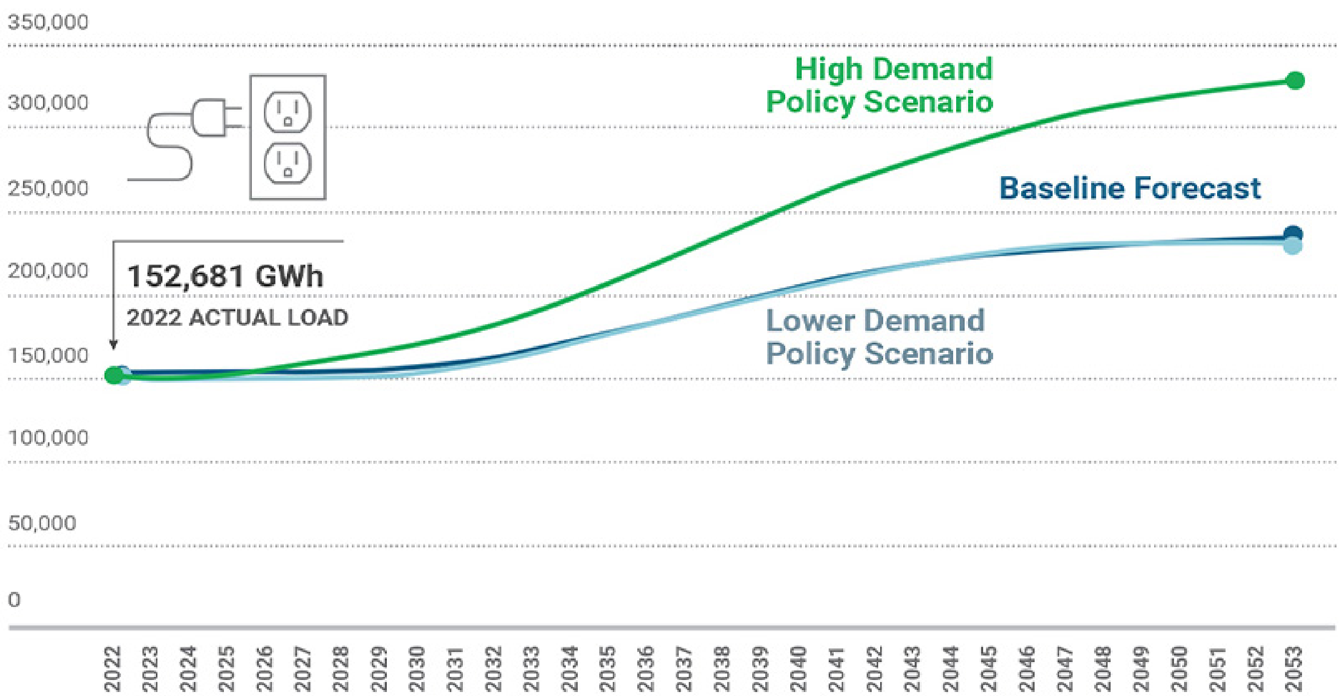
Regulators therefore should require utilities and other parties to submit a reasonable range of forecasts to justify their positions. Basing a large investment or other major decision solely on the "best guess" forecast, or the future deemed most likely to occur, can result in substantially higher costs relative to the best action determined *ex post facto* with actual outcomes. In other words, an avoidable risky decision is more likely when based only on information provided by a "best guess" forecast without considering other possible futures and their implications for the right decision.

Why This Matters

The building of a generating facility based on demand growth of 5%, for example, could cost the utility an additional $100 million a year compared with building the facility when the actual demand growth turns out to be 3%, warns energy consultant Kenneth W. Costello.

A range of forecasts or scenarios can help regulators quantify and evaluate the risks associated with individual decisions, related to electric-generation planning, energy efficiency initiatives or other actions, then judge whether the risks are intolerable. Uncertainty requires regulators and utilities to ask if the possible maximum losses from a particular decision are large enough to disqualify that decision from further consideration.

I use the term "forecast" to encompass both 1.) the future outcome that is most likely to occur (i.e., the "best guess" or single-point forecast) and 2.) a future



Load forecasts that are off by even a couple of percentage points can have a dramatic effect. | *NYISO* outcome that is less likely to occur based on an alternative set of assumptions like economic conditions, the price of electricity, the price of substitutes for utility electricity, and the economics of renewable energy.

Some analysts refer to "*best guess*" forecasts as reference forecasts when they reflect the future with the highest probability of occurrence. The forecast is based on a set of events the forecaster expects will occur or considers more likely to occur than other events. If one has to choose a single forecast with a bet of $100 on the line, what would it be? It would presumably be the "best guess" forecast since the payoff would go to the person whose forecast lies closest to the actual outcome.

The regulator makes choices by using forecasts provided by utility stakeholders. First, it could approve the utility action based on the single-point price forecast; for example, the "best guess" demand growth of electricity 4% per annum, so the decision is contingent only on this forecast. This is a valid decision, however, only when 1.) the regulator places a high degree of confidence in single-point forecasts, and 2.) the consequences of incorrectly forecasting demand within a large range are minimal. For example, the preferred decision does not depend on whether demand growth is 2% or 4%. Otherwise, the regulator lacks access to valuable information to decide.

This situation is analogous to a person choosing a financial asset with the highest expected return, say, stock in a high-tech company, without considering its risk relative to other assets.

Most people would decide not to allocate all their investments to this high-return, high-risk asset. They would tend to diversify their investment portfolios to balance the tradeoff between return and risk. For financial assets, diversification implies an objective other than maximizing expected return or minimizing risk. Diversification reflects managing risk at a cost acceptable to the decision-maker given the degree and nature of their risk adversity.

Modern portfolio theory considers the inherent risk in various financial and physical assets and develops methods for aggregating investments to maximize the tradeoff between risk and return. In a different context, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies, even if the other technologies have lower expected levelized costs.

Using Different Forecasts

In our above example, as an alternative, the regulator could approve the utility action based on a range of demand-growth forecasts. It could, for example, review several forecasts from credible sources to select high, medium and low forecasts that represent reasonable demand-growth possibilities.

The evidence might show that demand-growth forecasts within a certain range result in the same preferred decision (e.g., expand generating capacity by a certain level by the year 2035). *This sensitivity analysis* makes the regulator more confident that the action taken will carry little risk unless it assigns a non-trivial probability to demand growth beyond the selected range. (The risk would be the opportunity cost of making a particular decision when another decision would have produced a better outcome after the fact.) Analysts consider such actions to be robust under a wide range of conditions. Robustness means that regulators would require less precision from a "best guess" forecast.

The regulator could approve the utility action after considering the cost of making the wrong decision based on erroneous demand forecasts (i.e., the loss function). The building of a generating facility based on demand growth of 5%, for example, could cost the utility an additional $100 million a year, compared with building the facility when the actual demand growth turns out to be 3%.

The regulator might want the utility to "hedge" its plan to moderate the cost (i.e., loss) from mis-forecasting demand growth. One idea is for the regulator to instruct the utility to take a wait-and-see approach as it accumulates more information to improve its forecasting accuracy before committing to a decision. To the extent that waiting reduces demand-growth uncertainty, the utility may reap an "option value" from an investment delay stemming from this uncertainty.

Loss Function

Rational risk-averse decision makers, implicitly if not explicitly, apply what is called *a "loss function."* This function calculates the cost of a decision conditioned on a single forecast or range of forecasts that turn out to be wrong. Assume the decision to build a new gas-fired generating plant is contingent on the natural gas price being in the range of $3 to $5.

If the actual price is $7, the utility's revenue requirements would be $500 million lower if it chose to build a solar facility instead. The $500 million represents a loss from relying on the wrong forecasts, which is inevitable when dealing with something as dynamic and unpredictable as demand growth, natural gas prices and other factors affecting the optimal decision.

The above example has a parallel to the current *climate-change debate*. Studies have shown that catastrophic consequences can follow if we do not take actions today to reduce greenhouse gases, but these consequences are highly uncertain, so much so that scientists cannot assign probabilities to their likelihood.

We may, therefore, spend money today to avoid an outcome that may never occur. The question is: What should we do today? The same question applies when an event is unlikely to occur but will cause a catastrophic outcome if it does. A society, group or individual that is risk-averse would tend to spend something today, for example buying insurance, to mitigate possible financial consequences in the future.

Distorted Incentives?

Although less guilty than in the past, utilities, in my observation, place excessive reliance on "best guess" forecasts to justify major decisions and fail to include a loss function in their forecasting exercise. One question still lingers: Does this problem reflect flawed decision-making, or do utilities and regulators deliberately produce and approve forecasts with overblown sureness and absent information on the negative consequences of erroneous forecasts?

The latter reason could be to buttress a particular, politically palatable action or, in some other way, advantageous to a utility or the regulator. One has to wonder. ■

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

Policy Roundup: DOJ Sues California on EVs; DOE Offers $1.9B for ATTs

By James Downing

The Trump administration has sued California over its electric vehicle law, claiming it amounts to an illegal, state-specific mileage requirement for carmakers.

The U.S. Department of Justice filed the *lawsuit* on behalf of the National Highway Traffic Safety Administration (NHTSA), which under the Energy Policy and Conservation Act is supposed to establish "uniform, nationwide vehicle fuel economy standards."

"Oppressive, expensive electric vehicle mandates drive up costs for American consumers and violate federal law," Attorney General Pamela Bondi said in a statement March 12. "California is using unlawful policies from the last administration to create exorbitant costs for our citizens."

The lawsuit names the California Air Resources Board (CARB) as a respondent, arguing that its carbon and zero-emissions vehicle mandates are related to fuel economy standards because they effectively increase fuel economy, which is determined by how much carbon is emitted from a vehicle's tailpipe.

"CARB's standards and mandates also undermine and conflict with NHTSA's congressionally assigned role in establishing nationwide, uniform vehicle fuel economy standards," the lawsuit said. "CARB's CO_2 standards and ZEV mandates create a patchwork of inconsistent regulation for vehicle and engine manufacturers in an area where Congress imposed a uniform, national approach."

The Environmental Defense Fund called the lawsuit "reckless," saying the ZEV standard protects Californians from health-harming and climate-destabilizing pollution.

"California's standards are firmly anchored in our nation's clean air laws," EDF Associate Vice President Peter Zalzal said in a statement. "For more than half a century, and across both Republican and Democratic presidential administrations, California has adopted standards that cut pollution and result in enormous health benefits for people across the state."

| Shutterstock

DOE Announces Funding for ATTs

The U.S. Department of Energy announced a $1.9 billion funding opportunity to accelerate upgrades to the nation's power grid, saying the investments will meet rising electricity demand and resource needs while lowering costs for consumers.

DOE said the "Speed to Power through Accelerated Reconductoring and Other Key Advanced Transmission Technology Upgrades" opportunity builds on the Grid Resilience and Innovation Partnerships program, which offered up to $10.5 billion in funding over five years to states, tribes, utilities and others to strengthen grid resilience and innovation. (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

"Thanks to President Trump, we are doing the important work of modernizing our grid so electricity costs will be lowered for American families and businesses," U.S. Secretary of Energy Chris Wright said in a statement March 12.

DOE wants concept papers by April 2, and full applications are due May 20. The agency expects to make selections in August.

The funding was welcomed by the WATT Coalition, with its Executive Director Julia Selker saying ATTs can help address affordability.

"American utilities have demonstrated that ATTs could unlock gigawatts of grid capacity and save billions in electricity costs if scaled across the country," Selker said. "This funding will help utilities scale up their ambitions and timelines for transmission grid modernization." ■

EIA Expects No Impact on Domestic Natural Gas Prices from Iran Conflict

By James Downing

The war in Iran is not expected to lead to higher domestic natural gas prices in part because higher oil prices tied to the closure of the Strait of Hormuz mean more oil production and related gas supply from the Permian Basin, the U.S. Energy Information Administration said.

In its monthly *Short-Term Energy Outlook*, released March 10, EIA explained how Iran's closure of the strait in response to a bombing campaign by the U.S. and Israel raised global oil and LNG prices.

The Brent crude oil spot price was up sharply since the start of military action in the Middle East, settling at $94/barrel March 9, a 50% boost since the start of the year and the highest since September 2023.

"We make the assumption in our modeling that the effective closure of the Strait of Hormuz will cause oil production in the Middle East to fall further in the coming weeks," EIA said. "We assume this shut-in production will gradually ease as transit through the strait resumes."

Nearly 20% of global oil trade flows through the strait, which is between Iran and the Arabian Peninsula, along with about 20% of global LNG, mainly from Qatar to East Asia. Global LNG prices have shot up, but U.S. export capability was already operating near capacity before the bombing began.

In the short term, EIA predicts national average natural gas prices of $3.80/MMBtu, 13% lower than last month's figure, as more of the fuel was left in storage than it had expected.

Why This Matters

Natural gas prices are often the marginal fuel in ISO/RTO markets, so their relative stability means they will not pressure wholesale power prices.

Calcasieu Pass LNG Facility | *Venture Global LNG*

"The Henry Hub spot price averages nearly $3.90/MMBtu in 2027, 12% lower than our forecast last month," EIA said. "Lower prices in 2027 mostly reflect more associated natural gas production as a result of the recent increase in oil prices and the related increase in production later in the forecast."

Higher crude production results in more associated natural gas production, and EIA expects the latter to rise 2% from 2025 to 121 Bcfd this year and an additional 3% in 2027 to 124 Bcfd. The 2027 figure is 2 Bcfd higher than EIA forecast a month ago.

"Elevated oil prices will drive more oil-directed drilling in the Permian, which will contribute to greater volumes of associated natural gas production," EIA said.

National average residential electricity prices are expected to rise slightly this year and next, going from 16.5 cents/kWh in 2025 to 17.3 cents/kWh in 2026 and 18 cents/kWh in 2027.

"We expect U.S. electricity generation will grow by 1.2% in 2026 and by 3.1% in 2027, which follows recent upward trends in generation to meet growing electricity demand," EIA said. "Between 2010 and 2019, electricity generation was essentially unchanged, as electricity demand from a growing population was offset by the use of more efficient appliances and heating and cooling equipment. But since 2021, U.S. generation has been growing [at] an average of about 2% per year."

The biggest growth is in ERCOT, where EIA said generation is expected to grow by 7.3%, leading to increases across all technology types. The rest of the country is expected to see less generation from natural gas plants, as the delivered price of the fuel for generators is up 8%.

Higher gas prices tend to favor generation from coal plants as a substitute, but with operators currently planning to retire 4% of coal capacity and the growth of renewables, EIA forecasts coal generation will drop 7% this year, mostly in the Midwest and Southeast. Plans to retire coal plants are subject to change, the agency *noted*. ■

NRC Finds Minor Violations, Elevates Oversight of 5 Reactors

Low Safety Significance Assigned to Findings of Annual Site Assessments

By John Cropley

The *Nuclear Regulatory Commission* reports that 90 of the nation's 95 operational commercial nuclear reactors met the highest category of performance in the 2025 oversight process.

The other five fell into the second performance category — indicating findings of low safety significance — and will face an elevated level of regulatory oversight including additional inspections and follow-up on corrective actions.

No reactors fell to the third or fourth performance categories, which trigger additional NRC oversight, or the fifth, which prompts a shutdown while problems are addressed.

The March 13 announcement of *annual assessments* for nuclear plants is a reminder of the level of regulation the NRC applies as it faces pressure by the Trump administration to streamline and speed up its regulatory process to facilitate a dramatic expansion of the U.S. nuclear power sector.

This *has prompted concerns* about the NRC being able to maintain its independence and its core mission of upholding the safety of aging infrastructure that harnesses potentially dangerous technology to *produce 18%* of U.S. electricity — *784,781 GWh* in 2025.

The five reactors flagged for additional attention are Hope Creek in New Jersey, South Texas Project Unit 2, V.C. Summer in South Carolina and Watts Bar 1 and 2 in Tennessee.

PSEG's *Hope Creek* got a notice of violation for "Inadequate Identification and Correction of Water Intrusion into Emergency Diesel Generator Lube Oil System" despite multiple indications of a degraded condition. This resulted in loss of probabilistic risk assessment function greater than the allowed outage time.

STP's *South Texas Project Unit 2* was flagged for "Failure to Establish Adequate Preventative Maintenance Instructions Leading to Multiple Component Failures" that

Why This Matters

The filings show the level of oversight applied by the Nuclear Regulatory Commission, which is making significant streamlining efforts on orders of President Trump.

resulted in "a partial loss of offsite power, an unplanned reactor trip, and subsequent loss of a safety-related motor control center during recovery activities."

TVA's *Watts Bar 1* and *Watts Bar 2* were dinged for "Failure to Maintain Public Address System" as procedure dictated. From February 2019 to June 2025, TVA failed to characterize as "loss of function" the continuous and progressive failure of multiple speakers important to emergency response and failed to take corrective action or implement compensatory measures.

All of these were determined to be of low safety significance — a white violation, *the second-lowest color* on a scale that runs from green to white to yellow to red. Other findings at each of the four reactors were classified green — non-violations or non-cited violations.

The NRC website lists numerous green but no white findings for the fifth reactor, Dominion's *V.C. Summer*. The NRC's March 11 letter to Dominion said V.C. Summer was being placed on the supplemental oversight list with the other four reactors because of a "white" finding in the third quarter of 2025.

This might be the "Inadequate Maintenance Strategy Resulting in Turbine-Driven Emergency Feedwater Pump Inoperability," but that is listed as an "apparent violation" on the NRC website, with no color code.

The "green" findings at the five reactors span a wide range of failures or missteps. They include:

- Failure to Control a Locked High Radiation Area.
- Incorrect Rod Control Setup Resulted in Unanticipated Control Rod Withdrawal.
- Failure to Maintain Quality of Lubricants.
- Degradation of Main Generator Current Transformer 152C Causes Automatic Turbine and Reactor Trip.
- Change to Emergency Diesel Generator Operating Procedure Without Obtaining a License Amendment.
- Failure to Demonstrate Effective Control of a Maintenance Rule Scoped System.
- Failure to Translate High Head Safety Injection Pump Maximum Shutoff Head into Motor Operated Valve Thrust Calculations.
- Failure to Remove Rubber Shipping Grommet During Emergency Feedwater Pump Governor Installation.

The NRC deemed all the "green" findings notable enough to report, even if they were not worthy of citations or increased oversight.

Individually and in the aggregate, they are deemed not a threat to safety. But as a whole, they hint at the vast range of potential human errors in these huge, complex systems and point to the degree of scrutiny the NRC applies in seeking and documenting those failures.

President Donald Trump took aim at the NRC's layers of regulation in one of *four May 2025 executive orders* intended to streamline nuclear power development. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

The order that focuses on the NRC (*EO 14300*) seems to be aimed at expediting the approval of new reactors and technology, a stated priority for Trump. But it is blunt in criticizing the entire approach of the nuclear watchdog, as when the president cited "a myopic policy of minimizing even trivial risks."

He wrote: "Instead of efficiently promoting safe, abundant nuclear energy, the NRC has instead tried to insulate Americans from the most remote risks without appropriate regard for the severe domestic and geopolitical costs of such risk aversion."

And: "Beginning today, my administration will reform the NRC, including its structure, personnel, regulations and basic operations."

Where this directive translates to action and what it means for routine processes such as the annual assessments for 95 nuclear reactors remain to be seen, but clarity may be coming.

The baseline inspections now total 2,012 hours per year, according to a Feb. 6 NRC *memo recommending revisions*. *Attachments to the memo* include a *specific 38% suggested reduction* in hours, *organizational changes* and potential changes to *more-than-minor findings*.

These last changes could include reducing the number of publicly reported green findings in a way that would not reduce their effectiveness but would reduce the chances of the public getting the wrong impression about the safety implications of those findings, or about the performance of the reactor's license holder.

The NRC's website indicates *three of 28 planned revisions* of rules in response to EO 14300 had been completed as of March 6.

And in January, the Department of Energy *eliminated or rewrote* numerous safety rules including ALARA, a longstanding core principle that dictated nuclear operators must keep radiation exposure As Low As Reasonably Achievable.

As this wholesale revision moves forward, cutting-edge technology and Cold War-era infrastructure are mingling in NRC's purview: Dozens of advanced reactor designs are in various stages of completion while nuclear plants that went on the drawing boards in the 1960s and 1970s continue to operate with the equipment and technology of that era.

Constellation's Limerick Clean Energy Center made news in January with the announcement the NRC had approved the nation's first-ever wholesale replacement of a nuclear plant's analog safety systems with a single digital system. (See *NRC Approves 1st Digital Conversion of Nuclear Plant Safety Controls*.)

TVA's Watts Bar nuclear plant is among those the Nuclear Regulatory Commission has designated for enhanced oversight. | *Shutterstock*

This is all the more remarkable when considering that even at 40 years old, Limerick is among the newer plants operating in the U.S. — commercial nuclear power construction all but ceased in the early 1990s.

Operators of some the oldest existing facilities are considering relicensing requests that could extend their operating lifespans to 80 years.

So how did the oldest components of the aging fleet fare in the NRC's annual assessment?

Constellation's Nine Mile Point Unit 1 entered commercial service Dec. 1, 1969, and its R.A. Ginna on June 1, 1970. Both *recorded capacity factors* above 94% in 2022-2024, compared with a national median of 91%. And neither got a writeup from the NRC in 2025.

Nine Mile Point Unit 1 got a handful of "green" findings, none of which were cited as violations. Ginna got just one "green" finding — a non-cited violation for failing to rectify a grease packing condition in a valve actuator the vendor had warned about.

On the other end of the scale, Southern Nuclear's Vogtle 3 and Vogtle 4 are the newest reactors (and the only "new" ones) in the U.S. fleet, entering commercial operation on July 31, 2023, and April 29, 2024, respectively.

Vogtle 3 got two non-cited "greens," but it was the same finding reported under two categories.

Vogtle 4 got three different "green" findings a combined eight times under three categories, none resulting in citations.

One of them stands out as a strikingly low-tech flub in such a high-tech setting: propping open fire doors *without maintaining a fire watch*.

The number of reactors placed on expanded supervision in 2025 is slightly less than the annual average in the 2020s. Nine were flagged in 2024, six in 2023, six in 2022, two in 2021 and four in 2020. Of those, one was placed in the third performance category and the rest in the second performance category. ■

Renewable Portfolio Standards Not Boosting Electric Rates, MIT Study Finds

But Authors Say Rooftop Solar More Likely to Raise Costs than Utility-scale Wind or Solar

By John Cropley

A new MIT study posits that while retail electric rates are higher in states that have renewable portfolio standards, the standards are not to blame. Instead, utility-scale wind and solar generation show a weak correlation with lower prices, the authors say.

More likely drivers of rate increases include cost-recovery mechanisms for rooftop solar embedded in certain tariffs, grid-hardening necessitated by climate change and the proliferation of data centers.

The *MIT Sloan School of Management* announced "*Renewables and Electricity Affordability: Untangling Correlation from Causation*" on March 9.

The correlation between renewable energy policies and electricity prices is relatively straightforward, but correlation famously does not imply causation, and as the title suggests, much of the study is devoted to separating and explaining the factors and causes at play.

Solar panels dot rooftops in a northern California neighborhood. | *Shutterstock*

Professor *Christopher Knittel*, MIT Sloan's associate dean for climate and sustainability, and *Fischer Argosino*, a graduate researcher at the MIT Center for Energy and Environmental Policy Research, analyzed U.S. electricity and utility spending data from 1998 to 2023, including residential prices, power generation mixes, utility spending and state RPS.

They said the opposite rate impacts they found for utility-scale and distributed renewables are due partly to the fundamental differences in their design.

"Energy generated by large-scale solar plants, for example, comes with lower transmission, distribution and maintenance costs for utilities, and these efficiencies can be passed on to the consumer," Knittel said in the news release.

But rooftop solar creates a two-way system out of distribution networks that were designed for a one-way flow from central generation plants to consumers, the authors said. They found this bi-directional flow was strongly correlated with higher operations and maintenance costs, as utilities managed the complex harmonization of thousands of decentralized generators across an aging grid.

Why This Matters

The study attempts to clarify the cost structure of renewable energy at a time of financial turmoil for the renewables sector.

"Our antiquated distribution networks are struggling to manage these flows," Argosino said. "When we defer essential grid upgrades while simultaneously incentivizing rooftop exports, we create an operational strain that inevitably shows up as higher costs on everyone's utility bills."

But not uniformly higher. State financial incentives for rooftop solar can shift some of the costs of maintaining the grid onto ratepayers who do not have solar panels, even though solar owners derive full benefit from the grid to power their homes and export their solar panels' output.

This exacerbates existing inequities, the authors said — those who put solar panels on the roofs of their homes are likely to be wealthier than those who do not.

Knittel and Argosino say decarbonization need not be at odds with electric rate affordability, if policies can be updated to match the changes in technology.

They suggest prioritizing utility-scale wind and solar to maximize economy of scale, modernizing distribution networks and adjusting fee structures so that all who benefit from grid infrastructure contribute to the cost of its maintenance.

The research is built on data from the U.S. Energy Information Administration, FERC and the Lawrence Berkeley National Laboratory. The years studied span a period before, during and after the widespread adoption of state RPS. ■

SEIA, WoodMac Chart Whiplash in U.S. Solar Industry

Sector Rushes to Qualify for Federal Tax Credits

By John Cropley

Why This Matters

The data show the U.S. solar sector going strong amid federal policy changes, but how how strong and for how long remains to be determined.

Nearly 40% fewer U.S. solar power projects reached completion in the fourth quarter than in the third quarter as developers pivoted to start new projects in time to qualify for tax credits.

But while the 43.2 GW of solar capacity installed in 2025 was 14% less than in 2024, it nevertheless made up 54% of all new capacity added to the U.S. grid in 2025, the Solar Energy Industries Association (SEIA) and Wood Mackenzie *said in a new report* March 10.

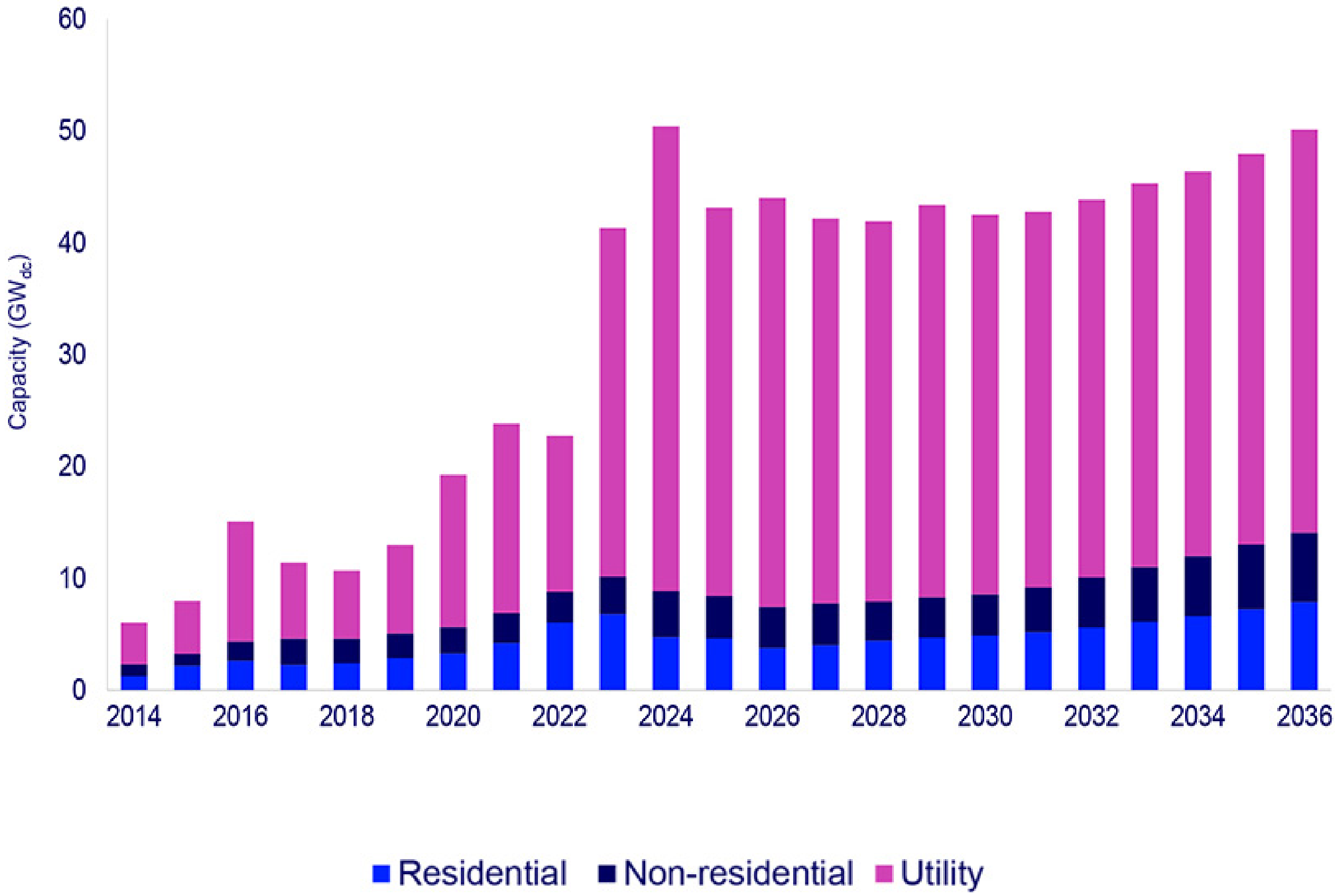
2025 was the fifth straight year solar was the top source of new U.S. power generation capacity.

Looking ahead, the analysis predicts nearly 500 GW of additional photovoltaic capacity will be installed nationwide through 2036, even with the headwinds created by a president hostile to renewable energy. The costs of alternatives are high enough that solar remains a value proposition even without the lucrative investment and production tax credits that are being sunsetted sooner than originally planned.

"It's clear that solar will continue to be the dominant source of new power capacity in the United States, even as gas generation continues to grow," said Michelle Davis, head of solar at Wood Mackenzie and lead author of the report. "Strong demand growth combined with escalating costs of new gas plants will allow solar to remain competitive, even without tax credits."

The "U.S. Solar Market Insight 2025 Year in Review" acknowledges the many uncertainties facing solar power. The baseline prediction of 490 GW more solar capacity by 2036 could be 11% higher or lower due to a series of factors, but the projected variation for utility-scale solar (6-7%) is much less than for distributed solar (23-28%).

Distributed solar is more sensitive to changes in retail rates and cost-impacting policies such as tariffs and import guidance, the authors state, while utility-scale projects are more likely to be affected by interconnection bottlenecks,



Historic and projected growth in U.S. solar power generation installation | *Wood Mackenzie* supply chain constraints and power demand growth.

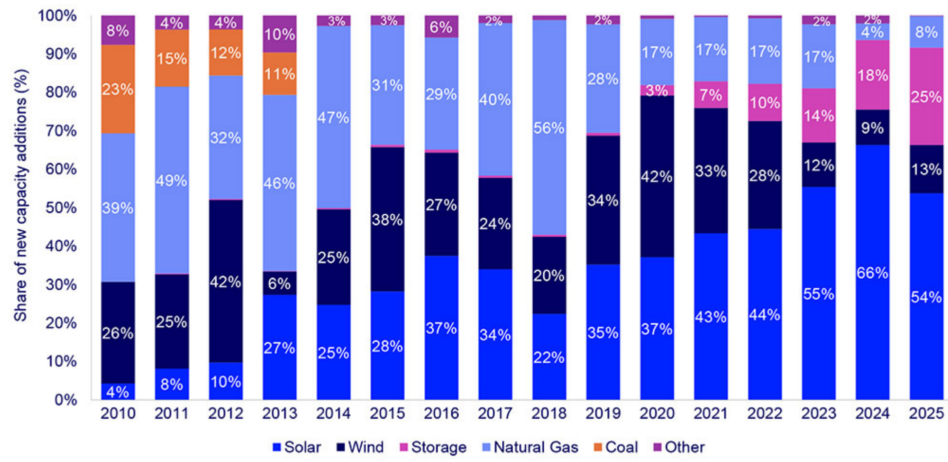
Another unknown factor is President Donald Trump.

Trump's signature on the One Big Beautiful Bill Act in July 2025 moved forward the expiration of tax credits in the Inflation Reduction Act.

Projects now must start construction before July 4, 2026, or be placed into service by Dec. 31, 2027, to qualify for full tax credits. This led to significantly fewer completed projects in 2025 than expected — the value of completing them was outweighed by the imperative of beginning work on the next projects in the pipeline in order to safe harbor their tax credits.

While the president relentlessly boosts fossil fuels over renewables, he does not show the same level of hostility to solar panels as to wind turbines. There even have been a few hints in early 2026 of *solar opposition softening* among *some MAGA influencers*.

Whatever the motive for this turnaround, solar has some effective selling points in 2026: It is faster and less expensive to deploy than gas or nuclear; U.S. solar component manufacturing has expanded greatly; and battery energy storage



Solar power's growth as a U.S. power generation technology is shown. | *Wood Mackenzie*

systems to smooth out solar's intermittent performance are proliferating in number while decreasing in price.

SEIA interim President Darren Van't Hof indicated that while the federal uncertainty has not gone unnoticed, it is not insurmountable: "Solar and storage continue to dominate new capacity additions to the grid despite policy headwinds. American households and businesses of all sizes are demanding solar + storage because they deliver fast, affordable power to help meet rapidly rising demand," he said.

"Washington must deliver policy certainty for the market to work and to keep pace with growing energy demands. Without this certainty, less solar will get built and Americans will pay the price with higher energy bills."

Even with this churn, all of Wood Mackenzie's U.S. power projections show solar constituting nearly half of all U.S. capacity additions each year through 2060.

The 2025 outlook calls for an average annual addition of 44 GW through 2036, which is an increase over previous projections based on the increase in the near-term utility-scale pipeline and continued growth in energy demand expectations. ■

Utilize the Grid Better to Save $100B+, New Coalition Urges

Google, Tesla, Others will Push for State-level Policy Changes

By John Cropley

A new industry coalition calling itself Utilize has begun a campaign to make electricity less expensive and quicker to connect by unlocking underused grid capacity.

Utilize announced its launch March 10 and said it soon will release a Brattle Group research report showing that better use of existing grid infrastructure could save more than $100 billion over 10 years.

The coalition's charter members are a cross-section of energy providers and users including Carrier, Google, Renew Home, SPAN, Sparkfund, Tesla and Verrus.

Utilize is designed as a nonpartisan campaign focused on influencing state-level regulators, elected officials, utilities and stakeholders.

In its announcement, Utilize emphasized one of the salient themes of the 2026 campaign season: consumer costs. It said the $100 billion in savings would accrue to consumers on their electric bills and allow consumers to connect to the grid more quickly. But it also said better utilization would help states meet the growing power demands created by data centers, manufacturing and electrification without delay or excess cost.

The power grid is built for peak demand, and the excess capacity in non-peak periods has been cited repeatedly as a potential resource to meet new non-peak demand, particularly if more users were more flexible in their peak demand.

Utilize cited an influential 2025 *Duke University study* showing the existing grid could handle 126 GW of new demand with no additional generation if data centers cut their power use as little as 1% in peak periods. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

In the 13 months since the study was released, many other people have reached the same conclusion, and Duke *issued a follow-up report* that drilled down on the benefits. (See *Duke University Study Quantifies Benefits of Data Center Flexibility*.)

Why This Matters

The coalition is the latest voice to call for more complete use of existing grid assets.

The Federal Reserve Bank of St. Louis *recently charted* U.S. grid capacity utilization dropping from just over 100% in July 1999 to just over 68% in August 2025. It averaged 71.27% in January 2026, the most recent month charted.

Now Utilize wants to translate research into action.

"For decades, we've built the grid to meet peak demand, even though large portions of it sit unused for most hours of the year," Executive Director Ian Magruder said.

"It's like building an airplane that only flies with full passengers a few times a year. That excess capacity is hiding in plain sight, and new technologies give us the opportunity to unlock it. Better grid utilization is one of the fastest, most practical levers states can pull to reduce power bills while supporting economic growth."

Utilize said it will support technology-neutral policies that align planning, incentives and regulatory framework to meet the objectives of affordability, reliability and speed.

The goal is to make better grid utilization a core principle of U.S. grid planning.

Utilize cited the 2025 Duke study's finding that the 22 regional power systems examined operated at just 53% of capacity on average.

Utilize also pointed to a 2025 *Stanford University study* showing that even during peaks, most Western U.S. transmission lines were carrying only 18 to 52% of their available capacity, with most clustered around 30% of capacity. But the excess capacity is not consistently accessible due to operational and planning constraints; Utilize said better utilization would allow for more demand to be served and would spread the fixed grid costs across more electricity sales.

The new Utilize coalition adds some prominent names to the push to better utilize the existing grid. Some other recent efforts:

A new partnership announced the same day as Utilize announced itself will design flexible data centers. (See *Emerald AI, InfraPartners Team up to Deploy Flexible Data Centers*.)

Google has funded analyses on flexible data center models and signed some flexibility agreements of its own. (See *Analysis Offers Blueprint for Faster Data Center Interconnection* and *Google Strikes Demand Response Deals with I&M, TVA*.)

A blueprint is being created for placing smaller data centers near stranded power to speed their deployment. Research has shown flexibility would be part of a suite of tools that could limit the financial impacts of data center buildout. Other research has highlighted the value of demand management and energy efficiency.

If "flexibility" seems like a buzzword lately, that's because it is. *RTO Insider* columnist K Kaufmann recently explained the phenomenon. (See *Why 2026 will be the Year of Flexibility*.) ■

The Tesla Megafactory in Lathrop, Calif., is shown. Tesla is part of a new industry consortium seeking to unlock underused grid capacity. | *Tesla*

EPI Report Finds Utility Profits Account for 13% of Bills and Rising

Critics Deride the Report as Merely Inflammatory

By Amanda Durish Cook

Watchdog organization Energy and Policy Institute compiled a report that claims investor-owned utility profit margins are on the rise, with 13-15% of customers' bills bankrolling profits.

EPI's report, "*Paying for Their Profits: How Ratepayers Foot the Bill for Soaring Utility Profits*," said that from 2021 to 2024, utilities kept on average of 13 cents in profit of every dollar customers paid, totaling $195 billion in profits. EPI said electricity bills "far outpaced" inflation and the median wage, affecting customers' ability to pay.

"This is just the latest example of EPI making up alternative definitions that serve the interest of their dark-money benefactors," said Dani Marx, a spokesperson for the Edison Energy Institute, an association that represents investor-owned electric utilities.

Another critic of the report called it "a naked attempt to inflame the public against energy bills that have risen due to the restrictive policies" EPI has "championed for years."

Daniel Tait, EPI's research and communications director, said researchers analyzed publicly available data from about 110 investor-owned utilities across the country from 2021 to 2024. Utilities included electricity-only utilities and those that bill customers jointly for electric and gas service.

Tait said EPI used a "straightforward calculation" of net income divided by total operating revenue.

As part of the report, EPI included a net-profit utility report and calculator *tool*, where ratepayers can look up their utility and type in their bill amounts to figure out what portion of their bills go directly to profits.

"Transparency here is going to be just the first step," Tait said.

Tait said EPI plans to update its calculator tool as utilities report their 2025 financial results. During a March 12 webinar to discuss the report, Tait said data collected so far on 2025 financials show that profit margins are getting larger, closer to 15 cents on the dollar.

Daniel Tait, Energy and Policy Institute | *EPI*

The Bottom Line

With ratepayers struggling to afford bills, the Energy and Policy Institute analyzed 110 utilities, finding that they retained an average 13% of bills as profit.

Tait said EPI found that for an electric bill, an average of $30 goes directly to corporate investors.

"That is money not to keep the lights on, not to build the grid, but just for that profit," Tait said. "And that share is rising as bills have gone up."

EPI said the pattern of rising rates and rising profits "raise important questions about the balance between utility profitability and affordability, especially as customers nationwide face continuously high energy costs and immense financial strain."

Tait said that while politicians and utilities often point to things like fuel costs, infrastructure investments and extreme weather events when explaining rate hikes, they often leave out how much of a customer's bill goes to shareholders.

EPI said that between 2021 and 2024, almost 40 utilities averaged profit margins above 15%, with other utilities trending even higher. Utilities they found with the highest average profit percentages over the four-year period include: MidAmerican Energy (27.22%), Florida Power and Light (23.51%), Nantucket Electric (23.24%), Empire District Electric (22.45%), Florida Public Utilities (20.35%), CalPeco (20.28%), Public Service Electric & Gas (19.44%), Duke Energy Carolinas (19.07%), Alabama Power (18.71%) and AEP Texas (18.63%).

EPI also said that of the 79 utilities that released 2025 financial information at the time it was finalizing its report, the highest profit margins were at Florida Power and Light (27.44%), MidAmerican Energy (27.16%), SoCal Edison (26.11%), Georgia

Power (22.57%) and AEP Texas (22.19%).

Marissa Gillett — former Chair of Connecticut's Public Utilities Regulatory Authority and now a senior fellow at the American Economic Liberties Project — said even before today's affordability crisis, customers expressed "feelings on a spectrum ranging from confusion to outrage regarding the size of utility profits."

During the webinar, Gillett said there are "four policy levers that can be utilized immediately to address the moment we're in," including dialing down artificially high return on equity rates, re-examining capital structures, modifying the ratemaking process to right-size utility profits and adding more consumer advocate voices to the ratemaking process.

She said anyone who hasn't historically participated in rate proceedings needs to become involved. She also said state commissions should be filled with qualified candidates.

Gillett said the country's investor-owned utilities are making for a "particularly extractive moment" because of "mismatched" incentives utilities receive for capital buildout. She said the return on equity drives utilities to build more, as evidenced by EEI *announcing* that utilities intend to spend $1.1 trillion over the next four years.

"Profits … are going to get higher if all of that capital investment enters into the utilities' rates," Gillett said.

Marx of EEI offered a different point of view. "There are standard calculations for evaluating regulated utility profits that appropriately recognize that most of a customer's bill reflects pass-through costs of service, but EPI instead took a simple but analytically weak and insufficient approach to intentionally mislead readers into believing that a high percentage of customer bills goes toward profits."

Brionté McCorkle, executive director at Georgia Conservation Voters, said consumers increasingly are spending higher shares of their income on utility bills. "That burden just continues to get worse as power bill continue to rise," she said.

McCorkle said her most recent Georgia Power bill was about $233, with roughly $52 of that for utility profit. "That is really high," she said. "It's not that they're raising these bills because it's necessary to keep the power on. They're raising these bills and they're padding their profits."

McCorkle said utilities are "incentivized to build even if the demand for energy never fully manifests." She said even if big capital expansions aren't prudent, utilities can take the investment risks while their rate base foots the bill.

"We're not just paying for what we build; we're also paying for the company to profit. … It's just not designed well," McCorkle said of the current setup.

McCorkle said the report helps "cut through the claims" that the increases are necessary to keep service reliable. She said utilities can still be profitable, "just not egregiously so."

Marc Brown, Consumer Energy Alliance vice president of state affairs, derided the EPI report.

"This report is connected to neither sound accounting nor reality," he said in an emailed statement. "The report's own disclaimer says that any output is an estimate that could fluctuate wildly, which is to say that fantasy football and uninformed guesses are more accurate."

He continued: "EPI is the three-card monte of so-called policy organizations. They want you to look elsewhere while remaining silent on state policies, which are responsible for as much as 40% of customer bills in some states. They ignore policies like net metering, which transfers wealth from the poor to the rich, and never offer solutions to failing market designs, which have resulted in future generating capacity shortfalls in PJM, MISO and NYISO."

"Additionally," he wrote in reference to Gillett, "one must question the credibility of an organization that casts doubt on others' motives while remaining shrouded in darkness as to who they represent. Especially when one considers that this line of attack comports with the thinking and behavior of their favorite disgraced state commissioner."

Ultimately, state regulators are charged with evaluating projects to ensure they're necessary and benefit customers. Those regulators determine what level of earnings is appropriate for utilities. ■

Northwest Lawmakers Explore Building Transmission Without BPA's Help

Ore., Wash. Legislators Seek to Create Transmission Authority

By Henrik Nilsson

Oregon and Washington lawmakers are exploring ways to build new transmission independent of the Bonneville Power Administration as electric sector stakeholders in the Pacific Northwest worry about the agency's struggle to build transmission fast enough to keep up with aggressive clean energy laws and increased load.

BPA paused certain planning processes in 2025 to consider how to address nearly 61 GW of transmission service requests. The agency presented several proposals to reduce the queue, but concerns have been raised that many of the efforts would go into effect after the 2030 deadline for utilities in Oregon and Washington to meet strict greenhouse gas standards.

Former BPA Administrator Randy Hardy has argued the issue lies with the states' respective clean energy laws, which he said set off a "gold rush" among developers, leaving BPA to solve the issue of building enough transmission to keep up. His comments received support from utilities and other organizations during BPA meetings. (See *BPA Tx Planning Overhaul Prompts Concern for Northwest Clean Energy Compliance*.)

Oregon state Rep. Mark Gamba (D) pushed back on that notion in an interview with *RTO Insider*.

Oregon's *House Bill 2021* directs the state's investor-owned utilities to reduce their greenhouse gas emissions by 80% by 2030, on the path to achieving 100% GHG-free generation by 2040. (See *Clean Energy, Equity Goals to Reshape Oregon IRP Process*.)

For Gamba, the issue is not the law's requirements but rather that BPA, which controls approximately 75% of the region's high-voltage transmission, has failed to build enough transmission.

"I'm less concerned with HB 2021 and the law as I am with the fact that we are still burning fossil fuels in the state of Oregon to supply energy to a rapidly growing load. That needs to come to a screeching halt," he said. "But the only way that's going to happen is if we build more transmission."

Aerial view of the Bonneville Dam | *Shutterstock*

Notable Quote

"We just need some entity to act like an adult in the room and actually start developing the transmission that we need.'

— Oregon Rep. Mark Gamba (D).

As a federal entity, BPA does not have to follow mandates imposed by the Oregon legislature. The agency has focused on its preference customers — publicly owned utilities that rely on it for generation — and failed to realize "they are the backbone of the transmission system in the whole Pacific Northwest," Gamba contended.

The situation worsened in 2025 after approximately 200 employees accepted a "deferred resignation" buyout offer under President Donald Trump's effort to slim down the federal government, according to Gamba.

BPA resumed hiring in September 2025. (See *BPA Looks to Fill 155 Positions After Hiring Freeze*.)

BPA declined to comment for this story, but the agency previously noted its efforts to build out transmission and generation.

For example, when BPA paused its transmission planning processes to deal with the 61 GW of generation in its current interconnection study, it identified 16 GW of late-stage projects that are being integrated at a rate of roughly 1 to 1.5 GW/year, with the goal of integrating the full 16 GW by 2035, according to the agency.

As for transmission, the agency secured $773.8 million in transmission capital for 2025 with the goal of doubling transmission capital execution by 2028. It plans to issue awards to contractors in March 2026 that will cover a 10-year period with a maximum value of $25 billion to build and modify lines.

BPA also launched its $5 billion Grid Expansion and Reinforcement Portfolio initiative in 2023 with the aim of building 23 new transmission lines and substation projects.

However, Gamba said BPA was "pretty nonresponsive" even before staffing cuts, adding he doubts the agency will "start building significant new lines anytime soon."

Instead, the Democratic lawmaker thinks Oregon should take matters into its own hands. Gamba presented a bill in 2025 aimed at creating a transmission authority (TA) and intends to revive that effort in 2026.

"We just need some entity to act like an adult in the room and actually start developing the transmission that we need," Gamba said.

The TA would explore where transmission is needed and begin the siting and permitting process. It then would work with utilities or third parties to get lines built. The approach has found success in New Mexico and Colorado, according to Gamba.

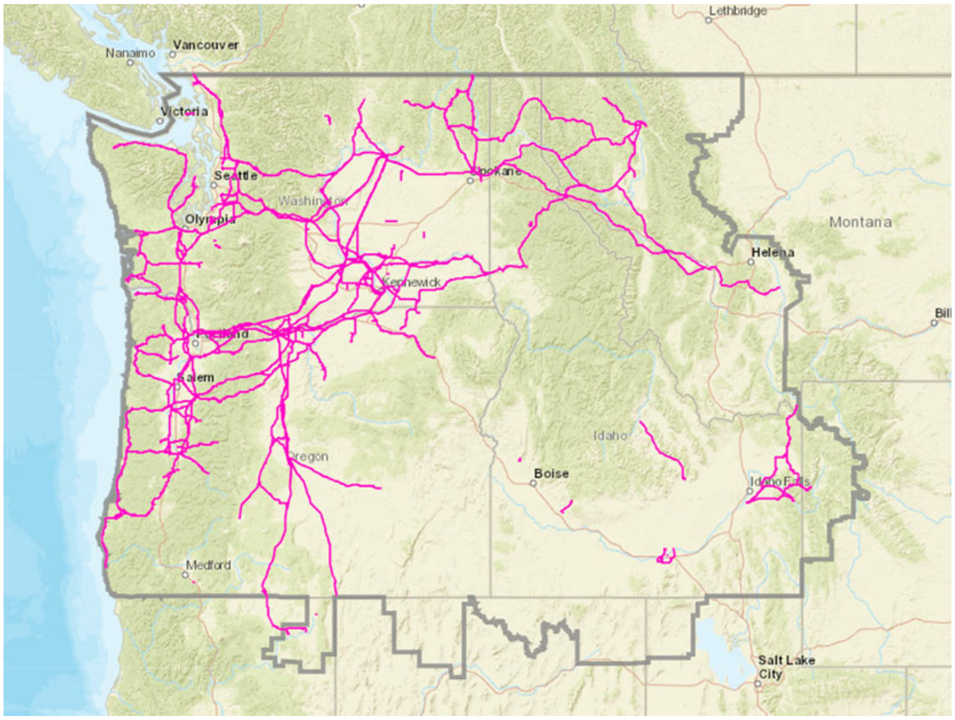
When asked about Gamba's initiative, Oregon Gov. Tina Kotek's office noted that the governor issued an executive order in November 2025 aimed at streamlining transmission siting and permitting approvals.

The order recognized that "a coordinated, statewide approach to planning and designating transmission corridors is essential to long-term infrastructure development that will support economic growth and ensure clean energy can be delivered efficiently and reliably to consumers."

The governor's office is working with the state's Department of Energy on developing the framework, which is expected to be completed in fall 2026 to support policy discussions next year, according to a spokesperson.

In an email to *RTO Insider*, JD Podlesnik, Portland General Electric's senior director of transmission delivery, said the utility is ready to work with BPA and other regional entities to expand transmission.

Podlesnik noted that PGE has added more than 3,000 MW of clean energy and storage to the grid and recently finalized agreements for an additional 1,000 MW of clean energy resources, "making steady progress toward customer-driven clean energy targets."



A map over BPA's transmission assets within the Pacific Northwest | *BPA*

"At the same time, transmission capacity remains a key challenge across the region, both for reliability and clean energy targets," Podlesnik said in the email. "BPA plays an important role in expanding the transmission network and accelerating the interconnection of new generation resources. Continuing to execute on BPA's Grid Expansion and Reinforcement Portfolio is one of the critical steps in addressing those constraints."

Washington Issues

Oregon entities are not alone in grappling with transmission constraints and compliance with clean energy laws. Washington utilities face a similar situation.

A study by Energy and Environmental Economics predicts that accelerated load growth and aging power plant retirements will create a resource gap in the Northwest starting at about 1.3 GW in 2026 and expanding to almost 9 GW by 2030. That is approximately the load of the state of Oregon.

For context, BPA's *White Book* released in May 2025 projected the Northwest would have about 27.9 aMW of total (not just federal) generation available in 2026.

As is the case nationwide, data centers and electric vehicles are the primary drivers behind the expected load growth.

And just as in Oregon, Washington's Clean Energy Transformation Act (CETA) requires all electric utilities in the state to become greenhouse gas-neutral by 2030 (allowing for use of offsets and other programs) on the way to generating all power from emissions-free resources by 2045. It also prohibits utilities from serving their Washington customers with any coal-fired generation after 2025. (See *Washington Agencies Adopt New Rules to Implement CETA*.)

But again, lack of transmission poses challenges for utilities to meet the law's requirements.

There is collaboration across state lines to build more transmission independent of BPA, according to Washington Rep. Alex Ramel (D).

Washington lawmakers also seek to create a transmission authority under *Senate Bill 6355*.

"There is this sort of federal government monopoly in the space," Ramel said.

Relying too much on the federal government as BPA struggles with staffing shortages "is a real concern," according to Ramel.

"That, to me, is part of the reason why we need to be more expeditious about how we think about putting together these kinds of projects," Ramel said in referring to a potential Washington TA. "Because if [BPA] is losing staff, that can only … impact negatively our need to be able to increase clean energy transmission opportunities."

As for CETA, Ramel said he is not ready to "pull the plug on it." He acknowledged the law was passed when the region did not have the same electricity use that comes with the development of AI and electric vehicles.

"I could be persuaded to have reasonable extensions or extenuating circumstances for utilities that really can't meet those goals," Ramel said. "But right now, I haven't seen anything that persuades me that those goals can't be met. We could revisit that in the future if we need to. Right now, I think we should stay full steam and let's build out clean energy and let's accelerate transmission."

Puget Sound Energy, which is one of BPA's largest transmission customers, has removed coal from its energy portfolio in accordance with CETA and is focused on providing 80% of its electricity from renewable or non-emitting resources by 2030-2033, according to Matt Steuerwalt, PSE's vice president of external affairs.

Still, BPA's ability to expand transmission capacity and allow new resources to come online "will have a major impact on our progress toward Washington clean energy laws," Steuerwalt told *RTO Insider*.

"We also have to consider permitting and siting for energy infrastructure development undertaken by entities other than BPA, which is a major challenge to building any project," he added. "We have been following the current legislation closely to see the extent to which it can address these and other issues."

'Morass of People'

But for Scott Simms, executive director of the Public Power Council, there are risks with creating separate TAs.

"I think that once you create an additional apparatus to try to do the exact same thing that other organizations are statutorily obligated to do, it's going to create a morass of people trying to all do the same things," Simms said.

Instead of solving the transmission challenges, the risk is that additional TAs would "exacerbate the very problem you're trying to solve," he added.

Rather, Oregon and Washington should fix the challenging operating environments they have created for consumer-owned and investor-owned utilities alike, Simms contended.

"There's a variety of things on both the energy policy side with regards to resources and there are fixes on the transmission side when it comes to permitting and the planning process," he said. "If the states were just to focus on how to best facilitate and streamline the transmission permitting and siting elements, that would be a huge help." ■

EDAM Governance Questioned During NV Energy Hearing

Powerex Attorney Grills CAISO VP About ROWE

By Elaine Goodman

As Nevada regulators consider NV Energy's request to join CAISO's Extended Day-Ahead Market, the debate over the independence of EDAM's governance has reached a critical point.

EDAM proponents and opponents shared their views during a Public Utilities Commission of Nevada hearing March 10. The parties also sounded off in written testimony and rebuttal comments filed with the PUCN in February. The commission is expected to vote April 3 on NV Energy's EDAM request.

"I recommend that the commission prioritize the independence of the market's governance over most other factors," David Patton, president of Potomac Economics, an independent market monitor for four RTOs/ISOs, said in written testimony filed on behalf of Powerex and Wynn Las Vegas, a luxury resort and NV Energy customer. Powerex has committed to joining SPP's Markets+, a competing day-ahead market.

Through the West-Wide Governance Pathways Initiative and California Assembly Bill 825 of 2025, governance of EDAM and CAISO's Western Energy Imbalance Market is being shifted to a Regional Organization for Western Energy (ROWE). Some see the ROWE as a means to alleviate concerns among potential market participants that CAISO, whose governing board is appointed by the California governor, plays too large a role in the markets' governance.

Patton said the ROWE is "a very positive step" in the governance of EDAM and WEIM. But he said the entity is proposed to have minimal staff and that "critical roles," including market operation, would remain with CAISO.

Why This Matters

If the Nevada PUC doesn't approve NV Energy's request to join EDAM, the day-ahead market could lose a large and central piece of its footprint.

NV Energy is waiting for Nevada regulators to approve its application to join CAISO's Extended Day-Ahead Market. | © *RTO Insider*

Lively Hearing

During the March 10 hearing, NV Energy representatives and intervenors in the case presented witnesses for questioning by the other parties in attendance. PUCN Chair Hayley Williamson presided over the session.

Attorney Curt Ledford with Davison Van Cleve grilled Stacey Crowley, CAISO's vice president of external affairs, about EDAM governance. Ledford represents Powerex and Wynn Las Vegas.

Ledford asked Crowley to read aloud Section 345.5(a) of the California Public Utilities Code, which directs CAISO to "conduct its operations … consistent with the interests of the people of the state."

"When you read 'the state,' do you understand [that to mean] the state of California, not the state of Nevada?" Ledford said.

"Correct," Crowley responded.

Ledford asked Crowley about the steps needed to establish the ROWE. While the ROWE has an interim board, it doesn't yet have staff. A consumer advocate office must be established, and a service agreement needs to be drawn up between the ROWE and CAISO. That agreement must be reviewed by the California Public Utilities Commission for conformance with AB 825 and likely will need FERC approval.

CAISO wants to wait until the permanent ROWE board is in place before negotiating the service contract, Crowley said.

"Would it be fair to say that this entire ROWE exercise could be for naught if CAISO doesn't pursue it?" Ledford asked.

Crowley disagreed.

"The [ROWE] could exist without California participation," she said, later clarifying that the ROWE "could take on other Western services if they so choose."

In response to Ledford's questioning, NV Energy attorney Roman Borisov asked Crowley whether the Pathways Launch Committee has the most control over the Pathways Initiative at this time. Crowley said yes, noting that the committee has broad representation from across the West and industry sectors.

Until the ROWE takes over governance, EDAM and WEIM are being overseen by the Western Energy Markets Governing Body, which has shared authority with the CAISO Board of Governors.

EDAM Choice Explained

NV Energy announced in May 2024 its intention to join EDAM rather than Markets+. The market choice requires PUCN approval, and NV Energy filed an application with the commission in October. (See *NV Energy Confirms Intent to Join CAISO's EDAM* and *NV Energy Files Request to Join EDAM*.)

Without NV Energy, EDAM would lose a large and central piece of its footprint.

David Rubin, NV Energy's federal energy policy director, said Section 345.5 of the California Public Utilities Code was adopted before CAISO was running a regional market. He noted that AB 825 added Section 345.6, which allows California utilities to participate in a CAISO market that has independent governance if the FERC tariff for the market includes a requirement to respect the authority of each participating state. That authority includes setting procurement, resource adequacy, environmental, reliability "and other public interest policies."

The language "reflects a clear recognition that the regional markets — including the EDAM — must accord equal respect to the policy interests of all participating states," Rubin said in written rebuttal testimony.

Rubin said market participants and regulators must have confidence in the overall fairness of a market's governance.

He said other key reasons why NV Energy chose EDAM are the company's positive experience in the WEIM; expected costs of day-ahead market implementation; EDAM's expected market footprint and interconnectivity of participants; and transmission work within the footprint that will enhance interconnectivity and supply diversity.

Additional reasons are EDAM's market design and projected financial, reliability and environmental benefits.

"These factors favor the EDAM over Markets+," he said. ■

N.M. Regulators Order Blackstone to Explain TXNM Stock Purchase

Issue Could Snarl Blackstone's Acquisition of PNM and TNMP

By Elaine Goodman

Why This Matters

PNM has seen a previous acquisition attempt from Avangrid crumble when the approval process got bogged down for too long.

In a potential hurdle to Blackstone Infrastructure's acquisition of TXNM Energy, state regulators have ordered Blackstone to provide legal justification for its purchase of 8 million shares of TXNM stock without the regulators' consent.

Two hearing officers with the New Mexico Public Regulation Commission on March 11 issued an *order to show cause* related to the stock purchase. The order starts an investigation but does not determine whether any violations occurred.

TXNM and Blackstone Infrastructure announced in May 2025 Blackstone's proposed $11.5 billion purchase of TXNM, the parent company of Public Service Company of New Mexico (PNM) and Texas-New Mexico Power (TNMP). Under the proposal, TXNM would be acquired by Blackstone Infrastructure subsidiary Troy Parent Co.

In June 2025, Troy TopCo LP, which owns Troy Parent, closed on a deal to buy 8 million shares of TXNM stock for $400 million. The stock purchase made Troy TopCo TXNM's third-largest shareholder, with about a 7.59% ownership, according to filings in the case.

On Feb. 6, Prosperity Works filed a *motion* asking the commission to look more closely at the stock purchase. On its website, the group says its mission is to promote "economic prosperity for all New Mexicans."

Prosperity Works argued that under New Mexico Statutes section 62-6-12, buying stock of a public utility or holding company requires PRC approval if the purchase is for the purpose of acquiring a public utility or holding company. Without commission approval, the purchase "shall be void and of no effect," the statute states.

In their response, TXNM and Blackstone said the statute applies only to transactions that result in a change in control of a public utility or holding company. They said the stock purchase was a financing transaction separate from the proposed acquisition.

The PRC hearing officers' order said Blackstone's response does not fully address Priority Works' concerns.

"Further inquiry is necessary to ensure that the joint applicants have properly adhered to the statutory obligations presented in Section 62-6-12," the hearing officers said in their order. TXNM and Blackstone must show why the stock purchase didn't violate state law and, if a violation did occur, what the legal and practical implications are.

Blackstone and TXNM are required to file briefs by April 6. Other parties in the case may also file comments by that date, and responses are due by April 20. Hearing examiners will then hold a hearing.

Among parties formally supporting Prosperity Works' motion is the New Mexico Department of Justice, which filed a brief in the case Feb. 19.

A large crowd turned out for a New Mexico PRC public comment session on Feb. 5, with many speakers opposed to Blackstone's proposed purchase of PNM. | *New Mexico PRC*

"State law requires oversight when public utility stock is issued in connection with a transaction like this," Attorney General Raul Torrez said in a statement. "We are asking the commission to ensure that all legal requirements are satisfied and that the public interest remains the guiding priority."

Other supporters include New Energy Economy, the New Mexico Consumer Protection Alliance, the Coalition for Clean Affordable Energy and PRC staff.

Blackstone's bid to buy TXNM Energy comes after a previous attempt to buy PNM failed. Avangrid announced in January 2024 that it was pulling out of its proposed $8.3 billion acquisition of PNM Resources, as the deal remained tied up at the New Mexico Supreme Court. (See *Lights out for Avangrid's PNM Acquisition*.)

As part of the proposed Blackstone acquisition, PNM would provide $175 million in benefits to customers and the state — including a $105 million acquisition rate credit, the companies said in August 2025. PNM said the acquisition would help it meet key goals, including transitioning to clean energy, modernizing and hardening the grid, and building new transmission. (See *PNM Seeks Approval for Blackstone Acquisition*.)

The acquisition has received approval from the Public Utility Commission of Texas and TXNM Energy shareholders. FERC approved the deal in February. (See *FERC Approves Blackstone's $11.5B Acquisition of PNM*.)

The acquisition still needs approval from the Nuclear Regulatory Commission and the New Mexico PRC. ■

EDAM Utilities Moving to Develop RA Program

Letter to Regulators Signals How Backers Plan to Proceed with Effort

By Robert Mullin

The push to develop a resource adequacy program serving non-CAISO members of the ISO's Extended Day-Ahead Market appears to be gathering momentum, with backers saying they aim to produce a draft design for the program in April.

That's a key takeaway from a March 7 *letter* to the leaders of the CAISO Western Energy Markets (WEM) Body of State Regulators (BOSR), in which six utilities planning to join the EDAM spelled out the clearest vision yet for how the program could take shape: on the footing of the ISO's Western Energy Imbalance Market.

"The WEIM's proven ability to support reliable load service makes it a natural foundation for exploring an expanded framework through EDAM and an integrated RA solution," the utilities said in the letter, which was signed by Mike Wilding, PacifiCorp vice president of energy supply management, on behalf of PacifiCorp, Balancing Authority of Northern California, NV Energy, Portland General Electric (PGE), Public Service Company of New Mexico (PNM) and Turlock Irrigation District.

The letter was addressed to BOSR Chair Gabriel Aguilera, chair of the New Mexico Public Regulation Commission, and Vice Chair John Hammond, a member of the Idaho Public Utilities Commission.

"A voluntary regional RA program aligned with an organized market footprint is expected to deliver value in several areas, including enhanced regional coordination, greater reliability and capacity savings for our customers," Wilding wrote.

Why This Matters

The EDAM utilities' letter to state regulators signals how they plan to develop an alternative to the Western Resource Adequacy Program.

NV Energy is one of the utilities that signed on to the March 7 letter spelling out plans to develop an EDAM RA program. | © *RTO Insider*

The letter comes nearly five months after a handful of utilities — including NV Energy, PacifiCorp, PGE and PNM — announced their intent to withdraw from the Western Power Pool's Western Resource Adequacy Program (WRAP), choosing not to commit to the program's first "binding" season in winter 2027. (See *PacifiCorp Next to Leave WRAP After Raising Concerns.*)

The WRAP, which was conceived and established before the competition between the EDAM and SPP's Markets+, is operated by SPP but includes members intending to participate in either day-ahead market — although Markets+ members are required to join it.

Around the same time as the withdrawals, *RTO Insider* learned some of the withdrawing parties had already begun discussions to create an alternative RA program focused on EDAM participants. (See *EDAM Participants Exploring Potential New Western RA Program.*)

Wilding said the utilities envision the "offering to encompass the EDAM and WEIM footprint," and noted they foresee it being governed by the Regional Organization for Western Energy (ROWE), the independent body established by the West-Wide Governance Pathways to oversee the WEIM and EDAM. (See *Pathways' ROWE Could Offer Western RA Program, PGE Says.*)

"During the transition, the entities identified [in the letter], all of which are committed to EDAM or leaning toward EDAM, propose to guide the stakeholder process and encourage engagement from all interested parties. We recognize the importance of this initiative, but it is important to note that no official commitments or decisions have been made at this time," he wrote.

The utilities welcome input from "state regulators, load-serving entities, suppliers and regional partners" as the initiative advances, Wilding wrote.

The effort's backers intend to release "a draft design for a market-integrated solution" in April and "launch an open transitional stakeholder process to refine the program." The first step will be to start dialogue during the WEM Regional Issues Forum meeting March 16, the letter said. The RA program is also on a March 19 meeting agenda of the ROWE's newly established Formation Committee.

"The West faces a transformational moment. By building on the successes of WEIM and EDAM, we all have the opportunity to create a unified framework that advances reliability, affordability, regional transparency and regulatory goals," Wilding wrote. ■

CAISO Developing Large Loads Technical Standards

Straw Proposal Expected in April

By David Krause

| Microsoft

Although large loads are not new to California or the West, CAISO is now formulating technical standards that address their potential boom over the coming years.

Developing the standards is a critical step to ensure artificial intelligence data center and electric vehicle large loads will reliably and safely interconnect to CAISO's grid. The ISO established a working group on the issue in 2025 and opened a new large loads *initiative* Feb. 27.

"Large loads are a topic of extreme urgency and interest lately, especially with the emergence of artificial intelligence," Danielle Mills, CAISO principal of infrastructure policy development, said at a March 10 workshop. "But we also consider large loads to be more than just data centers and AI. While data centers do present the largest use case, we are also looking at things like electric vehicle charging, electrification of buildings, and industrial processes and agricultural processes and the like."

CAISO's 2025/26 transmission plan shows 4.5 GW of data center capacity online now, with an additional 1.8 GW added by 2030 and 4.9 GW more by 2040.

"We do proactively plan for these types of large loads through the integrated planning process with the California Energy Commission," Mills said. "We are always trying to stay ahead of any new demand for large loads, but we are aware that this is really dynamic space right now and that we are seeing increasing numbers of large load interconnection service applications at the utilities."

Notable Quote

"Our mission is to ensure large loads continue to draw power from the grid during and following grid disturbances."

— CAISO's Ebrahim Rahimi

CAISO is developing a definition of what constitutes a large load and new requirements for voltage and frequency ride-throughs, along with setting limits on rapid ramping and pulsating load levels. (See *CAISO Examines 'Pulsating' Data Center Loads*.)

One topic of concern is how large loads consume power or reduce load during grid disturbances, such as during a post-fault active power recovery (PFAPR) moment.

"Our mission is to ensure large loads continue to draw power from the grid during and following grid disturbances," Ebrahim Rahimi, CAISO senior adviser for transmission planning, said at the workshop.

During a PFAPR, large loads will be allowed to reduce their power consumption during and immediately after severe faults, Rahimi said. However, after the fault is cleared and voltage returns to normal, the power consumption from the grid should be required to recover to — or close to — pre-disturbance levels within a given time, Rahimi said.

Another concern is persistent small load fluctuations. Even modest but continuous fluctuations in load can produce voltage flicker or unacceptable variations in local power quality, CAISO staff said in a large loads issue *paper*.

Over time, these load fluctuations might increase mechanical fatigue in equipment, such as in rotating machines and transformers. Requirements will need to ensure that persistent small-signal load variations remain within acceptable limits, staff said.

CAISO is also following NERC's formulation of national standards for large loads, such as for computation loads from AI training centers. Rahimi said those standards will be ready for approval at the end of 2026, and NERC is planning a large load Level 3 alert in May or June.

NERC issued a Level 2 alert on the issue in 2025 and soon will release a related report. (See *Panelists Say More Work Needed on Large Load Risks*.)

CAISO has not yet decided where large load technical requirements will ultimately be documented and enforced, he said.

"Although we are coming up with these technical requirements … how these requirements will be documented has not been decided at this point," Rahimi said. "The whole idea is to come up with these requirements and ensure reliability, and then at a later stage a decision will be made about where to document them."

CAISO plans to publish a straw proposal in April that includes technical requirements, transmission service offerings and cost-allocation methods for large loads. ■

CEC Seeks to Tap EV Battery Capacity for Grid

Agency Looks to Install 18,000 Bidirectional Chargers as EV Capacity Exceeds Stationary Storage

By David Krause

California's historic battery storage boom over the past five years has not kept up with the state's electric vehicle capacity growth — and now officials want to send idle EV electrons back to buildings, homes and the grid through new bidirectional chargers.

At the end of 2025, EV capacity in California reached 18.5 GW, which is more than a third of the historical peak load recorded in CAISO, Vincent Weyl, CEC principal of fuels and transportation, said at a March 12 CEC voting meeting. That figure also exceeds the state's total stationary storage capacity of about 17 GW, including behind-the-meter storage and utility-scale storage, Weyl said.

"The opportunity and potential of bidirectional [charging] is massive and presents benefits to EV owners, grid operators and ratepayers," Weyl said. "Of course, this resource can only be accessed when the vehicle is not driving and when the vehicle is located where bidirectional charging is possible."

EVs could serve about 10% of California's total residential load, he added.

The CEC has funded 200 bidirectional charging stations to date and is developing a program that could fund up to 18,000 new bidirectional chargers, Weyl said.

The CEC's bidirectional charging research project is the first time a state agency has assessed the benefits of bidirectional charging for the grid, the driver and electricity consumers, CEC Commissioner Nancy Skinner said at the meeting. But much more work needs to happen for these chargers to proliferate, she said.

Many changes to rate structures and how equipment connects to the grid are needed to "compensate someone for using their EV to send power to the grid," Skinner said.

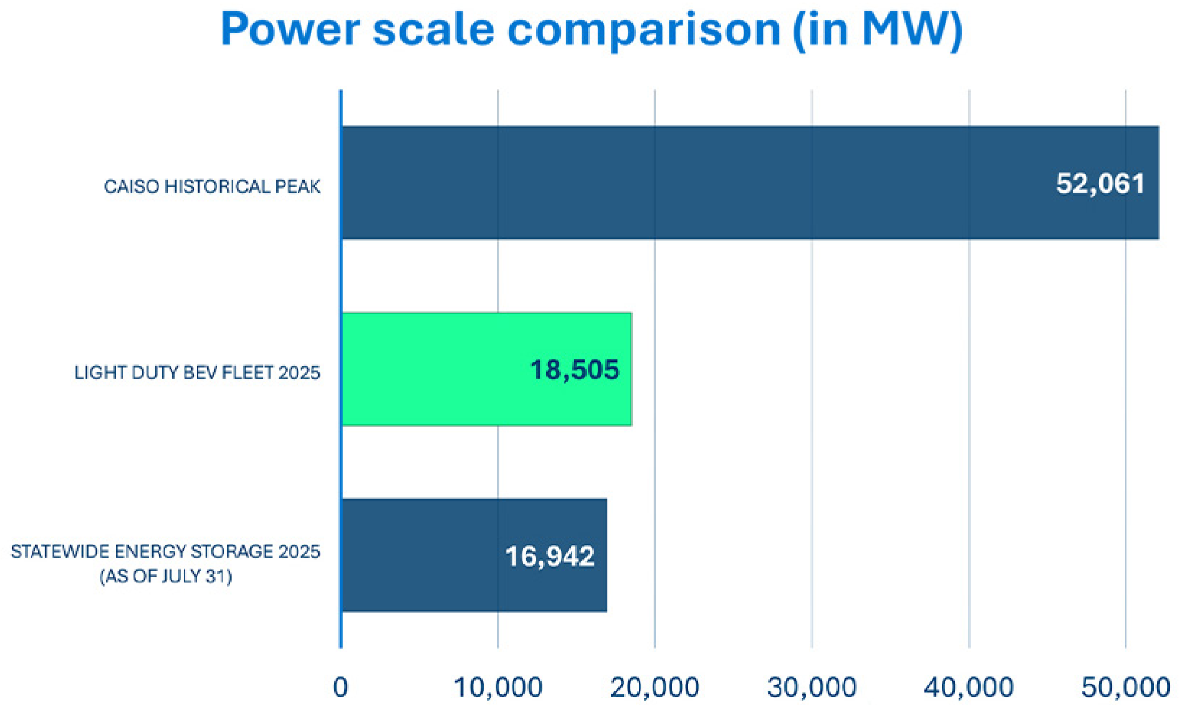
More than half the EVs studied could participate at least weekly in a discharge event during peak hours, CEC staff found in their research. This charging frequency would reduce EV owners' electricity bills an average of $260 to $320 from June to September.

"It is incredible how much power we have roaming around on our streets," Commissioner Andrew McAllister said at the meeting. "If we can take advantage of even a small percentage of that at the margin, that is going to make a huge difference in our reliability profile."

But the concept of connecting EVs to the grid has been around for more than 10 years at California's energy agencies. In 2014, CAISO published a vehicle-to-grid road map *report* with support from the CEC and the California Public Utilities Commission. More recently, in February 2026, the CPUC in a *resolution* asked Pacific Gas and Electric to demonstrate how bidirectional EVs and electric vehicle supply equipment can provide community resiliency benefits during grid outages.

At the voting meeting, the CEC also approved Riverside Public Utilities' (RPU) integrated resource plan. The City of Riverside plans to procure its electricity from only zero-carbon sources by 2040 and retire its gas-fired plants by the same year. Currently, about 30% of RPU's electricity is generated by geothermal resources.

RPU's annual demand is expected to increase from about 2,300 GWh in 2025 to more than 3,250 GWh in 2045. ■



This graph shows that light-duty EVs in California currently contain 18,505 MW of capacity, which is more than all of the stationary battery storage capacity in the state. | *CEC*

APS to Seek Palo Verde Extension through 2067

Nuclear Plant Would Join Others Approved to Run for 80 Years

By Elaine Goodman


Palo Verde Generating Station | *APS*

Arizona Public Service has notified the U.S. Nuclear Regulatory Commission that it plans to seek operating license renewals for all three units at Palo Verde Generating Station, potentially extending operations through the mid-2060s.

APS filed a notice of intent with the NRC on March 13, saying it will submit a Subsequent License Renewal application in late 2027. The renewal would allow Palo Verde units 1, 2 and 3 to run through 2065, 2066 and 2067 respectively.

NRC approval would extend the units' life to a total of 80 years. APS noted that the NRC so far has renewed licenses for 80 years of operation to 10 nuclear plants across the U.S.

The three Palo Verde units, with a combined capacity of 4.2 GW, are a key piece of APS's long-term energy strategy and central to Arizona's grid reliability, the company said in a release.

"Our notice to the NRC is another step in ensuring Arizonans and the region continue to benefit from this critical resource for many more years to come," APS CEO Ted Geisler said in a statement.

Units 1, 2 and 3 received their initial 40-year operating licenses from the NRC in 1985, 1986 and 1987, respectively. In 2011, the NRC approved APS' request to extend the operating licenses for 20 years, through the mid-2040s.

Palo Verde is operated by APS and supplies electricity to Arizona, Texas, New Mexico and Southern California. It is owned by seven utilities: APS, El Paso Electric, Los Angeles Department of Water and Power, Public Service Company of New Mexico, Salt River Project, Southern California Edison and Southern California Public Power Authority.

Why This Matters

With demand growth surging across the U.S., a growing number of nuclear power plants are seeking license extensions from the Nuclear Regulatory Commission.

Through its "subsequent license renewal" (SLR) process, the NRC conducts safety and environmental reviews for extending nuclear power plant operations for up to 80 years of operation. Public meetings are part of the process.

In addition to approved applications, the NRC is reviewing three SLR applications. Those include Units 1 and 2 of Florida Power & Light's St. Lucie plant; Unit 2 of Duke Energy's H.B. Robinson power plant in South Carolina; and Units 1 and 2 of the Edwin I. Hatch nuclear plant in Georgia. NRC also has a pipeline of notices of intent to file SLR applications.

Among the 10 nuclear plants that have been approved for 80 years of operation are Florida Power & Light's Turkey Point Units 3 and 4. The approval, received in 2024, allows the units to run through 2052 and 2053.

Units 2 and 3 of Peach Bottom Atomic Power Station, co-owned and operated by Constellation Energy Generation in York County, Pennsylvania, received approval to operate through 2033 and 2034.

Arizona's Nuclear Future

Besides seeking license extensions for Palo Verde, APS has teamed up with two other Arizona utilities — Salt River Project and Tucson Electric Power — to explore additional nuclear generation in the state. In 2025, they applied for a U.S. Department of Energy grant to evaluate potential nuclear sites. (See *Arizona Electric Utilities Team Up to Pursue Nuclear*.)

The funding is available through the Generation III+ Small Modular Reactor *program* in the DOE's Office of Clean Energy Demonstrations. The utilities are applying for funding in the "fast follower" category, which will provide up to $100 million to address hurdles the U.S. nuclear industry has faced in areas such as design, licensing, supply chain and site preparation. Awardees must match the DOE funding.

Tier 1 award recipients were announced in November 2025. (See *DOE Awards Holtec, TVA $800M to Build Pioneering SMRs*.)

Tier 2 applicants, including APS, are still waiting to hear if they'll receive funding. But initial project planning has begun, including the hiring of a project manager, APS Senior Director Brad Berles told the Arizona Corporation Commission during a February workshop on nuclear power.

APS continues to evaluate nuclear technologies and hasn't yet settled on a specific option.

"We know there's a large demand growth that we need to meet," Berles said. ■

Texas PUC Proposes Large Load Interconnection Standards

Commission Gets Update on ERCOT Batch Process

By Tom Kleckner

The Texas Public Utility Commission filed a *proposed rule change* that would establish interconnection standards for large load customers and support business development while maintaining system reliability.

The rule would require large load customers to execute an intermediate agreement that makes certain disclosures before their inclusion in an interconnection study and to post $50,000/MW in financial security. No later than 30 days after the study, the customers would have to execute an interconnection agreement that updates their disclosures and pay a nonrefundable $50,000/MW interconnection fee (*58481*).

Staff originally recommended $100,000/MW fees, but the commissioners agreed during their March 12 open meeting to cut them in half. PUC Chair Thomas Gleeson said while he supported staff's attempt to end the planning restudy cycle caused by speculative large load projects with the fees, they could "deter otherwise-viable development."

"The $100,000/MW threshold may unintentionally create a barrier to market entry for all but the largest hyperscalers in the world, even if these smaller companies have viable, tangible projects under development," he said in a *memo* filed before the meeting.

The rule would set consequences should a large load customer withdraw all or a portion of requested peak demand or contracted peak demand and for failing to reach schedule milestones in their phased energization. It would also establish a refund of financial security when a large load energizes.

Market participants and other stakeholders can file comments until April 17.

The commissioners and staff also discussed a proposed rule for *net metering arrangements* involving a large load co-located with an existing generation resource. The proposal would establish study criteria, set procedural steps for ERCOT and the PUC to follow, and identify a non-exhaustive list of conditions the commission can impose (*58479*).

The proposal will be brought up for consideration at the PUC's next open meeting March 26.

ERCOT Files Batch 0 Revisions

ERCOT staff told the PUC they are responding to stakeholder comments on their proposed changes to the large load interconnection process incorporating batch, or cluster, studies (*59142*).

Jeff Billo, ERCOT vice president of interconnection and grid analysis, told the PUC that staff will file comments to a protocol change (*NPRR1325*) and a Planning Guide revision (*PGRR145*) that would set up the transitional Batch 0 process. The PGRR would establish the criteria to determine which large load interconnection requests already in progress will be included in the first batch study, while the NPRR lays out how the study would be performed and the transmission plan compiled.

Staff held a fourth workshop on the batch process March 10, and a fifth is scheduled for March 24. ERCOT has also launched a follow-up stakeholder survey to gather additional input.

"We are continuing to engage with stakeholders," Billo said.

He said staff hope to file additional revision requests early in April that target the roles of bring your own generation and controllable load resources in the batch studies. That would allow them to be brought before the ERCOT Board of Directors in June along with the Batch 0 revisions.

Caldwell Load Joins Texas Grid

ERCOT successfully transitioned the city of Caldwell's municipal utility from MISO to its system March 12. The PUC approved the move in 2025 (*57517*).

The city will continue to serve its residential, business and industrial customers. The Lower Colorado River Authority is responsible for the transmission system that connects Caldwell to the ERCOT grid.

ERCOT staff lay out their proposed interconnection standards for large loads. | *AdminMonitor*

Caldwell, located about 80 miles northeast of Austin, adds about 14 MW of load to the system.

"This transition reflects strong collaboration between the city of Caldwell, the [PUC] and ERCOT to ensure a smooth integration into the ERCOT system," CEO Pablo Vegas said in a *statement*.

Oncor Project Approved

The PUC *approved* Oncor's $118.8 million Rockhound Switch-Connell Switch project — a 345-kV double-circuit transmission line less than 20 miles long — and related substation work outside Midland's city limits (*58519*).

Oncor expects to complete construction and energize the facilities by August 2027. The project was approved by ERCOT's board in December.

In other actions, the commission:

- clarified its final order in El Paso Electric's rate case, *finding* that distributed generation customers whose interconnection applications were accepted after a 2017 order will be subject to the new rate approved by the PUC (*57568*). (See "PUC Rejects EPE Cost Recovery for Newman," *ERCOT Promises More Details on Batch Study Process*.)
- assessed $578,916 in penalties, payable to the PUC, for violations of failing to submit required emergency operations plans and other violations in 11 separate dockets (*58883*, *58954*, *58995*, *59005*, *59017*, *59030*, *59060*, *59065*, *59110*, *59127* and *59301*). ■

Abbott Appoints Rhode to Texas PUC as 5th Member

By Tom Kleckner

Texas Gov. Greg Abbott has *appointed* former infrastructure developer Patrick Rhode to the state's Public Utility Commission, bringing the agency to its full five-person complement.

Rhode's term expires Sept. 1, 2027, and is effective April 1, according to Abbott's March 12 announcement.

Rhode spent 16 years as vice president of corporate affairs for *Cintra*, which develops and manages energy, highway and airport infrastructure projects in North America. He founded his own eponymous *public relations consulting firm* in Austin in 2024 and serves as its president.

Patrick Rhode will join the Texas PUC on April 1. His appointment will be subject to Senate confirmation. | *Patrick Rhode Strategies*

He is credited with helping secure and protect more than $10 billion in "new age" infrastructure projects and managing diverse policy climates at federal and state government levels.

The Advanced Power Alliance, which represents advanced generation projects, welcomed Rhode's appointment. The APA said his career has been defined by "navigating complex institutions" and "demonstrating a seasoned understanding of how public policy, regulatory environments and private investment" work together.

"Texas is home to more power generation investment than anywhere else in the country, and that investment … is the product of a regulatory environment that is stable, predictable and focused on positive outcomes for Texas consumers and the Texas economy," APA President Jeffrey Clark said in a *statement*. "A strong, reliable, affordable electric grid requires all of these technologies working together, and the commission plays an essential role in ensuring the conditions are in place for diverse energy investment to continue.

"We are confident that Commissioner Rhode understands the stakes."

Patrick Rhode Strategies works with organizations to help manage commercial development support, government and public affairs, political risk and strategic communications.

Before he joined Cintra, Rhode was a special assistant to President George W. Bush, associate administrator of the Small Business Administration and senior adviser to NASA, and he held senior roles in the Department of Homeland Security after Sept. 11, 2001. He began his career in television reporting for CBS and ABC affiliates.

An Arkansas native, Rhode holds bachelor's degrees in political science from the University of Arkansas and in communications from the University of Arkansas at Little Rock.

The PUC's membership was changed from three commissioners to five after the disastrous 2021 winter storm that brought the ERCOT grid to its knees. Besides the electricity sector, the commission regulates the state's water, wastewater and telecommunications utility industries. ■

AI's Rapid Growth Increases Risks to U.S. Grid

By Tom Kleckner

Artificial intelligence has been *framed* by the Trump administration as ushering in a "new golden age of human flourishing, economic competitiveness and national security" for the U.S. should it win the race for computing systems that perform tasks normally requiring human intelligence.

But with the country's drive to build up its AI ecosystem comes increased risks, both digital and physical.

Faruk Dziho, the business intelligence analyst and data solutions lead for the Texas Reliability Entity, says that while AI can strengthen grid reliability, it also creates risks if it is not managed properly.

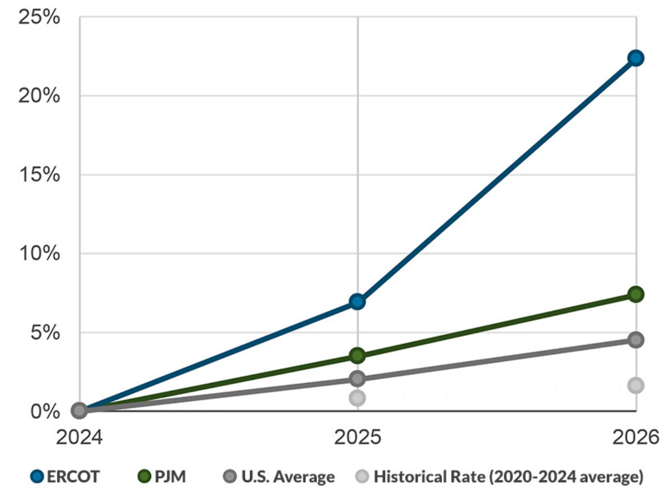
"At the end of the day, it's just a tool, and it's not a replacement for engineers or operators. It excels at pattern recognition and forecasting when there is clean data," he said during a Talk with Texas RE webinar March 10. "When it comes to some risk-mitigation strategies, there needs to be a robust data governance in building high-quality data pipelines with clear ownership, extensive validation model transparency and oversight."

The Bottom Line

The government's drive to build up its artificial intelligence ecosystem comes with increased risks, according to the Texas RE.

Texas RE added AI integration as a "moderate" risk in its 2024 *Reliability Performance and Regional Risk Assessment*, released in June 2025, saying the risks are "currently relatively unlikely to manifest themselves."

"As AI increases in scale and integration, however, associated risks may increase in both likelihood and impact," the regional entity wrote.



The EIA expects demand to grow quickly in Texas, which will increase the risks from AI integration. | *Texas RE*

"That assessment itself is not set in stone. As adoption expands across the industry, both the probability and severity of those risks may rise," Dziho said. "We'll continue to monitor developments and adjust the assessments as the technology evolves."

The Texas Interconnection grew faster than any other region in 2025, with demand increasing 5% through September when compared to the same period in 2024, *according* to the U.S. Energy Information Administration. The agency has said it expects demand to increase by more than 9% in 2026.

Dziho told his online audience that AI carries risks that demand robust mitigation strategies. AI-driven load growth could lead to cybersecurity vulnerabilities that can be exploited faster with AI-powered tools and systems, adaptive malicious code that bypasses security controls, and data poisoning.

"Artificial intelligence basically makes it easier for attackers to generate phishing attacks by generating thousands of personalized emails instantly or scanning for vulnerabilities faster," he said.

Because AI systems use massive amounts of data collection and typically include confidential and/or sensitive information, data privacy controls must be effective in reducing the risk of breaches, Dziho said.

"We need to secure artificial intelligence workflows," he said. "The field is changing constantly. There are new threats that we find out daily." ■

ISO-NE Proposes Cut to Performance Payment Rate

By Jon Lamson

ISO-NE has *proposed* to reduce its performance payment rate (PPR) by more than 60% in response to concerns that excessive penalties will have unintended consequences for the capacity market.

Capacity resources in New England have incurred significant performance penalties during scarcity events over the past two years. These penalties have been particularly consequential for slower-start fossil units. Over two events in 2024, net penalties for combined cycle gas and oil generators totaled $44.3 million, while penalties for steam turbine residual-oil units totaled $25.8 million.

Some participants have argued the risk of these penalties could drive up capacity prices in future auctions and push resources out of the market.

The performance rate determines penalties and credits during scarcity events. The RTO's Pay-for-Performance (PFP) construct is designed to insulate ratepayers, with underperforming resources paying for the incentives for overperforming resources.

The RTO's per-megawatt-hour performance rate has grown in recent years, increasing from $2,000 to $3,500 in 2021, to $5,455 in 2024, and to $9,337 in 2025.

ISO-NE announced at the NEPOOL Markets Committee meeting March 10 that it plans to cut the rate back to $3,500. It also plans to move forward on an expedited schedule to implement the changes as quickly as possible, targeting a technical committee vote in May.

"Some resources may find the increased PPR, and the volatility associated with it, makes the risks and potential costs of selling capacity too high," said Chris Geissler, director of economic analysis at ISO-NE. "This could result in retirements from resources that can still make meaningful contributions to system reliability."

He added that a high performance rate increases the risk that individual resources hit their stop-loss limits, which cap the total penalties each resource can accrue per month. When resources hit this limit, ISO-NE charges unrecovered penalties to all capacity resources that have not hit the stop-loss limit.

The reduced PPR still should provide adequate incentives for performance, Geissler said, estimating that incentives from PFP and elevated energy market prices likely would total around $6,000/MWh.


Newington Station in Newington, N.H. | *Granite Shore Power*

Also at the Meeting

ISO-NE discussed proposed changes to its treatment of exports during scarcity events and detailed its compliance with a January FERC order requiring the RTO to cap its Pay-for-Performance balancing ratio at 1.0.

"History suggests that resources make investments and perform strongly at this rate," he said.

Stakeholders generally reacted favorably to the proposal, while some expressed concern that a $3,500 rate may be too low to adequately incent performance during scarcity conditions.

Treatment of Exports

Also at the MC meeting, ISO-NE *detailed* its plans to subject certain exports to the performance rate.

This change, recommended by both of the RTO's market monitors, is intended to prevent a market loophole that could allow participants to earn performance credits without sending any power.

Under the current rules, during a capacity scarcity event, if a participant schedules exports that equal imports scheduled by a different participant, the export would not be charged performance penalties, but the import would earn performance credits.

"These two transactions collectively result in no power flowing but do not net in settlement because they are submitted by different market participants," said Enrico De Magistris, economist at ISO-NE. "The market participants could transact outside the ISO-NE system to share the PFP credits."

He noted that ISO-NE is not aware of any instances in which a participant has exploited this loophole.

To fix the issue, the RTO proposes to charge the performance rate during scarcity conditions to all exports "not associated with a specific generator in the ISO-NE system."

Unlike "system-backed exports," exports associated with a specific generator would not be charged the performance rate. These exports would reduce the amount of performance revenues the associated generator could earn or subject it to performance penalties for not meeting its capacity supply obligation (CSO).

De Magistris said ISO-NE likely will remove system-backed exports from the calculation of its balancing ratio, which it uses to determine capacity resources' obligations during scarcity events.

ISO-NE calculates the systemwide balancing ratio by dividing load and reserve requirements by total CSO. System-backed exports are currently included in the calculation as load, while generator-backed exports are excluded.

Balancing Ratio Cap

ISO-NE also discussed its proposal to cap the PPR balancing ratio in compliance with an order issued by FERC in January.

The ruling stemmed from a complaint by the New England Power Generators Association after the balancing ratio exceeded 1.0 for the first time ever during an event in June (*EL25-106*). (See *FERC Directs ISO-NE to Cap Pay-for-Performance Balancing Ratio at 1.0*.)

In designing the tariff changes, ISO-NE has tried to "keep the 'effective' payment rate for overperformance as close to the tariff-specified [PPR] as possible," said Megan Sweitzer, lead analyst at ISO-NE.

Under the proposal, if the cap on the balancing ratio leads to the under-collection of performance charges, this deficit would cut into the performance credits allocated to overperforming resources.

"This change ensures resources performing at their CSO megawattage are not charged" and "lowers the 'effective' PPR for overperformance when a deficiency exists," Sweitzer said.

Notably, the treatment of deficits caused by the balancing ratio cap would differ from the treatment of deficiencies caused by the stop-loss mechanism, which will still be charged to all capacity resources.

While NEPGA argued against ISO-NE's allocation of stopped losses in its complaint, FERC sided with ISO-NE's argument that the stop-loss mechanism benefits all capacity resources and therefore it is fair to charge capacity resources for the costs of its implementation. ■

FERC Opens Show Cause Proceeding into ISO-NE Rules for Improper Payments

By Jon Lamson

FERC has initiated a show cause proceeding based on concerns about the lack of provisions in the RTO's tariff enabling fixes to incorrect payments to or from market participants.

The order, issued March 10, comes following multiple recent requests from participants for waivers to return improperly accrued funds to the RTO.

The commission wrote the ISO-NE tariff "appears to be unjust and unreasonable because it lacks provisions that would enable ISO-NE to return amounts that it erroneously charged to market participants and to accept payments from market participants that were erroneously or improperly received in ISO-NE's markets."

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

FERC established settlement procedures in 2024 for a waiver request by Canal Marketing to return improperly accrued funds from the RTO's Inventoried Energy Program. The commission approved a settlement between ISO-NE and Canal in early 2025. (See *FERC Establishes Settlement Procedures for ISO-NE IEP Exit Request*.)

In fall 2025, Brookfield Renewable Trading and Marketing requested a waiver to refund ISO-NE for four months of improperly received capacity market revenues. FERC established settlement proceedings for this waiver request on the same date as its show cause order.

ISO-NE has 60 days to justify its existing tariff rules or explain what changes it would make if FERC requires it to make tariff changes addressing the issue.

"If ISO-NE prefers to propose revisions to the tariff on the subject of this order, then it may do so pursuant to its applicable [Federal Power Act] Section 205 filing rights," FERC added. ■

ISO-NE Details Initial Forecast of Capacity Auction Reforms' Effects

By Jon Lamson

ISO-NE has published *initial data* on how its proposed capacity market overhaul will affect resource accreditation, providing an indication of how the changes would affect capacity market revenues for different resource types.

The RTO presented the long-awaited impact analysis results to the NEPOOL Markets Committee on March 12. Reacting to the findings, several stakeholders expressed concern about the expected negative effects on storage, solar and demand response resources.

ISO-NE cautioned it has yet to finalize the proposed market changes and stressed the results do not reflect the effects of winter gas system constraints, which could significantly affect market outcomes in the winter season. The region should get a clearer picture of the potential effects when the RTO presents additional analysis in the coming months.

The Capacity Auction Reforms (CAR) project, intended to take effect in time for the 2028/29 capacity commitment period (CCP), would establish a new capacity accreditation framework; split annual commitment periods into six-month sea-

Comparison of Accreditation Share (MRIC vs. QC)

	CAR-SA MRIC (summer)		CAR-SA MRIC (winter)		Current Rule QC	
	MW	System share (%)	MW	System share (%)	MW	System share (%)
Gas-only	7,362	26.90%	7,857*	30.10%	7,873	24.20%
Oil/Dual-Fuel (Thermal)	8,635	31.60%	8,956	34.30%	10,500	32.30%
Daily/Weekly Hydro	1,013	3.70%	1,020	3.90%	1,062	3.30%
Other Thermal (including Nuclear)	3,430	12.50%	3,520	13.50%	3,922	12.10%
Imports	2,018	7.40%	1,177	4.50%	2,205	6.80%
Oil/Dual-Fuel (EL3)	764	2.80%	685	2.60%	798	2.50%
Energy Storage (PSH + Batteries)	2,141	7.80%	810	3.10%	3,862	11.60%
Hybrids	534	2.00%	264	1.00%	644	1.30%
IPR - Wind	503	1.80%	912	3.50%	565	1.40%
IPR-Solar	340	1.20%	100	0.40%	566	0.40%
IPR-Hydro	228	0.80%	336	1.30%	316	1.00%
IPR - Others	218	0.80%	216	0.80%	232	0.70%
ADCR	179	0.70%	231	0.90%	761	2.30%
Total	**27,362**		**26,083**		**33,305**	
System-weighted rMRI		**73.80%**		**69.2%**		

Estimated effects of CAR changes on capacity share by resource type | *ISO-NE* sons; and cut the time between auctions and CCPs from more than three years to about one month.

The accreditation and seasonal changes would directly affect how much capacity each resource can sell in the market.

The RTO currently accredits resources based on a "qualified capacity" framework that does not account for factors including intermittency, fuel limitations and resource outage rates. Under the CAR proposal, ISO-NE would accredit resources based on their modeled ability to reduce energy shortfall. Accreditation values would be subject to change on an annual and seasonal basis depending on shifts in the characteristics of energy supply and demand in the region.

The timing and length of modeled shortall events would be significant factors in determining accreditation values. For example, short-duration storage would be more valuable for preventing short-duration shortfall events, while intermittent resources would be better at mitigating shortfalls that coincide with their production profile. Because of the dynamic nature of the modeling, adding large amounts of intermittent resources with similar production profiles would reduce the accreditation values of all like resources by reducing the chances of shortfall occurring while they are expected to be performing.

For the 2028/29 CCP, ISO-NE's modeling estimated the median summer shortfall duration to be about three hours and the median winter duration to be about five hours.

ISO-NE plans to calculate accreditation values based on performance during marginal reliability impact (MRI) hours, which it defines as "hours where additional available capacity would reduce unserved energy in that hour or in a subsequent hour."

MRI hours include periods of energy shortfall; when storage would be dispatched to avoid unserved energy; and when storage would be unable to charge. Enabling storage conservation or charging can reduce expected shortfall in subsequent hours, ISO-NE noted.

"While summer EUE [expected unserved energy] events last about three hours on average, incorporating the associated dispatch and charging hours shows that total MRI events are considerably longer — averaging roughly nine hours," said Chris Geissler, director of economic analysis at ISO-NE. "Similar to summer, MRI event duration during winter is also longer than EUE events, with an average of 21 hours."

Why This Matters

If implemented as currently designed, ISO-NE's capacity market changes could lead to a significant reduction in revenue available to storage, solar and demand response resources.

The impact analysis shows a reduction in total systemwide capacity under the proposed rule changes. ISO-NE has not forecast how the changes would affect revenues but did estimate how the proposal would affect each resource type's share of total system capacity.

The near-term results indicate an increase in capacity share for nuclear, non-intermittent hydro, wind, storage-limited oil and dual-fuel resources, and passive DR including energy efficiency.

In contrast, ISO-NE projected significant declines in capacity share for storage, solar and active DR resources.

For storage resources, duration would have a significant effect on capacity value. ISO-NE estimated the reliability value of a four-hour battery to be about twice the value of a two-hour battery in the summer and winter. For wind and solar, offshore wind performed better than onshore in both seasons, and sun-tracking solar outperformed fixed.

Accreditation values varied significantly by season for many resource types. Hydro, wind and oil resources with large storage capacity performed better in the winter, while imports, energy storage and solar performed better in the summer.

ISO-NE forecasts an increased capacity share for gas-only resources in both seasons, with a higher share in the winter because of higher maximum capabilities amid low temperatures.

However, the gas-only results may be misleading, as they do not account for winter pipeline constraints, which can be a major limiting factor for these resources. ISO-NE plans to account for these limitations through a separate "gas capacity demand curve," which would reduce the winter capacity clearing price for gas-only resources that lack firm fuel arrangements. (See *ISO-NE Introduces Approach to Modeling Gas Constraints*.)

ISO-NE's longer-term analysis indicated that adding significant amounts of solar and wind would decrease the per-megawatt reliability value of incremental additions of these resources. For wind resources, the addition of 2,000 MW of capacity in 2035 reduced the reliability benefit of additional wind by about 20% in the winter and more than 40% in the summer.

Several participants expressed concern that ISO-NE is overestimating winter risks — including the duration of winter events — causing accreditation reductions for batteries and solar.

"As the accreditation results currently stand, the design will fail to send investment signals for renewables, demand response and energy storage to participate in New England's capacity market," said Alex Lawton, director at Advanced Energy United. "That will deter new supply from entering the market and put upward pressure on electricity prices as demand continues to grow."

He said the impacts of the new gas demand curve remain a "major unknown," but this "won't solve the core problem of severely undervaluing advanced energy technologies."

Lawton added that he remains "optimistic that the ISO will consider stakeholder feedback, run other scenarios in their model, and make changes that reflect realistic conditions and market behavior so that real system risk drives accreditation, not modeling choices."

ISO-NE plans to present the results of two additional longer-term modeling cases in April. In May, the RTO plans to discuss the results of an analysis focused on the effects on market clearing outcomes. Outputs of this analysis will include estimates of clearing prices, consumer costs and capacity revenues by resource type. ■

Vineyard Completes Construction, Revolution Starts Generation

By John Cropley

One New England offshore wind farm has completed construction, and another has begun sending electricity ashore as it finishes construction.

With a combined nameplate capacity of 1,510 MW, *Vineyard Wind* and *Revolution Wind* are expected to provide an important boost to the ISO-NE grid.

But both projects have faced delays and interference reaching their respective milestones, including two federal stop-work orders each — one from equipment problems, and three as part of the Trump administration's ongoing campaign against offshore wind development. Whether the administration might take steps against completed wind farms remains to be seen.

Vineyard announced installation of the final turbine blades the evening of March 13, marking the completion of offshore construction.

Also on March 13, Revolution announced it had begun delivering electricity. Coincidentally, that date was the deadline for the Trump administration to appeal a federal judge's Jan. 12 stay of a Bureau of Ocean Energy Management stop-work order against Revolution. BOEM did not appeal.

Vineyard put its first steel in the water in June 2023 and exported its first electricity to Massachusetts in January 2024. But the 806-MW project took a sharp turn for the worse later that year when a blade disintegrated, showering debris into the oceans and then onto beaches.

Why This Matters

The two offshore wind projects, which have dealt with delays and interference from the Trump administration, are expected to provide an important boost to the ISO-NE grid.

Work on the Revolution Wind project is shown in June 2024. The facility delivered its first power to the New England grid March 13. | *Ørsted*

An investigation revealed manufacturing flaws; work was slowed or halted while replacement blades were installed.

The 65-turbine, 704-MW Revolution Wind began construction in 2023 but ran into cascading delays even before President Donald Trump returned to office. Then late in 2025, as the project was nearing completion, BOEM shut it down along with the four other projects under active construction in U.S. waters.

One by one, judges lifted all of those stop-work orders. (See *With Sunrise Wind Ruling, OSW Industry now 5-0 Against Trump Admin*.)

Now that electrons have begun flowing to Connecticut and Rhode Island, Revolution will be scaling up generation in the days and weeks to come, an Ørsted spokesperson said March 16.

An ISO-NE spokesperson said March 16 that Revolution is one more asset for a region that needs new power resources: "Last week, Revolution Wind delivered power to New England's regional grid, as part of the commissioning and testing process. Through the wholesale markets administered by the ISO, Revolution Wind has committed to helping meet New England's demand for electricity, which is forecasted to grow approximately 11% over the next decade."

Vineyard and Revolution would not say how much electricity they are sending ashore, and ISO-NE said it could not, citing confidentiality rules. An industry advocate previously said Vineyard sent as much as 600 MW to the strained New England grid during a major winter storm in January.

As of 5 p.m. March 16, the RTO's *ISO Express* dashboard indicated wind turbines were producing a total of 1,066 MW, or 66% of the renewable resource mix. System load was 14,473 MW.

Natural gas (6,735 MW) and nuclear (3,358 MW) accounted for the bulk of resources. Net imports (1,623 MW) were a bit ahead of wind power, and hydro (982 MW) was a bit behind.

In 2025, wind provided *4,618 GWh of electricity* to the ISO-NE grid, which was 4.1% of generation and 3.9% of net energy for load. Solar was slightly higher: 4,836 GWh, 4.3% and 4.1%, respectively.

U.S. Sen. Sheldon Whitehouse (D-R.I.) *was among those cheering the news* about Revolution powering up.

"When Rhode Island families pay their utility bills, they will be grateful to Ørsted and the resilient union workers who got this project over the finish line," said Whitehouse, who brought a *union apprentice electrician* helping build Revolution to Trump's 2026 State of the Union Address. "Power from Revolution Wind will make our grid more reliable in the winter and reduce Rhode Islanders' energy costs for years to come." ■

Mass. Gov. Healey Issues Order to Procure 10 GW of Power by 2035

By Jon Lamson

Amid uncertainty about how New England will meet rising demand in the coming decades, Massachusetts Gov. Maura Healey (D) issued an *executive order* to procure 10 GW of new power and 5 GW of energy storage by 2035.

In the *announcement* of the order on March 16, the administration claimed the procurement would save customers $10 billion and bashed President Donald Trump's "costly war and his failed energy policies."

While the state has set ambitious clean energy targets and invested heavily in its offshore wind supply chain and infrastructure, the Trump administration's attacks on offshore wind have left the industry in a precarious position with an unclear long-term outlook.

In the days leading up to the order, Revolution Wind announced first power and Vineyard Wind 1 installed the final turbine on its long-delayed project. (See related story *Vineyard Completes Construction, Revolution Starts Generation*.) But the next wave of large projects has been sidetracked for the foreseeable future and policymakers have been forced to look elsewhere for sources of power to meet growing demand.

Possibilities for this next wave of supply could include onshore wind in northern Maine, offshore wind in Nova Scotia and advanced nuclear. While pipeline constraints limit the region's ability to add large amounts of gas-fired generation, gas plants could look to add dual-fuel capabilities enabling them to burn oil in the winter when pipelines are constrained.

Gov. Maura Healey | © *RTO Insider*

Why This Matters

ISO-NE forecasts demand growth to accelerate over the next decade and has expressed concern about potential resource adequacy issues in the 2030s.

"I believe in an all-of-the-above approach to energy — that means solar, wind, gas, nuclear and hydro," Healey said in a statement. "While the president is taking American-built energy sources off the table, in Massachusetts, we are saying yes to more supply from more sources of energy."

The executive order stipulates that 4 GW of the procurement should be solar power and 3.5 GW should be demand management. The final 2.5 GW could include New England-based generation and imports to the region.

The executive action includes a list of high-level directives to state agencies aimed at promoting clean energy technologies including solar, wind, geothermal, nuclear and demand response.

It explicitly references the expiring Inflation Reduction Act tax credits for wind and solar and the need to move quickly to meet the deadlines. Projects must begin construction by July 4, 2026, or come online by the end of 2027 to receive the federal incentives.

The order also directs the Department of Public Utilities to review the state's natural gas and oil storage and delivery capabilities, and "identify whether additional, strategically located storage capacity or delivery capabilities could provide reliability and affordability benefits to all ratepayers and align with existing regulations."

However, it does not call for the expansion of fossil fuel systems — such as pipeline infrastructure — into the state.

The wide-ranging order:

- Directs the Executive Office of Energy and Environmental Affairs to "review and expedite" existing initiatives to promote the development of renewables and storage; address barriers to interconnection; and expedite regulatory proceedings affecting solar development.

- directs the Department of Energy Resources to conduct a review of existing demand management programs;
- promotes efforts to develop next-generation nuclear resources and directs the EEA to accelerate efforts to support existing nuclear resources;
- directs the EEA to "accelerate deployment of geothermal and other non-fossil thermal energy systems" by reducing administrative and regulatory barriers, increasing worker training and collaborating with companies and unions to address supply chain constraints;
- requires utilities to submit plans to manage increased interconnection requests as developers push projects to meet federal tax credit deadlines;
- directs utilities to establish flexible interconnection programs; and
- directs the DPU to "expedite the review of proposals that can unlock the benefits of time-of-use electricity rates, distributed energy resources, energy efficiency and virtual power plants."

Reactions

While right-wing groups in the state have frequently derided the Healey administration for favoritism toward renewable resources, the administration has tended to emphasize stakeholder consensus when developing energy policy. The announcement of the order included testimonials from a range of business, clean energy, labor and environmental organizations.

"Action like this is exactly what the commonwealth needs to ensure we remain a place where everyone can afford to live," said Brooke Thomson, CEO of the Associated Industries of Massachusetts.

"Setting clear targets to bring 10 GW of new energy online, along with major new investments in storage, will help strengthen reliability and ensure the region has the power it needs to meet growing demand," said Valessa Souter-Kline of Advanced Energy United.

"Massachusetts needs more reliable energy and more union jobs — and we need them quickly," said Chrissy Lynch, president of the Massachusetts AFL-CIO. "Working families shouldn't have to purchase energy from billionaire oil tycoons and foreign governments."

"We applaud Gov. Healey's focus on lowering energy costs and her long-held principle that customers shouldn't be forced to subsidize costly and polluting fossil fuel infrastructure," said Caitlin Peale Sloan of the Conservation Law Foundation. ■

MISO's 3rd Expedited Queue: 8 GW of Gas and Batteries

By Amanda Durish Cook

MISO announced a third, 8-GW cycle of generation projects to enter its fast-tracked interconnection process, its largest cluster yet.

MISO's expedited interconnection queue continued its theme of a high proportion of thermal resources, with gas plants *outnumbering* storage facilities on a capacity basis 5.8 GW to 2.2 GW. Storage accounted for eight entries, while gas submittals took the remaining seven slots.

In its second 15-count queue class, gas also tipped the scales and accounted for 4.3 GW of the 6-GW group. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

The grid operator said it expects this collection of projects to be in service no later than 2031.

This batch of expedited interconnections includes Northern Indiana Public Services Co.'s coal-to-gas transition at its R.M. Schahfer Generating Station. NIPSCO submitted two combined-cycle plants totaling 2,639 MW. NIPSCO cited its 2024 integrated resource plan to back up the need for the plants, which was developed before the U.S. Department of Energy stepped in to prevent the Schahfer plant from retiring as planned at the end of 2025.

The Schahfer plant is on emergency stay-open orders through March 23. So far, DOE hasn't let any of its 90-day operating extensions lapse, issuing a chain of orders before the last has a chance to expire. Schahfer also needs expensive, time-consuming repairs before the plant's Unit 18 can function. (See *Enviros Warn NIPSCO Against Rebuilding Coal Unit on DOE Emergency Order*.)

Work on a BESS facility in Coldwater, Mich., in 2025 | *Motor City Electric Utilities*

NIPSCO also put forward 500 MW of battery storage at its Mitchell site in Gary, Ind. NIPSCO said both the Schahfer gas plants and Mitchell battery storage "are necessary for resource adequacy to serve growing data center, advanced manufacturing and other economic development project load requirements."

Xcel Energy, DTE Electric, NextEra Energy, Swift Energy Storage, Hackett Energy Storage and Brickyard Energy Storage also submitted battery facility plans ranging from 100 to 300 MW in Michigan, Minnesota and Indiana.

Xcel Energy's plans included its Sherco South BESS project, part of the utility's *planned* Sherco Energy Hub in central Minnesota, which reimagines the site around the coal-fired Sherburne County Generating Plant (Sherco) into a solar and storage format. Xcel closed Sherco Unit 2 in 2023 and plans to idle units 1 and 3 in 2026 and 2030, respectively.

Gas plans, on the other hand, involve one of Entergy Louisiana's three plants to serve the sprawling Meta data center in Richland Parish, a 478-MW plan from Entergy Texas, and Basin Electric Power Cooperative's 250-MW turbine in South Dakota.

Gas submittals from Alliant Energy subsidiaries Interstate Power and Light Co. for a 750-MW plant in north-central Iowa and Wisconsin Power and Light Co. for a 150-MW turbine addition in eastern Wisconsin also made the cut.

"The interest we continue to see reflects both the urgency and the opportunity to develop a clear, timely path to interconnection, and [the Expedited Resource Addition Study] is helping us provide that in the near term," Vice President of System Planning Aubrey Johnson said of the batch of applicants.

MISO said that, to date, its queue fast lane has attracted 53 applicants representing almost 27 GW of nameplate capacity, which the RTO has either agreed to study or awaits approval.

The RTO said it has completed studies on more than 11 GW of proposed capacity and the developers behind the first 10 projects already have struck generator interconnection agreements.

MISO's temporary queue express lane is capped at 68 projects, and MISO said it will entertain the last project submissions through mid-2027 before the process winds down on Aug. 31, 2027, if not sooner.

Johnson said the queue fast lane is part of MISO's larger work to get its regular interconnection queue unstuck and pick up the pace on achieving a one-year processing timeline.

Express Lane Dropouts

Developers have withdrawn eight projects since the fast-tracked interconnection lane opened in 2025.

The most recent projects to drop off are two NextEra battery storage projects in Hoosier Energy's territory. NextEra withdrew its 275-MW Sandcut and 400-MW Merom four-hour storage projects in mid-February. They were meant to serve a Solvenz data center.

NextEra also shelved its expedited request for its restart of the Duane Arnold nuclear plant in Iowa. The plant is set to rumble back to life by early 2029. Google signed a 25-year deal to buy power from the plant in October 2025. By November 2025, NextEra withdrew its fast-track request, though *plans* to restart the plant remain.

Alliant Energy's Interstate Power and Light Co. also scrapped its request for expedited processing on a planned, 950-MW natural gas plant near Duane Arnold in November.

MISO confirmed to *RTO Insider* that any projects it lists as "withdrawn" were withdrawn by their respective developers.

The RTO also said it allows other developers to take the place of withdrawn projects only if it can be done quickly. The grid operator said it doesn't backfill fast lane spots if the developer doesn't withdraw its project before it begins its round of studies. ■

Industry Seeks Immediate Halt to Con Edison Storage Policy

Groups Say Batteries not Economical Under New Rules

By John Cropley

New York energy storage and solar trade groups are seeking an immediate end to what they say is an effective freeze on interconnection of distributed storage facilities by the state's largest investor-owned utility.

The New York Battery and Energy Storage Technology Consortium (NY-BEST) and New York Solar Energy Industries Association (NYSEIA) filed a *petition for emergency rulemaking* March 11 asking the Public Service Commission to restrict Consolidated Edison from applying an "unlawful and arbitrary" review standard for New York City storage projects.

They charge that Con Edison's review process was implemented without legal justification, is causing irreparable harm to the storage industry and is exacerbating grid reliability concerns in the region. There was no need to change the way storage is studied under the state's Standardized Interconnection Requirements, they argue, but if such a need did exist, there are much better ways to address it.

The utility stood by its actions.

"Con Edison supports battery storage as a critical part of New York's clean energy transition, and the rapid growth in applications reflects strong market momentum," Vice President for Distributed Resource Integration Raghu Sudhakara told *RTO Insider* via email March 11. He added, however, that the sector's expansion must be carried out in a way that does not shift new infrastructure costs onto the utility's ratepayers.

The disagreement has been fermenting for months, and it spans PSC cases on energy storage (*18-E-0130*), distributed generation and storage (*24-E-0621*) and New York City reliability needs (*25-E-0764*).

NYISO and the PSC both have identified grid reliability risks looming in and near New York City, and both have taken steps to address it. (See *N.Y. PSC Directs Con Edison to Create Plan to Avert Energy Shortfall*.)

Why This Matters

The regulatory tussle will help determine how much energy storage is built in New York City and who bears the cost.

Battery energy storage systems (BESS), with their dispatchable output and lack of on-site emissions, are one of the potential solutions in the densely populated region; over 2,000 MW of capacity have been proposed.

On Aug. 15, 2025, Con Edison notified developers that it had placed on hold all BESS proposals seeking interconnection at seven constrained substations. It added 21 more substations to the list Sept. 16.

NY-BEST on Jan. 13 *petitioned the PSC* for "urgent action" on the utility's move. It supported its *call for immediate relief* from Con Edison's new restrictions on BESS interconnection with a *white paper* outlining suggested changes in interconnection and market rules to better enable storage to provide maximum value to the grid.

The infrastructure upgrade requirements resulting from Con Edison's changes to the Coordinated Electric System Interconnection Review rendered most of the energy storage projects proposed in New York City economically unviable, NY-BEST said.

The organization also flagged the "fundamental misalignment between utility financial incentives and New York's energy affordability goals": A utility earns a regulated rate of return on capital expenses such as infrastructure upgrades, but not for facilitating third-party BESS interconnections.

The PSC on Feb. 20 *solicited public comment* on the petition but took no action to change or limit Con Edison's practice.

On Jan. 14, *Con Edison told the PSC* there were 115 MW of operational BESS and 865 MW with executed interconnection agreements in the utility's service area as of Dec. 31. But the interconnection queue for BESS proposals with 5 MW or less capacity had reached 2,500 MW, up 300% in two years.

That is a quarter of its 10-GW peak load in 2024, Con Edison wrote.

A problem, it said, was that the BESS proposals were being concentrated in areas with less expensive land and more favorable zoning — 65% of the storage megawatts in the queue would be supplied by just 10 of the company's 63 substations. More than 20 substations were at or near hosting limits.

Because BESS typically would seek to recharge overnight, full buildout would make night peaks exceed daytime peaks and require new infrastructure that otherwise would not have to be built. Con Edison sought to put the developers on the hook for the resulting costs, which it said could run in the $100 million to $1 billion-plus range.

"As the market scales, storage must deliver real benefits to customers — not drive new infrastructure costs that show up on bills — which is why we are working with regulators and stakeholders to align growth with real-world grid conditions preserving grid reliability while also protecting affordability," Sudhakara explained. "Without reforms, current policies risk shifting significant new costs to customers, undermining both affordability and the long-term success of storage."

NY-BEST and NYSEIA in their petition attempt over the course of 26 pages to punch holes in the legality, accuracy and necessity of Con Edison's steps to carry out the priorities Sudhakara cited.

They ask the PSC for an emergency rule to immediately block Con Edison from using the restrictive requirements for distributed storage applications and keep the ruling in place while it considers NY-BEST's Jan. 13 petition. ■

NYISO Stakeholders Discuss Cluster Study, System and Resource Outlook

By Vincent Gabrielle

| © RTO Insider

RENSSELAER, N.Y. — Following the intense discussions of the reliability planning process reforms earlier in March, NYISO's Electrical System Planning Working Group/Transmission Planning Advisory Subcommittee discussed modest updates to several ongoing *projects* at its March 9 meeting.

Incremental tariff *revisions* to the cluster study enhancements project are intended to improve the interconnection process by reducing the administrative burden on applicants, said Thinh Nguyen, senior manager of interconnection projects. The overall goal is to decrease disputes and withdrawals from the interconnection queue.

NYISO also presented the most recent update to the 2025-2044 System and Resource Outlook study. The final report is due the second quarter of 2026 and forecasts system conditions over 20 years. Preliminary results, posted in January 2026, *found* increased load growth and generation in New York with less reliance on imports. NYISO also asked stakeholders for feedback on potential sensitivity *cases*.

Stakeholders asked for more clarification on how NYISO arrived at its assumptions for nuclear capacity in the study and questioned if the scenario, which predicts several gigawatts of new nuclear in the capital region, was accurate. Stakeholders said most of the interest in nuclear has been concentrated in the northern part of the state near Oswego. They were also uncertain if the ISO's assumptions for downstate hydrogen production were realistic.

Sarah Carkner, NYISO manager for long-term assessments, said the notion new nuclear capacity could come online by 2038 was based on publicly available data for lead times and that 12 years seemed to be the soonest.

Lastly, NYISO presented a *modification* to its FERC Order 1920 compliance. Instead of the previously proposed timeline that would have created four to five year gaps in the rollout of System and Resource Outlook Studies, NYISO will perform the study every three years and have it align with New York's coordinated grid planning process. ■

Monitor Urges PJM to Make Data Centers Bear Grid Burden

Points to Risks in 'Complex Regulatory Structures' that Could Shift Costs to Consumers

By Michael Brooks

PJM's Independent Market Monitor warned that the cost of wholesale power in the RTO will continue to rise with the rapid addition of data center load without enough capacity to serve it.

According to the Monitor's State of the Market *report* for 2025, released March 12, PJM's total cost of power rose nearly 49%, from $55.52/MWh in 2024 to $82.67/MWh in 2025. Of that, the cost of capacity rose 262%, from $3.61 to $13.09, after two Base Residual Auctions that saw record clearing prices.

The second capacity auction, held in December for 2027/28, procured 6.6 GW less than PJM's Region Reliability Requirement. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement* and *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

"Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices," the Monitor wrote. "But for data center growth, both actual and forecast, the capacity market would not have seen the same tight supply demand conditions; the same high prices observed in the 2025/26 BRA [held in 2024], the 2026/27 BRA and the 2027/28 BRA; and the currently expected tight supply conditions and high prices for subsequent capacity auctions."

Notable Quote

"Really the only purpose of running this backstop auction is for data centers that have not managed or don't want to be involved in negotiating bilateral contracts with generation developers to meet their demand."

— PJM IMM Joe Bowring

In both the report and in a teleconference with reporters, Monitor Joe Bowring blasted PJM for "continuing to simply accept the interconnection of large data center loads that cannot be served reliably because there is not adequate dispatchable capacity."

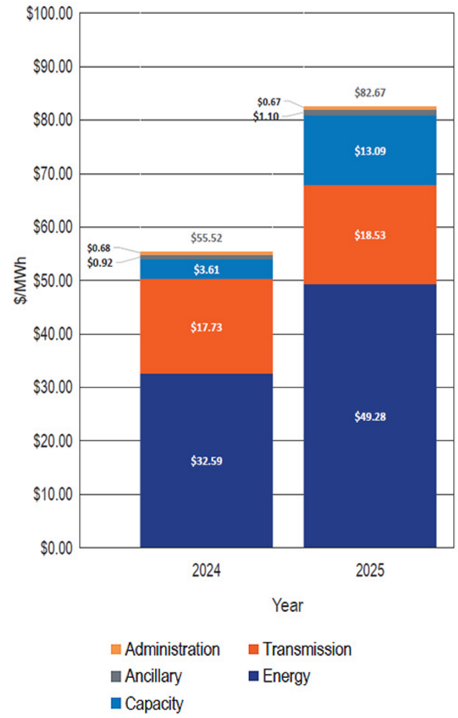
"But the consensus seems to have moved to, 'Well, let's interconnect them, but let's curtail them whenever that capacity is needed by other customers,'" Bowring told reporters. "That's easier said than done."

The high capacity prices have had a direct effect on retail prices, with ratepayers seeing spikes beginning June 1, 2025. "Just a simple fact," Bowring said. "There's been a lot of attempts to confuse the issue. … It is entirely about data centers."

The Monitor urged changes to the capacity market to account for data center load before the next BRA in June. It also argued that its proposal for the reliability backstop auction, instigated by the governors of PJM's member states and the White House, is the only one consistent with both the principles laid out by the government and the Ratepayer Protection Pledge signed by several large tech companies.

Those documents "establish two essential core principles: that the data centers must bear their own costs and risks and not shift them to other customers, and that the data centers must bring their own new generation in any one of a number of forms or be fully curtailable," the Monitor wrote. "The temptation to create complex regulatory structures to shift data center costs and risks to other customers should be resisted. … Other PJM customers, whether residential, commercial or industrial, should not be treated as a free source of insurance for data centers."

Bowring was blunter on the teleconference: "Really the only purpose of running this backstop auction is for data centers that have not managed or don't want to be involved in negotiating bilateral contracts with generation developers to meet their demand."



The total cost of wholesale power in PJM in 2024 and 2025 | *Monitoring Analytics*

A reporter asked about data centers' opposition to long-term bilateral contracts with utilities, as they argue load forecasts are uncertain. Instead, they want PJM to act as the counterparty for a predetermined amount of capacity in the backstop auction. (See *PJM Plans to Release Reliability Backstop Design in April*.)

"I mean, think about what that's saying: that individual data centers don't know what their demand is?" Bowring replied. "That's not a plausible statement. I think part of what the data centers are doing is trying to make things sound more confusing than they are in order to avoid taking responsibility for their load."

Making the RTO a counterparty "makes every other customer in PJM a source of free insurance for the data centers, which is ironic because these are some of the biggest, most profitable companies in the world," he said. ■

Virginia Legislature Wraps Up, Passes Clean Energy Bills

By James Downing

The Virginia Legislature wrapped up its main session with Democrats taking advantage of a wider margin in the House of Delegates and recently elected Gov. Abigail Spanberger (D) to push through bills favoring clean energy.

"The General Assembly has passed a slate of legislation squarely focused on making life less expensive for Virginians," Spanberger said in a March 14 statement. "I'm particularly proud to see lawmakers pass our entire Affordable Virginia Agenda to drive down housing, health care and energy costs for Virginians across our Commonwealth. High costs are top of mind in every community — and our agenda directly responds to those concerns."

She's reviewing the legislation, which awaits her signature, with an eye toward advancing her affordability agenda, the governor added.

"We have a governor now, who got sworn in shortly after the session started here, too, who's more supportive of clean energy solutions than her predecessor," Advanced Energy United's State Lead for Virginia Jim Purekal said. "'Her' predecessor — I like saying that, right? And, also, this governor is more engaged with the General Assembly than her predecessor was."

While Democrats grew their majority in the House, the commonwealth staggers its state elections, so the Senate was unchanged, he added.

House Bill 397 and Senate Bill 809 are companion bills that require state agencies to develop regulations around re-entering the Regional Greenhouse Gas Initiative, which Spanberger called for after Virginia pulled out of the cap-and-trade market under previous Gov. Glenn Youngkin (R). (See *Va. Air Board Approves RGGI Withdrawal*.)

"For me, this is about cost savings. RGGI generated hundreds of millions of dollars for Virginia — dollars that went directly to flood mitigation, energy efficiency programs and lowering bills for families who need help most," Spanberger said in a speech shortly after taking office in January. "Withdrawing from RGGI did not lower energy costs. In fact, the opposite happened — it just took money out of Virginia's pocket. It is time to fix that mistake."

Why This Matters

Democrats pushed through policies favoring solar and storage, but the growing demand from data centers requires more firm capacity as Virginia's business is dominated by facilities serving the cloud that have around-the-clock demand.

Virginia State Capitol in Richmond, Va. | *Virginia Department of Historic Resources*

The legislature passed *HB 895*, which requires Dominion Energy to procure at least 16 GW of short-duration batteries (with 10 or less hours of storage) and 4 GW of long-duration batteries (greater than 10 hours) by 2045.

Other bills are meant to grow solar's role in Virginia, with *HB 711* requiring localities to review projects adequately before they can reject them and *HB 807* expanding the shared solar program for Dominion.

While Dominion has gotten approval for one natural gas plant through the State Corporation Commission and has plans for more in its integrated resource plan, Purekal said the focus of Democrats who control the government is on affordability and clean energy.

"We're seeing a greater appetite for affordable options, and so that's where the clean energy solutions really come into play," Purekal said. "Because, you know, 10 years ago, we weren't able to have this conversation about clean energy solutions. We're seeing pivotal and drastic drops in cost now for solar and for storage and for wind. But we're primarily talking about solar storage, really."

Solar and storage are the fastest resources to deploy on a system seeing substantial demand growth from data centers, he added.

If Virginia doesn't build its own natural gas plants, it will rely on imports from other states in PJM that are interested in building the facilities, said Stephen Haner. Haner is a former lobbyist who got to know energy policy in Virginia by working for Newport News Shipbuilding and now writes for the web publication *Bacon's Rebellion*.

"There's nothing passing that would ease the path for gas," Haner said. "There are a number of things passing that create new impediments to gas. They're rewriting the entire Integrated Resource Plan statute."

HB 429 would amend the IRP process by requiring the use of the social cost of carbon and limiting Dominion's options for flexibility around the Virginia Clean Economy Act, he added. It passed both houses on the session's final day.

Rejoining RGGI when the states that historically shipped excess power east in PJM are not joining will lead to leakage, Haner said.

"You can see the pattern for the years before we were in RGGI," he added. "You see one output for Dominion plants in the three years in RGGI, those plants all dropped, and then as soon as we got out of RGGI, those plants output went back up again — the gas plants that they've got. And that's what's going to happen."

Data centers are driving the load growth in Virginia. *SB 253* shifts grid upgrade and capacity costs onto them, Haner said. The bill passed both houses March 14.

The State Corporation Commission recently approved a new rate class for data centers. Judge Kelsey Bagot talked at EPSA's conference earlier in March about how the regulator is dealing with the growth in data centers. (See *EPSA Summit Held with ISO/RTOs in the Middle of the Political Debate*.)

Dominion has about 20 GW of new demand under contract and more than 40 GW in its interconnection queue, but it's unclear how much of that is "real." New data centers must wait years to connect. They have the incentive to claim a large amount of capacity so they're not left short when they get to the front of the line, Bagot said.

"You have that incentive on the data center side, at the same time that there truly is this demand that we need to build for," she added. "And so, you're trying to balance those two things. I think what we've really been working a lot with Dominion and our utilities on; is how can we shift some of that risk onto those entities that are asking for that new capacity? As opposed to having the other captive ratepayers cover the risks associated with potentially over-building for what folks in line say they need."

Uncertainty around future demand is ubiquitous. It takes four to seven years to power a greenfield facility, while data centers can go up in two, Data Center Coalition CEO Josh Levi said at EPSA's conference. Uncertainty is also present in the regulatory structure.

"The Virginia State Corporation Commission issued a ruling four months ago on large load tariffs. The General Assembly is in the process of rewriting it," Levi said. "I mean, uncertainty is very much in play right now." ■

PJM MIC Briefs

Constellation deferred on asking the Market Implementation Committee to vote on a quick-fix *proposal* to account for any downtime dual-fuel gas generators may require when switching fuels. The process allows for a *problem statement*, *issue charge* and solution to be considered concurrently.

Director of Wholesale Market Development Erik Heinle said the company is working to incorporate amendments offered by PJM to ensure the reliability value of dual-fuel units is not compromised if they switch to their alternative fuel when gas prices are high. Resources still would be required to be capable of operating for at least 16 hours on alternate fuels.

The proposal would revise the dual-fuel definition in PJM Manual 11: Energy & Ancillary Services Market Operations to reflect "limitations or restrictions resulting from fuel switching time modeling within PJM's software platforms." The current definition requires dual-fuel units offer schedules for both their primary and alternate fuels, while respecting limits stemming from "energy or environmental limitations imposed on the generating unit by applicable laws and regulations."

Erik Heinle, Constellation | © *RTO Insider*

While Heinle said PJM's amendment can be included without significantly disrupting the company's goal of having the changes implemented before the 2026/27 winter, Constellation is wary of expanding the scope to address other issues.

Manual Revisions Sought to Clarify VOM and Opportunity Costs

PJM presented *revisions* to Manual 15: Cost Development Guidelines drafted through the document's biennial review that center on clarifying the variable operating and maintenance (VOM) adder and opportunity cost calculator. Endorsement will be sought at the April 8 MIC meeting.

Language would be added to specify that the format of operating costs can be changed only at the time of submission and once every calendar year thereafter.

The opportunity cost calculator section would be expanded to state that the dispatch will be between resources' economic minimum and maximum parameters. A paragraph would be added to detail how the opportunity cost adder interacts with environmental and operational limits. ■

— Devin Leith-Yessian

PJM OC Briefs

Stakeholders Discuss SATA Proposals

PJM, Constellation and the Independent Market Monitor plan to bring competing proposals to define rules for operating battery storage as a transmission asset (SATA).

The PJM and Constellation packages would allow batteries to be brought as solutions to transmission violations, while differing on how they would be compensated. The Monitor plans to bring a proposal to explicitly prohibit storage from being defined as transmission.

The PJM proposal would define payment and cost allocation for SATA projects through the transmission enhancement credits language, with payments made through energy settlements according to injection and withdrawal. The RTO would establish when the storage can be charged or discharged and the owner would be required to maintain the state of charge and submit offer schedules. The voltage would be set by reliability studies conducted by planning staff.

Constellation underscored that SATA should be limited to being operated to resolve transmission violations and would compensate owners through cost-of-service mechanisms. The battery would be prohibited from entering the interconnection queue.

Monitor Joe Bowring said allowing SATA would be a step back toward regulated markets, arguing the logic used by SATA supporters for putting batteries in a transmission owner's rate base also could justify rate-basing combustion turbines. He pushed back on comments that the proposals from PJM and Constellation would gate the batteries to being used as transmission, unlike other RTOs, by stating that PJM cannot be compared to regions where most of the generation are cost-of-service assets.

The Monitor had sought to bring a proposal that simply stated batteries cannot be transmission assets but was told that would not be a valid package. The Monitor will bring a proposal opposing the SATA treatment of batteries as part of a transmission owner's rate base.

Monitoring Analytics President Joe Bowring | © *RTO Insider*

"It is a slippery slope towards reregulation which some transmission owners are already advocating for all types of generation," he said in an email to *RTO Insider.* "Once batteries are in a rate base, there is nothing stopping the transmission owners from arguing they should be allowed to operate as market assets. In fact, some have already made that argument."

Stakeholders responded that batteries could be used as a temporary transmission solution, as the units can be installed quickly and moved between sites in a way that generation cannot.

Bowring said there is nothing about the actual functionality of a battery requiring it to be a regulated transmission asset, rather than a market asset.

"SATA means putting batteries in a regulated transmission company's rate base with a guaranteed capital recovery and rate of return. The issue is not whether a battery or a generator can contribute to resolving issues on the grid. The issue is whether PJM will continue to rely on markets. Batteries are market assets in PJM now, and more batteries are in the generation queue and scheduled to go into service soon," Bowring said in an email. "SATA is not about how batteries are used. SATA is about who owns batteries and how they are paid."

February Operating Report

PJM saw an average hourly forecast error rate of 1.76% and slightly lower 1.71% error rate for peak hours across February, according to PJM's monthly operating report. Four days exceeded the RTO's 3% peak forecast error benchmark: Warm temperatures pushed the peak load on Feb. 3 down by 3.21% and on Feb. 4 by 4.12%. Cold temperatures led to the Feb. 17 peak being 3.06% under-forecast and 3.38% below target for Feb. 20.

There were two spin events, three shared reserve events, one conservative operations alert, two cold weather alerts, 34 shortage cases and 20 post contingency local load relief warnings issued. A dozen shortage cases Feb. 9 were attributed to higher-than-expected temperatures pushing the morning peak higher than forecast, with a similar dynamic at play behind nine cases on the morning of Feb. 2 and six on the morning and evening of Feb. 6.

A spin event was initiated at 11:49 a.m. Feb. 3 and lasted 4 minutes, 24 seconds; 1,969 MW of generation was assigned, with a 32% response rate, and 292 MW of demand response assigned, 62% of which responded. The second spin event was at 2:06 a.m. Feb 23 and lasted 6 minutes, 52 seconds. It saw 2,305 MW of generation assigned, with a 61% response rate, and 452 MW of DR assigned and 32% responding.

Security Report

PJM Senior Director of Cybersecurity Jim Gluck said the Cybersecurity and Infrastructure Security Agency is recommending utilities review their infrastructure and remove devices that have software no longer being supported by the manufacturer. The request comes in the wake of a cyberattack that disrupted communications on the Polish electric system. The infiltration was possible due to vulnerabilities in software that no longer is being patched. ■

— Devin Leith-Yessian

PJM Eyeing Tight Deadline to Eliminate De Minimis Exception, Rebill Decade of Tx Rates

By Devin Leith-Yessian

PJM *updated* stakeholders on how it plans to act on a FERC order requiring it to rework how it determines transmission rates and recalculate rates going back to June 2015.

The March 6 order rejected a settlement between several transmission owners and PJM to resolve a complaint filed by Neptune Regional Transmission System and Long Island Power Authority (LIPA), which challenged the *de minimis* exception (*EL15-18*, *et al.*)

The decision instead requires the parties to revise PJM's tariff to eliminate the exception and recalculate over a decade of rates within 90 days. The exception zeroes out the cost assignment for any zone responsible for less than 1% of the flow modeled on a transmission upgrade. The change is not applicable to costs allocated through the load-ratio share basis.

PJM Associate General Counsel Jessica Lynch said the RTO may request additional time to recalculate costs without the *de minimis* exception, as the order provides only 90 days to rerun over a decade of billing. The RTO is working to identify the baseline reliability projects affected by the order and what will be needed to recalculate their cost assignment.

Solution-based distribution factors (DFAX) are used to determine the full cost for projects less than $5 million and under 500 kV, while for higher-cost and higher-voltage projects, the calculation is split evenly between the load-ratio share basis and solution-based DFAX. Different methods are used if a project is needed to resolve stability violations.

The order denied a second prong of the Neptune/LIPA complaint, which argued PJM's practice of netting counterflows, paired with the *de minimis* exception, distorts how the benefits of a project are accounted for when setting cost allocation. The commission also established a paper hearing to explore whether solution-based DFAX should be used when a project is needed to resolve short circuit violations.

Paul Sotkiewicz, president of E-Cubed Policy Associates, asked what implications the rebilling might have on credit and default risk for PJM members.

PJM General Counsel Chris O'Hara said staff does not have a sense of the scale of the rebilling and that it would be inappropriate to speculate on default risk at this time. ■

| © RTO Insider

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse Quick Fix to Include Batteries in Planning Models

VALLEY FORGE, Pa. — The PJM Planning Committee on March 10 endorsed by acclamation a quick-fix *proposal* to include battery storage dispatch in the RTO's planning models.

The revisions to Manual 14B: PJM Region Transmission Planning Process would model storage availability by season to reflect the longer duration of winter events. Batteries are currently modeled as offline in the Regional Transmission Expansion Plan (RTEP) base cases, but they are included in generation deliverability studies.

In presenting the second read of the proposal, Lead Engineer Julia Spatafore said including storage in the RTEP analysis would increase the resources available for transmission reliability, as well as better align regional planning with state policies and the determination of network upgrades for projects in the interconnection queue.

When modeling the system for the summer, the battery availability would be set at the lesser of its effective nameplate capacity (ENC) or the ENC multiplied by the resource's duration, then dividing that value by 4 and multiplying the quotient by the fleet effective equivalent demand forced outage rate. The 4 in the equation represents the expected duration of summer events; for the winter, it would be replaced with an 8.

Director of Transmission Planning Sami Abdulsalam told *RTO Insider* that the reliability challenges presented by summer events tend to center around a single peak, while in the winter they tend to span the period between the morning and evening peaks.

He told the committee the change is a "kick start" to the RTO's effort to use batteries for reliability.

Paul Sotkiewicz, president of E-Cubed Policy Associates, argued the change is too significant to proceed under the quick-fix process, which allows an issue charge, problem statement and proposed solution to be voted on together.

PJM intends to seek endorsement from the Markets and Reliability Committee at its meeting April 22. If approved, the changes would be implemented immediately.

Transmission Expansion Advisory Committee

Supplemental Projects

UGI Utilities *presented* a $94 million project to serve a 200-MW customer seeking to come online adjacent to the Hunlock Creek substation in Pennsylvania in 2027.

The customer would initially interconnect with 100 MW to be served by upgrades to the 66-kV bus at the Mountain substation. The second half of the load would come online in 2029 following the construction of a 230/66-kV substation named Newport, which would cut into the 230-kV Susquehanna-T10 line and connect to a switching station to serve the customer with two 66-kV lines. The project is in the engineering phase with a projected in-service date of Sept. 30, 2029.

UGI canceled a $33 million project to serve a 384-MW customer near Nanticoke, Pa., because the customer canceled the project. The upgrades would have included constructing a 230-kV substation, which would have cut into two 230-kV lines between Mountain and Susquehanna.

PPL *presented* four new service requests to serve large loads in Pennsylvania, each exceeding 1 GW. The requests seek to:

- bring a 200-MW load to Washingtonville in 2028 and ramp to 1,500 MW by 2032;
- site a 100-MW load in Archbald in 2028 and ramp to 1,200 MW by 2033;
- construct a 75-MW load in Berwick in 2028 and grow to 1,500 MW by 2033; and
- develop a 60-MW load in Nescopeck in 2028 and ramp to 1,350 MW by 2032.

PPL's Robin Lafayette said direct connection costs, such as new substation equipment and lines to serve the new load, are currently fully allocated to the customer, while the costs of upgrades to existing facilities are assigned to the transmission zone in which the load is located.

Dominion Energy *presented* a $115 million project to address a 300-MW load drop violation identified in a 2029 do-no-harm analysis. The project would tear down and rebuild the 19-mile, 230-kV lines between the Gordonsville, Louisa CT, South Anna, Desper and Foxbrook Lane substations in Virginia. A parallel line would be constructed connecting Gordonsville directly to the Wesbey Drive substation, bypassing the other substations. The project is in the planning phase with a projected in-service date of March 1, 2029.

The utility also presented a $26 million project to serve a 300-MW customer in Ashland, Va. A 230-kV substation would be installed on the 230-kV Four Rivers-Hanover line, with about a half-mile of new line required.

Exelon presented a pair of $44 million *projects* to rebuild two 230-kV lines between the Plymouth Meeting and Whitpain substations in the PECO zone. The conductor on the 5.12-mile lines is about 65 years old, and the tower bolts and paint coatings are 95. The projects are in the engineering phase with one expected to be complete in July 2029 and the other in December 2029.

An additional $54 million project in the PECO zone would replace the 98-year-old Buxmont-Whitpain line. It's in the engineering phase with a projected in-service date of Dec. 31, 2028.

The utility also presented a need to address limited operational flexibility around transmission outages because of a single 500/230-kV transformer bank being in place at the Limerick substation.

Finally, Exelon *presented* a $41.5 million project to serve a new service request in the ComEd zone. The customer is expected to bring about 30 MW to the Minooka, Ill., area in June 2028, which could grow to 588 MW by 2036. The project would construct a 345-kV substation, named Wildy Road, with two 345-kV lines to the Kendall County E.C. facility. Five double-circuit lines would feed the customer. The project is in the conceptual phase with a projected in-service date of July 1, 2027. ■

— Devin Leith-Yessian

PJM Stakeholders Endorse Penalties for Pre-emergency Load Management

By Devin Leith-Yessian

The PJM Market Implementation Committee endorsed an RTO *proposal* to establish penalties for load management and price-responsive demand (PRD) resources that underperform during pre-emergency deployments.

Penalties are being considered after six pre-emergency load management events during the summer of 2025 saw a weighted average performance of 67%. (See *PJM Stakeholders Considering Load Management Performance Penalties*.)

The penalty would be set at half the rate levied against resources that don't meet their capacity obligation during a performance assessment interval (PAI), which amounts to about $1,150/MWh based on capacity prices for the 2027/28 delivery year. The formula mirrors the calculation for PAI penalties but doubles the number of expected deployment hours each year to 60. They would count toward the annual stop-loss for Capacity Performance penalties.

PJM's Pete Langbein said the lower rate reflects that pre-emergency deployments are less severe than PAIs.

Penalty revenues would be awarded to overperforming curtailment service providers (CSPs) if the fleet-wide response meets or exceeds the amount committed. If demand-side resources under-respond, a pro-rated share of the revenues would be allocated to load-serving entities.

The PJM proposal received 86.1% support, while an alternative offered by Voltus received 39.3% and two packages from the Independent Market Monitor received 25.7% and 14.4%.

Voltus

Voltus *adopted* a similar formula to PJM, but it added a 50% derate to account for the diminished reliability risk associated with pre-emergency events and increased the number of expected deployment hours to 90. The resulting penalty would have been 16.7% of the PAI rate, or about $383/MWh.

Pete Langbein, PJM | © *RTO Insider*

Revenues would have been allocated to overperforming demand-side resources at 120% of the penalty rate, pro-rated for the amount they exceeded their assignment. The 20% adder is intended to create an incentive to overperform without allowing a windfall if the bulk of the response is from a small number of CSPs. Any excess would be provided to LSEs.

If the number of pre-emergency load management hours exceeded expectations, the package would have increased the overperformance bonus to 150% to counteract potential fatigue. The possibility of load management deployments becoming more regular as reserve margins tighten has become a frequent subject for stakeholders concerned it could drive away participation.

Monitor

The Monitor's *proposals* would have required demand-side resources to curtail according to PJM instructions. Rather than a set penalty rate, it would have withheld daily capacity payments from the latter of the start of the delivery year or their last successful performance or test, spanning to the next successful performance or test. The amount withheld would have been based on resources' shortfall and the revenues would be entirely allocated to loads rather than to other demand-side resources.

"Load pays for these resources, and load should receive the penalty revenue when the resource fails to perform," Monitor Joe Bowring said in an email to *RTO Insider*.

The Monitor's alternative proposal would have measured performance for each registration and prevented CSPs from netting performance across sites.

David Mabry, representing the PJM Industrial Customer Coalition, argued the Monitor was misconstruing what load management and PRD resources are expected to provide. Rather than provide a set reduction in load, they must maintain their load below a pre-defined level when dispatched.

Bowring said the Monitor's proposals would prevent resources from being paid for being capable of curtailing when they do not do so when requested.

Pamela Wildstein, a market analyst with the Monitor, said the requirement is to reduce demand when dispatched and cited the tariff provision that states the requirement.

The alternative package was introduced during the meeting to define the performance obligations of demand-side resources with the intention of clarifying what the penalties are for. Bowring said there are several key weaknesses in how PJM defines the obligations of demand resources as capacity resources. Those include "not actually requiring a reduction in load when called to respond by PJM; not measuring the current load and therefore not accurately measuring reductions in load by the resources; simply ignoring actual increases in load by demand resources when called to respond; and allowing aggregation across hours and resources rather than calculating penalties by hour and by individual registration." ■

BPA's Exit from WEIM Necessary for Markets+ Preparation, Staff Says

By Henrik Nilsson

The Bonneville Power Administration's planned departure from the Western Energy Imbalance Market has prompted questions about how the agency will handle the yearlong period before it joins SPP's Markets+.

The agency plans to exit the EIM by Oct. 1, 2027, and trade in bilateral markets until Oct. 1, 2028, when it expects to join Markets+, BPA staff said during a *day-ahead market participation workshop* March 12.

BPA staff don't expect any hiccups related to liquidity or finding trading partners in a bilateral market, saying, "We're bidding in with reserves that we're already holding."

Libby Kirby, BPA's Markets+ program manager, said most of the agency's trades are already bilateral.

"We submit non-regulating balancing reserves as the minimum that we put in the market," Kirby said. "We will no longer do that. We will return to balancing within the [balancing area]. … We still have … the same methodology. We hold the same amount of balancing reserves."

Still, meeting participants voiced concern.

"An entire year to be out of the EIM just seems like a really long time, considering that you're already in the EIM now," Henry Tilghman, a consultant for the Northwest & Intermountain Power Producers Coalition, said during the meeting. "It seems like it'd be just as much work for operations people to manage in the bilateral market as the EIM."


BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

Elsa Chang, BPA's EIM program manager, said the agency will commit resources beginning in January 2028 to start training, system configuration testing and the other necessary steps to join Markets+.

The full year is needed for the "time to do training, to do testing," Chang said. "We would have to go straight into these SPP activities without much prep time."

Dan Williams, principal adviser for Western markets at The Energy Authority, supported the plan. By setting a firm timeline, BPA is allowing other entities in the region to prepare for bilateral trading liquidity instead of dealing with uncertainty, he argued. He said he hopes the exit from the EIM will prompt discussions on the seams between Markets+ and CAISO's Extended Day-Ahead Market, which is to launch May 1, 2026. (See *BPA Outlines Next Steps in Markets+ Implementation*.)

"There's no reason that by that point in 2027, we can't have bilateral markets working better with EDAM that will allow BPA to have markets to buy and sell into and maintain market liquidity across the region, even after exiting the EIM," Williams contended.

But Chris Roden, director of energy resources at Clatskanie People's Utility District, asked for more transparency on what the EIM exit will mean, saying the transition feels like a "Jesus-takes-the wheel moment."

"We have a number of subsequent processes that we run based on that market participation," Roden said. He added that settlements and rates "have become really contingent upon EIM participation." ■

BPA Releases Draft Decision Solidifying Markets+ Choice

Says Move Positions it to Implement 2025 Decision to Participate in SPP's Market

By Henrik Nilsson

The Bonneville Power Administration released its draft proposed decision to join SPP's Markets+, noting that a year after the agency issued its record of decision in favor of the market, preparations have advanced to a point where BPA can "move forward with implementation and propose joining Markets+ in October 2028."

The draft decision differs from the agency's day-ahead market policy and record of decision that it issued in 2025. Those were "a direction toward participation in Markets+" when the market was still in a "conceptual stage," BPA staff said during a March 12 workshop discussing the decision. (See *BPA Chooses Markets+ over EDAM*.)

"We are pleased to share that we have advanced our planning for systems, processes and market implementation because of the rapid progress in Markets+ development," BPA Administrator John Hairston wrote in a *letter announcing the draft decision*. "This progress in market development has allowed the agency to advance implementation planning efforts and further evaluate readiness requirements. We are now positioned to move forward with implementation and propose joining Markets+ in October 2028."

Hairston touted Markets+'s day-ahead and real-time capabilities, writing the market would "ensure a reliable, affordable and abundant energy supply for consumers in the Northwest."

The decision will allow BPA to continue preparing for market entry and work with customers on day-ahead market implementation, according to the letter.

Hairston's letter briefly notes that in the lead-up to the earlier ROD, the agency found it would reap greater benefits in Markets+ than in CAISO's Extended Day-Ahead Market.

The agency is not "revisiting" the issue. Rather, BPA seeks comment only on the March 12 draft decision, Hairston wrote.

Following the release of the ROD, BPA began reviewing its ability to satisfy Markets+ obligations. The agency joins not only as a market participant but also as a balancing authority, transmission operator and transmission service provider, and must therefore "have the capability to perform numerous tasks," Hairston noted.

"Bonneville will continue to engage in proactive planning for both agency and customer Markets+ participation activities throughout this process," according to the letter. "Bonneville's customer and stakeholder engagement will be ongoing, including through its day-ahead market workshop series, tariff proceedings and rate case processes."

The first wave of participants will join Markets+ on Oct. 1, 2027: Arizona Public Service, Salt River Project, Tucson Electric Power, Powerex and Xcel Colorado. BPA expects to join a year later alongside Chelan County Public Utility District, Grant County Public Utility District, Puget Sound Energy and Tacoma Power.

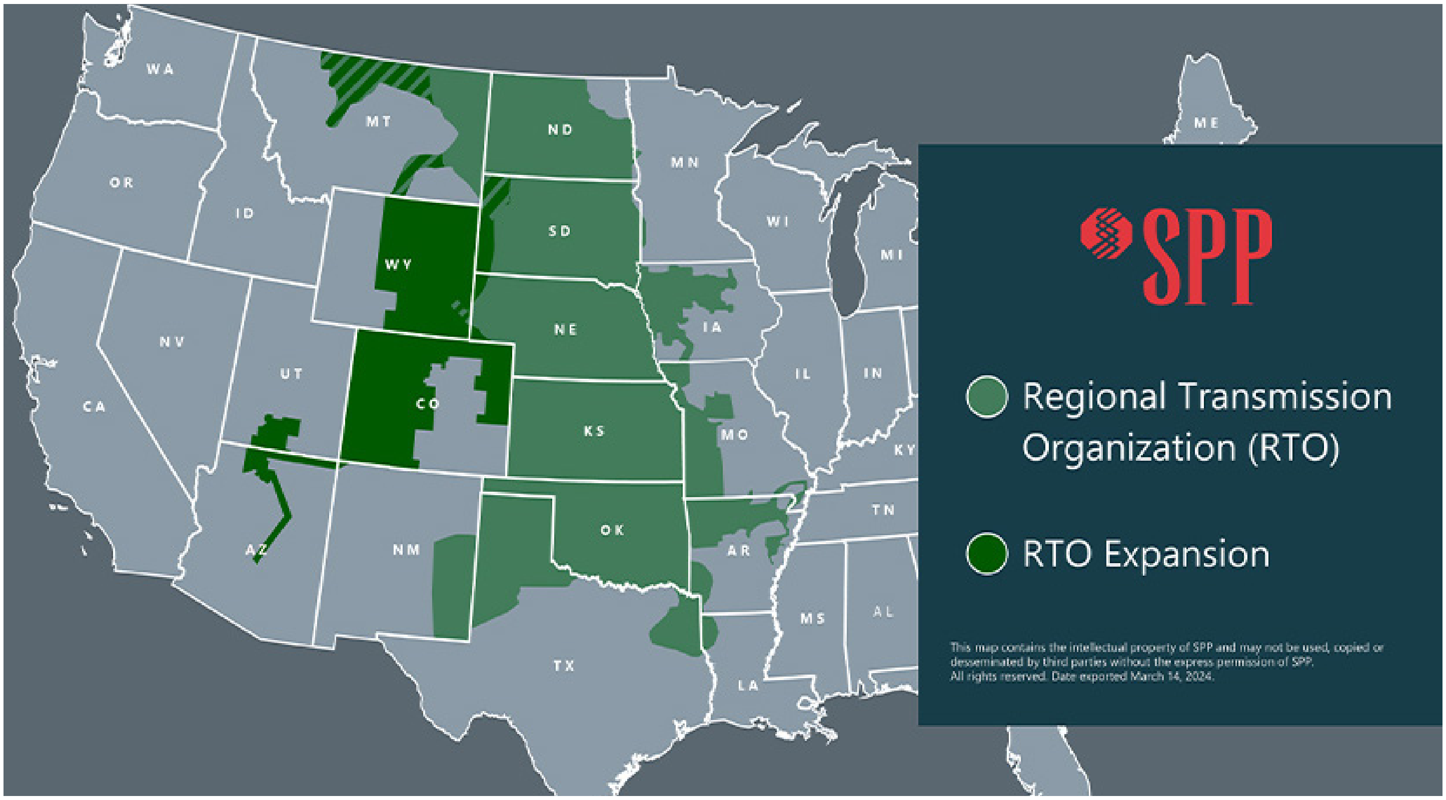
Stakeholders have until April 3 to comment on the draft decision. ■

Why This Matters

BPA says the proposed decision will allow it to continue preparing for its participation in Markets+, which is expected to begin in October 2028.

BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

SPP RTO Expansion Members Affirm April 1 Go-live



SPP's RTO footprints come April 1 | *SPP*

By Tom Kleckner

Future participants in SPP's RTO expansion into the Western Interconnection have affirmed their support to meet the April 1 go-live deadline with a unanimous vote of support.

SPP said in a March 12 news release that the decision to proceed as planned with the *Western RTO expansion* is a "strong signal of confidence" as the grid operator and its members complete their final system tests.

"April 1 will be a milestone day for SPP," CEO Lanny Nickell said in a *statement*, noting the grid operator will be the first RTO to bridge the Eastern and Western grids.

The expansion marks the culmination of more than a decade of outreach and collaboration with Western entities. Those efforts have included the failed Mountain West Transmission Group, but also the Western Energy Imbalance Service market and Markets+, the latter of which is expected to be deployed in October 2027. (See *Monroe's Western Outreach Pays Dividends for SPP*.)

The expansion will occur overnight March 31-April 1, when SPP will begin administering the regional transmission grid under its tariff for the following organizations:

- Basin Electric Power Cooperative
- Colorado Springs Utilities
- Deseret Power Electric Cooperative
- Municipal Energy Agency of Nebraska (MEAN)
- Platte River Power Authority
- Tri-State Generation and Transmission Association
- Western Area Power Administration (WAPA) regions: Upper Great Plains (UGP)-West, Colorado River Storage Project and Rocky Mountain.

"Joining the SPP RTO expansion marks the culmination of nearly a decade of dedicated work by our employees and a major milestone for our owner communities as we advance toward a non-carbon energy future," Platte River CEO Jason Frisbie said. "This integration will provide broader access to renewable energy resources and allow us to realize the cost efficiencies that come with participating in a fully integrated energy market."

SPP said several other load-serving and embedded entities that are part of WAPA's Colorado-Missouri balancing authority also will become part of the SPP RTO on April 1. Those listed above were the signatories to RTOE's commitment agreement and would have been financially accountable for sunk costs if the expansion effort had been terminated before go-live.

Basin, MEAN, Tri-State and WAPA's UGP-East region already are RTO members of SPP, as is United Power. The Colorado utility was the *first Western distribution utility* to join the SPP RTO in 2022.

The expansion began in 2020 when several utilities decided to explore RTO membership. A *Brattle Group study* found the move would be mutually beneficial and save $49 million annually.

SPP says its wholesale electricity market, resource adequacy program and other regionalized services can help Western members reach renewable energy goals; strengthen system reliability; and use new opportunities to buy, sell and trade power. ■

SPP's Consolidated Planning Process a 'Bold Step,' FERC Says

Commission Urges Other RTOs, ISOs to Explore Similar Reforms

By Tom Kleckner

FERC conditionally approved SPP's streamlined generator interconnection and long-term planning processes in what the commission said is a "bold step" in addressing the needs of the electric system.

The commission found in its March 13 order that SPP's Consolidated Planning Process (CPP) complies with FERC Order 1000's regional transmission planning and cost-allocation requirements and that its generator interconnection (GI) procedures satisfy the independent entity variation standard for deviations from Order 2003 (*ER26-414*).

However, it directed the grid operator to submit a compliance filing by April 14 addressing several errors outlined in a December 2025 *deficiency letter*. FERC also ordered SPP to clarify that some interconnection customers may be directly assigned network upgrade costs for upgrades with a nominal operating voltage of 100 kV or below.

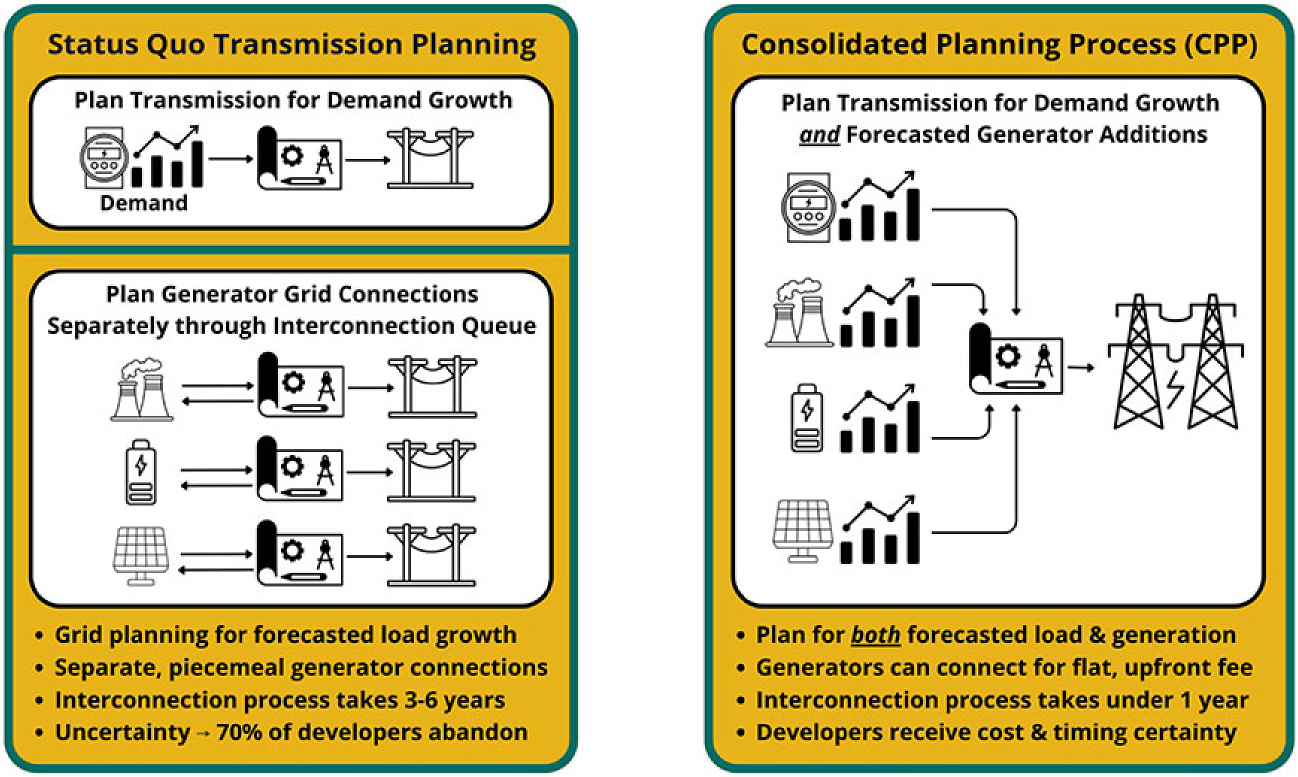
The CPP will replace the grid operator's separate interconnection requests and annual Integrated Transmission Plan (ITP) with an "innovative approach" to regional planning that forecasts overall needs and takes all grid requirements into account. SPP said it will provide more certainty to investors in planning their budgets, and a revamped funding structure to address the region's historic load growth and challenges interconnecting generation and load in a timely manner.

"FERC's approval of SPP's CPP filing marks a defining moment, further demonstrating the value of a regional transmission organization," Casey Cathey, SPP's vice president of engineering, said in a *statement*. "The CPP unlocks the ability to plan and build the grid at a scale and speed the future demands. It's a powerful step toward a more reliable, resilient and valuable system that can meet unprecedented load growth and connect the next generation of resources."

Why This Matters

SPP's Consolidated Planning Process replaces the current separate generator interconnection requests and annual Integrated Transmission Plan with an "innovative approach" to regional planning that forecasts overall needs and takes all grid requirements into account.

Commissioner Judy Chang concurred with SPP's "bold step" and encouraged other grid operators to "explore comparable reforms." She said the RTO's proposal addresses upgrade cost uncertainties, the "core issue that has been delaying the interconnection of new generation."



SPP's Consolidated Planning Process | *FERC*

"Facing rapid load growth and the need for new resources, we must meet this moment, and proposals like SPP's put us on the path to do so," Chang wrote.

'At the Forefront'

Commissioner David Rosner issued a *separate concurrence* with the order, calling the CPP a "major step forward" in improving speed and efficiency in the GI and planning processes that "promises to deliver the electrons our country so badly needs."

"Faced with electric demand growth at levels not seen in 25 years, SPP and its stakeholders have risen to the occasion with one of the most innovative, common-sense proposals presented to the commission since the inception of open-access transmission service," he said. "This proposal will get transmission built smarter and connect new generation faster, helping to make energy more reliable and affordable in the SPP region."

Rosner noted the CPP won unanimous support from both SPP's member states and stakeholders. In an emailed statement to *RTO Insider*, the Sierra Club and Natural Resources Defense Council said the "historic level of consensus" reached during the stakeholder process sets a "high standard for future SPP policy initiatives."

"Today's decision places SPP at the forefront of ongoing efforts across the country to address over-burdened resource interconnection queues that have held back the clean energy transition our country so desperately needs for over a decade," Sierra Club Senior Attorney Greg Wannier said. "CPP is a game-changer, and we encourage other grid operators across the country to take note as this process moves forward."

"By breaking down siloed processes, CPP will cut years of wait time to get clean energy on to the power grid and ensure transmission planning drives optimal, long-term, high-value transmission projects," said Annie Minondo, of NRDC's Sustainable FERC Project.

Under the proposed CPP framework, SPP will conduct a long-term transmission assessment over a 20-year horizon, with a focus on both extra-high-voltage (300-kV and above) and high-voltage (above 100-kV and below 300-kV) facilities, and a 10-year assessment in the planning cycle's first year. The grid operator will also conduct annual CPP-10 assessments in the second and third years of each planning cycle.

The CPP will combine the first two phases of the IC study process, which used to take at least a year, into a single 180-day study. It establishes a regional, long-term generation expansion plan and a set of pre-planned locations where transmission capacity will be available to accommodate new requests, thereby providing interconnection customers with clear signals regarding which locations are optimal from a transmission capacity perspective.

SPP will open its first CPP window in April and publish the first generalized rate for interconnection development-contribution (GRID-C) in fall 2026. The GRID-C is a new, standardized rate for system upgrades that will give developers better upfront certainty before they commit to interconnection. Transitional work will bridge the gap between the current ITP/GI and CPP frameworks. ■

Duke Files Settlements in Carolinas on Proposed Utility Combination

By James Downing

Duke Energy has entered a pair of settlements in North and South Carolina on its proposal to combine Duke Energy Carolinas and Duke Energy Progress, which still needs approval from both states' regulators.

Duke said combining its Carolina subsidies would help it meet the states' growing energy needs at a lower cost. (See *Duke Energy Says Combining Carolina Utilities Would Save Billions*.)

The deal before the North Carolina Utilities Commission was filed in late February and signed by North Carolina Public Staff, the North Carolina Attorney General's Office, Google, Nucor, Walmart and others.

"We're pleased that public staff and the attorney general's office agree our customers will see significant future cost savings and other meaningful benefits from combining our two utilities," Duke Energy North Carolina President Kendal Bowman said in a statement March 10. "It reduces customer costs, simplifies operations, promotes regulatory efficiencies and supports economic growth across the Carolinas."

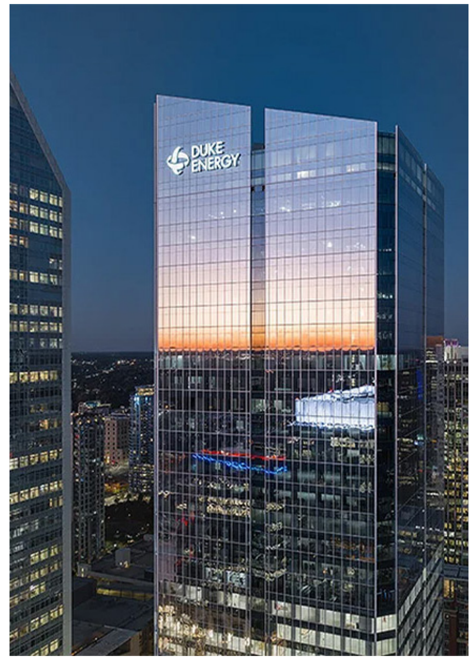
Why This Matters

The filings include commitments from the utility to save hundreds of millions of dollars through lower production costs from more efficient operations and lower capital costs from more efficient planning.

The *deal* pending before the Public Service Commission of South Carolina was filed March 6 and endorsed by the state's Office of Regulatory Staff, Nucor, Walmart, Vote Solar, the Sierra Club and others.

"Our engagement has been laser-focused on consumer protections and affordability for South Carolina families and small businesses, and one of the best ways to do that is by investing in alternatives to building new costly and polluting resources," Sierra Club's Paul Black said in a statement. "Duke's regulators at the Public Service Commission must turn their attention to establishing strong consumer protections that require tech companies, not families, to pay for all of the energy and infrastructure costs for new data centers, and the Sierra Club has laid the groundwork to make that happen."

Duke Energy Carolinas owns 20.8 GW of generation and serves 2.9 million customers across a 24,000-square-mile territory, while Duke Energy Progress owns 13.8 GW to supply 1.8 million customers across a 28,000-square-mile territory.



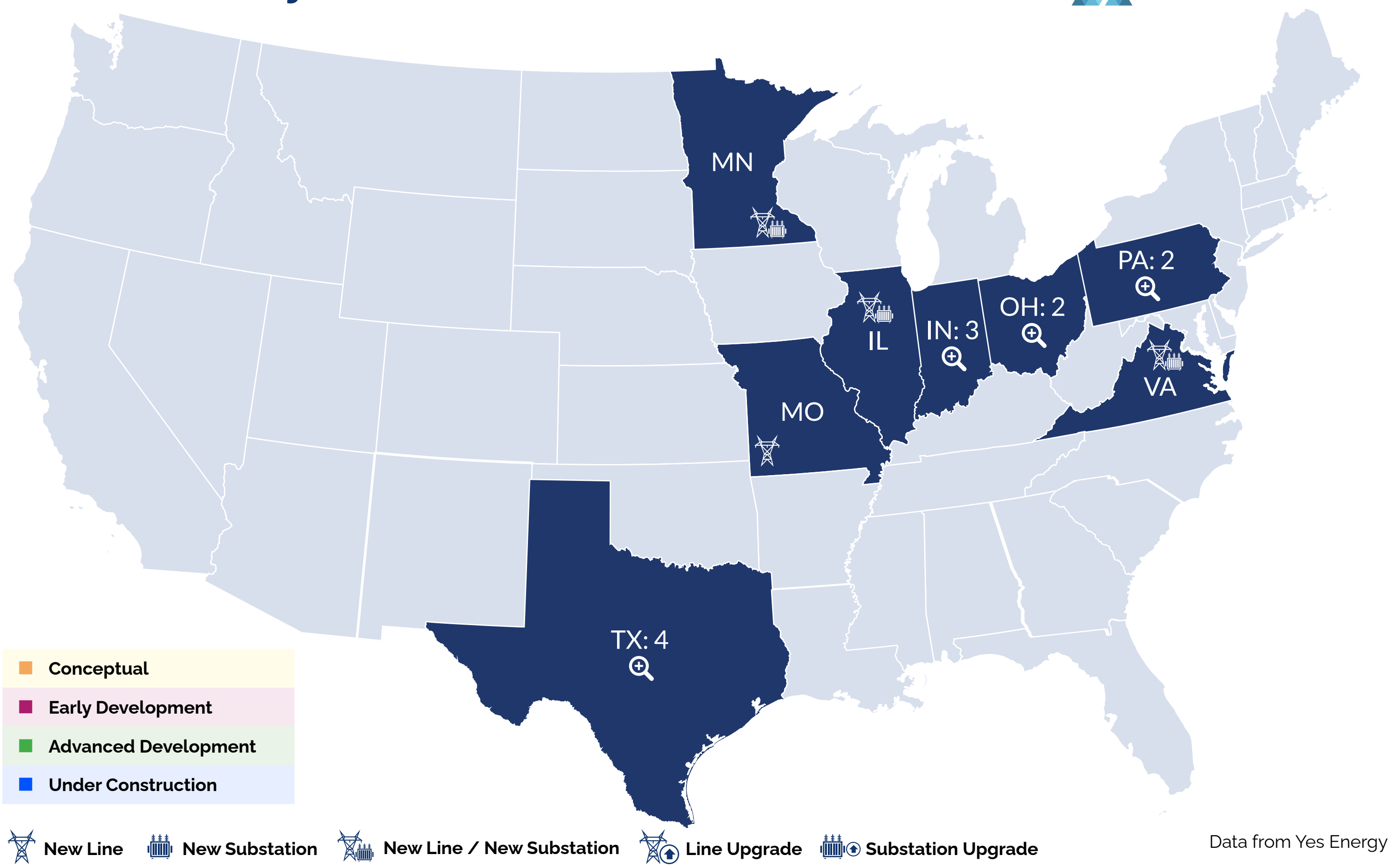
| Duke Energy

The filings with both states include commitments from the utility to save hundreds of millions of dollars through lower production costs from more efficient operations and lower capital costs from more efficient planning.

The proposal already has been approved by FERC. Assuming the two states approve the settlements, Duke expects to combine the subsidiaries effective Jan. 1, 2027. (See *FERC Approves Duke Proposal to Combine Carolinas Subsidiaries*.) ■

New T&D Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

	Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	State 1 / 2
	Princeton - Lima New Line	Ameren	Ameren Illinois	138	2029	IL
	Teays River Wind Network Upgrade	American Electric Power	Indiana Michigan Power	345	2030	IN
	Bluestem Solar Farm Network Upgrade	American Electric Power	Indiana Michigan Power	345	2029	IN
	Hobart Substation Upgrade	NiSource	NIPSCO	345	2028	IN
	Kellogg New Substation and Line	Dairyland Power Cooperative	Dairyland Power Cooperative	161	2028	MN
	New Unnamed Line (Diamond - MO/OH state line)	Algonquin Power & Utilities Corp.	Liberty Utilities-Empire District	345	2026	MO
	North Clayben Substation Upgrade	FirstEnergy Corp.	ATSI	138	2029	OH
	Mansfield Airport New Substation	FirstEnergy Corp.	ATSI	138	2028	OH
	Bredinville - McCalmont Line Tap	FirstEnergy Corp.	Allegheny Energy	138	2027	PA
	Lewistown - Logan New Tap (Molly Ring)	FirstEnergy Corp.	Pennsylvania Electric (Penelec)	46	2027	PA
	Waco Solar II Network Upgrade	NextEra Energy, Inc.	Lone Star Transmission, LLC	345	2028	TX
	Varadero Solar Network Upgrades (Liberty)	NextEra Energy, Inc.	Lone Star Transmission, LLC	345	2028	TX
	Tornillo - Tuskegee New Line and Substations	Infrastructure Investments Fund	El Paso Electric	345	2031	TX
	Morris - Marina New Line	American Electric Power	Texas Central Company	138	2026	TX
	Wild Rose Solar Network Upgrades	American Electric Power	Appalachian Power	138	2030	VA

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

Company Briefs

Valley Link Transmission Group Plans 765-kV Line in Virginia

Valley Link Transmission, a partnership between Dominion Energy, FirstEnergy Transmission and Transource Energy, is planning a 115-mile, 765-kV line in Virginia.

The final route of the $1 billion project is yet to be determined, but a map of possibilities shows it could cross nine counties: Appomattox, Buckingham, Campbell, Culpeper, Fluvanna, Goochland, Louisa, Orange and Spotsylvania. PJM has already approved the project.

Officials anticipate the State Corporation Commission will take a year to evaluate the project and its route with, a decision coming around September 2027. The line is expected to be completed in 2029.

More: *Cardinal News*; *WRIC*

Google to Invest $1B in North Carolina Data Center Expansion

Google will invest more than $1 billion over two years to grow existing data center infrastructure in Lenoir, N.C.

Opened in 2007, the Lenoir data center supports services such as Google Maps, YouTube, search services and more, according to a release.

Google also is considering building what would be the largest data center in Nebraska with a privately built utility-scale natural gas plant.

More: *Asheville Citizen Times*; *Flatwater Free Press*

Standard Solar Buys 48-MW Portfolio in New Mexico

U.S. solar developer and asset owner Standard Solar has acquired a 48.4-MW community solar portfolio in New Mexico.

The company will take over eight projects, some of which are already operational. Others are slated to come online in 2026.

The projects originally were developed by Pluma Construction.

More: *Renewables Now*

Federal Briefs

BloombergNEF: Global Wind Power Installations Hit All-time High

Global wind capacity additions hit an all-time high in 2025, marking a third consecutive year of record installations, according to BloombergNEF's "Global Wind Turbine Market Shares 2025" report.

Project developers brought 169 GW of wind online in 2025, 38% more than in 2024. About 161 GW (95%) of the additions were onshore, while 8 GW were installed offshore.

China's onshore wind sector accounted for most of the growth, becoming the first market to add more than 100 GW in a single year.

More: *BloombergNEF*

Trump Mulls Jones Act Waiver

The Trump administration is considering waiving the Jones Act for 30 days to ensure energy and agricultural shipments can move freely between U.S. ports, Press Secretary Karoline Leavitt said.

Under the Jones Act, goods shipped between U.S. ports must be carried on U.S.-built, U.S.-flagged and mostly U.S.-owned vessels. The requirement sharply limits the number of tankers available for domestic shipments but is supported by maritime labor unions. The move would be aimed at combating spiking fuel prices and other disruptions since the start of the U.S.-Israeli war on Iran.

Seven maritime labor unions have publicly rejected the idea.

More: *Reuters*

Trump Memo: TVA Employee Comp Should be $500K at Most

President Donald Trump recently issued a memo calling for the TVA board to limit compensation for all employees to $500,000.

The move would affect not just new CEO Don Moul, who is set to be paid $6 million/year, but about 230 other employees. Former board members said TVA would likely struggle to attract a qualified CEO for only $500,000.

The CEO role was created in 2006 after Congress amended the TVA Act. The move also changed the three-person executive board into a nine-person part-time corporate board.

More: *Chattanooga Times Free Press*

National/Federal news from our other channels

NERC RSTC Prepares for New Role in Standards Process — ERO Insider

SERC Speakers Warn of Rapidly Evolving Security Threats — ERO Insider

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

State Briefs

ALABAMA

Senate Advances Bill to Expand PSC

The Senate passed a bill that would expand the Public Service Commission from three members to seven, who would represent areas of the state rather than serving in an at-large capacity.

According to the bill, the governor would appoint four commissioners by July 15. Two commissioners would serve two-year terms while two would serve four-year terms. The governor would be required to select appointees from a list of three names submitted by the lieutenant governor, house speaker and senate pro tempore for each position. Commissioners elected after June 1 would serve six-year terms.

The bill does not change the way utilities are regulated or address profit but would freeze base rates through June 2029.

More: *WBRC*

KENTUCKY

Senate Passes Bill Exempting EPIC from Open Records Law

The Senate voted 29-6 to approve a bill that would exempt the taxpayer-funded Energy Planning and Inventory Commission (EPIC) from the state's Open Records Act.

The bill would exempt "information, records, data, files, documents or correspondence" created by EPIC. The legislature created EPIC in 2024 to review utilities' plans to retire fossil fuel-fired power plants, along with analyzing supply, demand and infrastructure.

The bill would also remove appointments made by Gov. Andy Beshear to an executive committee within EPIC and give appointment power to Attorney General Russell Coleman.

More: *Kentucky Lantern*

MAINE

Harrington Adopts Utility-scale Solar Moratorium

The town of Harrington voted to enact a moratorium on utility-scale solar farms.

The Solar Energy Ordinance authorizes personal ground-mounted systems and personal and commercial roof-mounted installations but does not authorize power to be distributed to the grid for profit. The commercial provision applies only to businesses that install systems to power their own operations.

More: *The Maine Monitor*

House Passes Bill Requiring PUC to Consider Affordability

The House passed a bill that would require the Public Utilities Commission to consider the impact of affordability and publicize data from utilities.

The amended bill directs the PUC to develop an affordability metric to assess the impact of bills on customers' overall energy burden, which would be submitted to a legislative committee by Jan. 15, 2027. The commission also would be required to publicize data from utilities related to credit and collection activities, and to conduct a review of rates, during which it would consider options to contain costs in delivery rates, reduce transmission and distribution bill volatility, and increase bill transparency.

The bill now heads to Gov. Janet Mills.

More: *Maine Morning Star*

MICHIGAN

Apex Clean Energy Ditches Plans for Wind Farm

Apex Clean Energy announced it is abandoning plans to build a wind farm on 50,000 acres in the western part of the state.

According to reports, Apex was able to sign leases with about 500 property owners, which fell short of its goal by about 20,000 acres.

More: *Michigan Public Radio*

MISSISSIPPI

DEQ Approves xAI Permit

The Department of Environmental Quality unanimously approved a plan by xAI to build a 41-turbine natural gas power plant.

The generators would power xAI's data centers in Memphis, Tenn.

The DEQ's decision comes three weeks after it held a town hall to invite feedback on xAI's application. Dozens of residents and advocates — both from Mississippi and Tennessee — spoke out against the permit. No one spoke in favor of the facility.

More: *Mississippi Today*; *CNBC*

NEVADA

NV Energy Asks PUC to Delay Peak Demand Charge Start Date

NV Energy asked the Public Utilities Commission to push back implementation of its peak demand charge until Oct. 1.

The legality of the demand charge is being challenged by the Attorney General's Bureau of Consumer Protection. It was scheduled to go into effect April 1. Under state law, utilities can ask to change the implementation of new charges up to 10 days before they are scheduled to go into effect.

More: *Nevada Current*

NORTH DAKOTA

Judge Voids Summit's CO_2 Storage Permit

South Central Judicial District Judge Jackson Lofgren revoked Summit Carbon Solutions' permits for underground carbon dioxide storage, saying parts of the state law under which they were issued are unconstitutional.

The decision is the second time a judge has reached the conclusion that the 2009 state law violates the state's constitution. The law authorizes regulators to permit the storage of carbon dioxide beneath the property of nonconsenting landowners.

A Summit spokesperson said the company is reviewing the decision and evaluating next steps.

More: *North Dakota Monitor*