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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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PJM

PJM Board of Managers Selects CIFP Proposal to Address Large Load Growth

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PJM staff will conduct an analysis in the first half of 2026, followed by a stakeholder process to create a set of recommendations for the board to consider.

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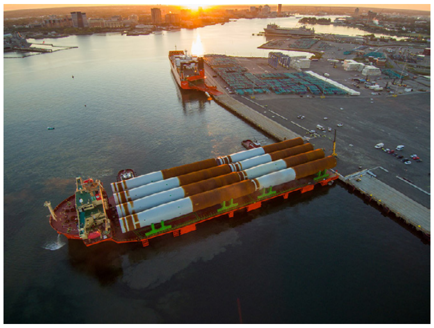
FERC/FEDERAL



Dominion Energy

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In this week's issue

Much Ado in PJM, but There is No Crisis

By Steve Huntoon


Steve Huntoon

Jan. 16 saw the release of a joint statement by the Trump administration and all 13 PJM governors proposing a host of *new initiatives*, with attendant press releases, etc. Hours later, the PJM board released its own *decisional letter* with directions to PJM staff. (See *White House and PJM Governors Call for Backstop Capacity Auction* and *PJM Board of Managers Selects CIFP Proposal to Address Large Load Growth*.)

The principal driver for all this is that in the most recent capacity auction, for the delivery year 2027/28, PJM cleared 145,777 MW, which was 6,517 MW less than the "*reliability requirement*" of 152,294 MW. This comes at a time of high capacity prices. The combination of cleared capacity shortfall and high capacity prices is seen as a crisis requiring extraordinary measures. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

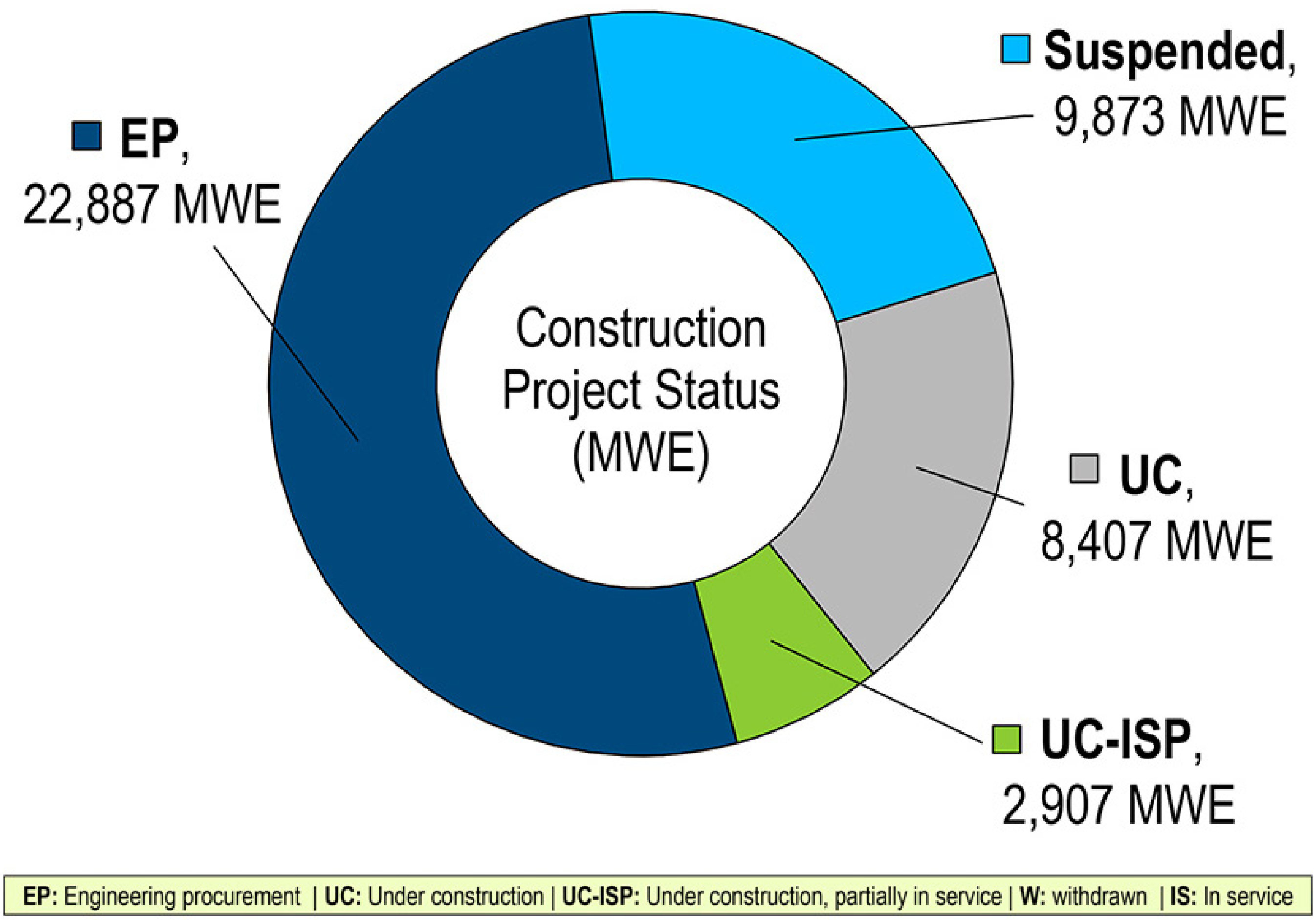
There is no crisis. Industry expert Matt Estes *explains* in plain language what the shortfall really entails:

"First of all, people who live in the PJM region don't need to rush out to buy home generators. Although PJM was unable to acquire all of the capacity that it said it needed to ensure reliability, this does not mean PJM will inevitably be subjected to blackouts. PJM was able to acquire significantly more capacity than it anticipates will be necessary to serve its maximum demand for the year. Instead, the shortfall affects PJM's reserve margin, which is the amount of capacity PJM acquires above its projected peak demand. The reserve margin allows PJM to supply the peak demand even if some capacity is unavailable due to problems with equipment or for needed maintenance, and/or if demand is higher than expected.

Why This Matters

Newly available generation can be procured for the 2027/28 delivery year in the incremental auction to be held in February 2027, so the shortfall did not portend an emergency, the shortfall was overstated, and there is an abundance of potential new supply.

"PJM wanted to acquire enough capacity to achieve a 20% reserve margin. Although this did not happen, PJM still acquired enough capacity to have a 14.8% reserve margin. This is a healthy



PJM's current construction project status | *PJM* margin, and close to PJM's target reserve margin in many previous auctions. I know in the past PJM has been criticized as using overly conservative assumptions for determining its needed reserve margin. And even if a 20% margin is needed to meet its one-event-in-10 year reliability standard, there is only a 10% chance that once in 10 years circumstances will occur in the year in which PJM failed to acquire enough capacity to achieve a 20% reserve margin."

And even if a shortage event did happen, it could be managed by rolling blackouts of short duration for a small percentage of retail customers in PJM. (This is, however, a useful reminder to utilities that they need to make sure their outage management tools, such as customer communications, are up to snuff.)

The PJM board has identified an additional option of requiring "certain large loads, including data centers, to move to their backup generators, or curtail their demand, for a limited number of hours during the year to prevent a larger scale outage for residential and other consumers." There was 13,000 MW of projected data center demand in the load forecast for the 2027/28 *auction* (along with 4,000 MW of existing data center demand).

Now let's look at why the shortfall occurred. According to PJM, there was a 5,249.9-MW increase in forecast load, mostly due to additional large loads (i.e., data centers).

It now appears the forecast demand increase was overstated. PJM's most recent load forecast shows a 3,735-MW reduction in *the forecast* for the 2027/28 delivery year "due to updates to the electric vehicle and economic forecasts as well as improved vetting of requested adjustments for data centers and large loads."

In other implications for the future, there is a large amount of new generation in *various stages of development*, some portion of which will go into service and offer in future auctions. The current state of resource planning is described *here*.

Newly available generation can be procured for the 2027/28 delivery year in the incremental *auction* to be held in February 2027.

In summary, the shortfall did not portend an emergency, the shortfall was overstated, and there is an abundance of potential new supply.

With this knowledge, let's consider the Trump-governors proposal for a "Reliability Backstop Auction to procure new capacity resources commencing no later than September 2026." Where is this new capacity coming from so quickly? In *the last auction*, there was only 810 MW of eligible supply available that did not clear, due to the temporary price cap.

And, in complete contradiction to acquiring even this small amount of new capacity, the proposal also calls for extending the temporary price cap.

And how would this backstop auction differ from the next regular auction coming up in July? Would the price cap not apply to the backstop auction? My head hurts.

And what about all the new generating plants in various stages of development? Will they be able to offer into the backstop auction when they otherwise would offer into the regular auctions? If so, the available future supply for existing PJM customers would be reduced, creating upward price pressure in the regular auctions. And if not, where will supply for the backstop auction come from? Brand new generating projects taking years to go from conception to in-service? My head hurts.

And who are the buyer(s) of the reported $15 billion in generation? Some reports suggest it's the data centers themselves, while others suggest it's PJM, which would pass the costs through to load-serving entities with the states directing how the LSEs allocate the costs. My head hurts.

OK, I'll stop here.

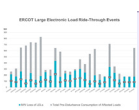
P.S. Except to flag this repeated claim in the Trump administration's so-called "*fact sheet*": "PJM forced nearly 17 GW of reliable baseload power generation offline during the Biden years." This is completely false.

As everyone connected with PJM knows, PJM hasn't forced a single gigawatt of baseload generation offline. PJM doesn't have the power to do that, even if it wanted to. And it's exhibited no want to do so. Instead, PJM for years has expressed reliability concerns about the retirement of baseload power plants, such as *here* and *here*. ■

OK, this time I'll really stop.

Columnist Steve Huntoon, a former president of the Energy Bar Association, practiced energy law for more than 30 years.

National/Federal news from our other channels



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ISO-NE's Proposed Capacity Market Reform Likely to Boost Reliability While Resulting in Higher Prices

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

Over the past year, "capacity" — the assurance that electricity will be there when one flips the switch — increasingly has dominated the electricity conversation. PJM has been the epicenter of that conversation.

That market has seen its previous three *capacity auction* revenues skyrocket by tens of billions of dollars, driven largely by unexpected and rapid load growth from data centers as well as the adoption of a more rigorous method for accrediting the capacity of various resources.

Seeking to avoid a similar problem, ISO-NE is reforming its approach to acquiring sufficient capacity, submitting *a proposal* to FERC on Dec. 30. The filing is ISO-NE's biggest change in this area since such markets first were established 18 years ago, evolving from its traditional three-year lead time model to a "prompt" approach, beginning in 2028.

Closing the 3-Year Gap

With the new proposal, ISO-NE will shake things up considerably. Citing growing uncertainty in *load forecasting* — a result of hard-to-predict end uses such as "the construction of data centers, and changes in public policy that could impact the pace of electrification," as well as increasingly volatile weather and the variability of renewables output — the grid operator proposes to reduce the three-year lead time to only a single month.

The three-year schedule originally was intended to provide economic signals that provided sufficient time for developers to build new resources. But given the evolution of markets and technologies, that logic has unraveled.

When I oversaw Constellation Energy's demand response group back when the formal DR markets were created around 2005, we found that prices whipsawed significantly from one year to the next. Consequently, it was nearly impossible to assess the long-term value of planned investments. A single annual price signal — even three years in advance — was not very valuable. It was bad enough for existing DR end-use assets that could be enrolled within a year; for multibillion-dollar generation units with lifespans of 30-40 years, such annual price indicators were next to useless.

Furthermore, the reality of today's generation asset development — characterized by sclerotic interconnection queues, lengthy and complex state and local permitting processes, and a brutally slow supply chain — means that nothing gets built within a three-year time frame even in the most optimistic scenario. To take one example, one cannot even get a new *gas turbine from GE* until 2028/29 at present.

The result of the old three-year forward system was an abundance of "phantom assets" haunting the resource mix — projects that cleared the auction but never were developed. Those shortfalls in capacity subsequently had to be addressed through intermediary reconfiguration auctions. The new prompt auction, taking place just a month ahead of delivery, helps ensure that ISO-NE will secure capacity from actual resources capable of delivering, rather than empty promises from developers who may never see steel in the ground.

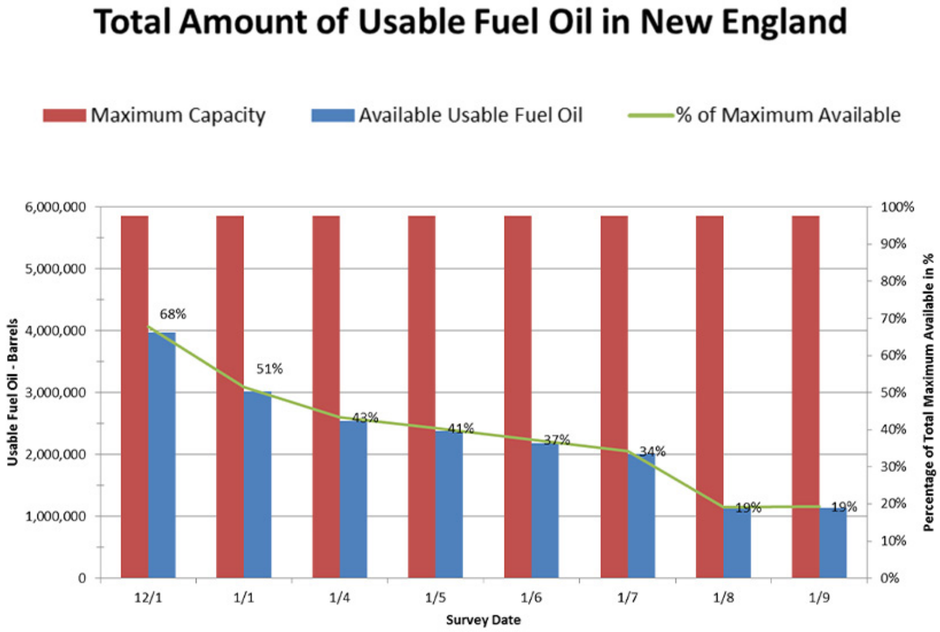
Seasonality: Addressing the Worst Days of Winter

The New England grid operator also changed its approach to seasonality, an approach that is long overdue. While summer heat may challenge the grid, New England's lengthy winter cold snaps are where the greatest risk lies. With only two pipelines feeding the region, on the coldest days there is simply insufficient gas to generate power and keep people warm and safe. In that equation, power generation loses. At that point, the region resorts to its store of fuel oil, which is not limitless.

During the extended cold weather of

Why This Matters

It's probable we're entering an era in which our "friendly little electron" demands a much higher price for the privilege of being there exactly when we need it, writes Peter Kelly-Detwiler.



| ISO-NE

2017/18, for example, New England's generators burned through nearly 3 million gallons of fuel oil reserves, with 2 million gallons consumed over just eight days. As can be seen in the graphic, oil reserves plummeted from 34% to 19% availability during the coldest 24-hour period, meaning the region was perhaps a single day away from rolling blackouts.

ISO-NE's revised approach to capacity planning will address that seasonal challenge by establishing a bifurcated system with summer (June 1 to Oct. 31) and winter (Nov. 1 to May 31) periods. This scheme will differentiate resources based on performance during each season. So, for example, solar may fare well during the summer, while assets with on-site fuel would have an advantage in the winter.

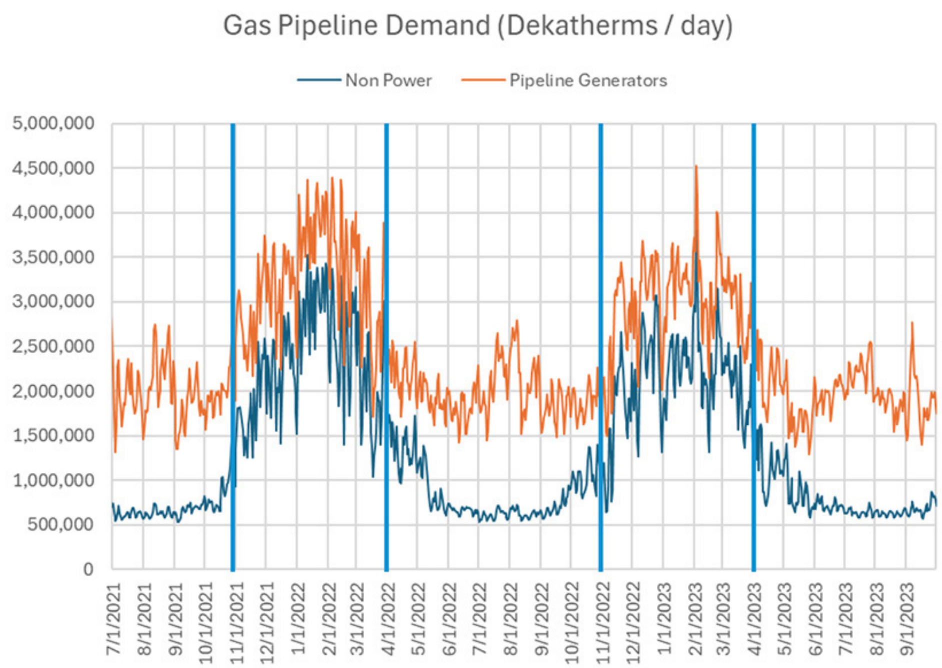
Resource Capacity Accreditation: Who Shows Up When the Party Starts?

ISO-NE's greatest proposed technical change is the way in which capacity resources are "counted." The existing summer performance-based accreditation process will give way to an approach intended to "accurately capture the marginal reliability contribution of resources during the periods that will be of highest risk to reliability." In other words, resources will be rated based on their effectiveness at staving off a blackout when the system is under maximum stress.

The grid operator will evaluate characteristics such as forced outages, output variability and access to fuel. For the reasons discussed above, gas-fired generation may be significantly impacted, with ISO-NE reflecting the effect of "pipeline constraints that can limit the ability of the region's gas-fired resource fleet to obtain fuel during the winter."

Gas units without firm supply contracts are likely to be penalized by this approach, and they should be. They rarely show up to the party when needed, on those days when power generation and other demands are both clamoring for the same gas molecule. As illustrated in ISO-NE's planning document, those two demand peaks are highly coincident.

ISO-NE is not the only grid operator seeing this dynamic. 2021's Winter Storm Uri in Texas and 2022's Winter Storm Elliott in the Mid-Atlantic aptly demonstrated the fact that a megawatt of gas-fired capacity is useless if gas is frozen in at the wellhead or if pipeline pressures fall and generating turbines are starved of fuel.



| ISO-NE

After Elliott, PJM significantly reduced the accredited capacity off gas plants, with combined cycle plants falling from 96% to 79% over one year as a result. ISO-NE's new rules may have a similar effect, so that a 1,000-MW gas plant might be credited for only 700 MW or 800 MW of "reliable" capacity.

A Better Way of Saying Goodbye

ISO-NE is reforming its resource retirement process. Currently, a power plant must signal its retirement four years in advance. With the new approach, plant owners can submit a retirement notification one year in advance. This approach gives owners far better knowledge as to the remaining life of their equipment and the near-term market conditions, allowing them to remain in the market if conditions are favorable.

The Inflationary Bottom Line for the New England Power Market

ISO-NE has asked FERC to approve these revisions by March 31, 2026, with the first affected auction occurring in May 2028 for delivery starting in June. The new approach is more realistic, but it may well have a significant inflationary effect for two reasons.

First, if the experience of PJM holds true, ISO-NE could find itself short of accredited capacity because of its revised accreditation approach. With 42% of 2025's capacity supplied by gas generators, a significant de-rating could cut supply and drive prices up, especially if the demand side heats up.

Second, the seasonal approach may further affect future available capacity figures, especially with the winter re-rating of gas-fired generation, creating additional shortfalls.

And finally, with the capacity auction only a month prior to delivery, there's zero time for the supply side to react to higher prices.

It's probable we're entering an era in which our "friendly little electron" demands a much higher price for the privilege of being there exactly when we need it. So, customers must be prepared to focus more intently than ever before on managing their demand — on a seasonal basis — even as they reluctantly reach for their checkbooks. ■

Around the Corner columnist Peter Kelly-Detwiler of NorthBridge Energy Partners is an industry expert in the complex interaction between power markets and evolving technologies on both sides of the meter.

Utility Ratemaking Has Become More Complicated

Political Landscape Forces Regulators to Consider Wide Array of Social Issues

By Kenneth W. Costello

Kenneth W. Costello

Utility ratemaking comprises three distinct parts: revenue requirements, cost allocation and rate design. Ratemaking is a regulator's prime function, as it determines how much revenue that utilities should collect from customers, from which customers and how.

The ratemaking process is complex and interactive, striving to satisfy or appease groups with diverse goals, interests and agendas. It also entails addressing the several objectives underlying ratemaking, each of which has a distinct effect on the public interest.

Most utility regulators subscribe to what regulatory observers call the *"balancing act"* of regulation. In an ideal world, regulators attempt to balance the interests of the different stakeholders with the overall goal of promoting the general good. This objective complies with the premise behind the public-interest theory of regulation. While ratemaking plays an integral role in achieving the "balancing act," this action has become increasingly difficult for regulators as they have to cope with new interests.

Examples abound in which a particular rate mechanism advances some regulatory objectives while hindering others. The reality is that all rate mechanisms have mixed effects on the public interest. The premise is that when a rate mechanism impedes some regulatory objective it diminishes the public interest, while improving the public interest when it advances an objective. This speaks to the trade-offs regulators must make when deciding on different rate mechanisms.

One example is real-time pricing in which the trade-off is between economic efficiency and price stability. A second example is price caps in which the regulator must weigh the benefits of pricing flexibility and increased incentives for productive efficiency against profit variability, which could lead to "excessive" utility profits. These conflicts inevitably require regulators to make value judgments on the overall desirability of a rate mechanism for the general public.

A third example is cost trackers or riders, in which *a trade-off exists* between timely utility recovery of costs and robust incentives. Trackers and riders allow utilities to recover their costs more quickly and with more certainty, lowering their financial risk; but they also can create incentive problems when: (1) regulators fail to adequately scrutinize those costs, and (2) cost recovery methods differ across different utility functional areas.

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Why This Matters

Energy consultant Kenneth W. Costello questions whether utility regulation has expanded its domain far beyond its original mandate and risks drifting away from its core objectives.

A Risk of Drifting Away from Core Objectives

Today, clean energy, low-income and climate advocates add to the interests that regulators must appease. If regulators try to satisfy more interests, driven by politics or for other reasons, one must ask: Do they therefore risk drifting away from their resolve to achieve core objectives, especially advancing the well-being of utility customers? After all, *the raison d'etre* for public utility regulation is to protect customers from "monopoly" utilities.

What are these other responsibilities that regulators have to take on? The landscape confronting utility regulators requires them to address a wider array of *social issues* that historically were under the purview of the other branches of government or left to the marketplace.

Their ratemaking duties include consideration of affordability for low-income households, the accommodation and even the subsidization of new technologies that compete with utilities' core business, decarbonization of utilities' generation portfolio, and the subsidization of utilities' customers to use less electricity and switch to other electricity sources (e.g., rooftop solar).

No other private business comes to mind in which society compels private firms to tackle such a wide array of social issues. It is legitimate to ask whether utility regulation has expanded its domain far beyond its original mandate and what is socially optimal.

What Happens When Ratemaking Goes Astray

Faulty ratemaking can lead to adverse outcomes, like undue price discrimination, inequity, poor incentives for innovation, economic inefficiencies like uneconomic bypass, misallocation of business risk between customers and shareholders, and financially stressed utilities.

Concerning uneconomic bypass, faulty ratemaking can lead to customers choosing providers that have lower prices but higher costs. A regulated utility with an unregulated affiliate might have an incentive to subsidize the affiliate by shifting some of the affiliate's costs to its core customers (e.g., residential customers).

Good ratemaking always has been *a big challenge* for regulators. It demands both sound analytics and judgment by regulators. Regulators must weigh or prioritize those objectives underlying ratemaking and measure (if possible) the effect of a rate mechanism on each one, as well as on the overall public interest. Assigning weights requires judgment by regulators, while examining the effect demands data and other unbiased information. Although ratemaking is both an art and a science (some compare it to sausage making), it should start with a strong foundation that includes specified objectives and underlying economic principles, like cost causation.

Utility Regulators Know How to Adapt

Developments in the electric industry have required regulators to re-examine their current, longstanding ratemaking practices. Previous experiences show that utility regulators do adapt, although gradually, to a changed economic, technological and political environment by throwing their support to new rate designs and ratemaking mechanisms.

One example is the restructuring of the U.S. electric industry, *starting in the 1970s*, triggered by the discontent of consumer groups (especially industrial customers) from continuous rising electricity rates along with the problems encountered by utilities in getting the regulators to approve pass-throughs of costs, even those prudently incurred but second-guessed because of unexpected circumstances.

Utilities could not incorporate these costs (to a large extent beyond their control) into their rates fast enough to keep their earnings from falling to a critical level. Regulators eventually allowed fuel adjustment clauses (and, to a lesser extent, future test years) to reduce regulatory lag and avert more serious financial difficulties. Regulators also revisited existing rate structures (e.g., declining block rates) to determine whether they satisfied new objectives, like the advancement of energy efficiency and the reduction of carbon emissions.

As its central duty, utility regulation should make well-informed decisions driven toward the public interest. It should strive for balance and fairness. Good regulation weighs legitimate interests and makes decisions based on facts. Regulation decisions should not unduly favor any one interest group over the public interest; they should coincide with the law and the evidentiary record. This idea is especially critical today where good ratemaking has become more important, but harder to achieve. ■

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

Data Centers Can Drive Down Rates and Boost Local Economies

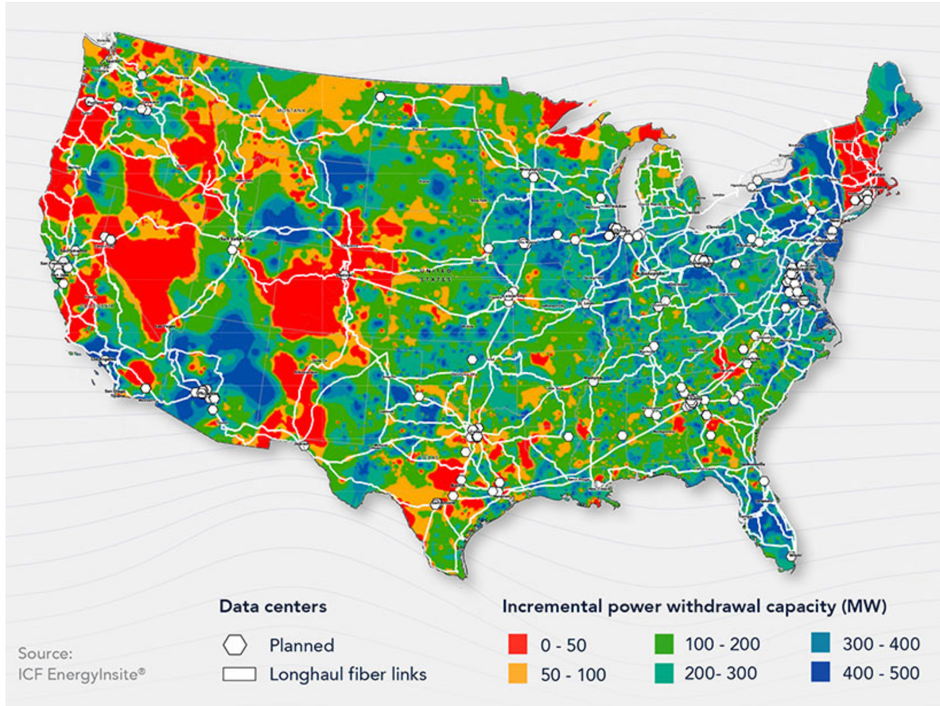
By Nick Myers

Nick Myers

Over the past year, as I have zig-zagged across the country meeting with national and state regulators, the national conversation has centered around one single topic: data centers. Conference after conference, panel after panel all seem to focus on the rapid growth of data centers and the challenge of integrating them into the electric grid while maintaining reliability and keeping rates affordable for customers.

I wholeheartedly agree with the Trump administration's "America's AI Action Plan" when it states that the United States is in a race to achieve global dominance in artificial intelligence (*ai.gov*). I agree that our economic competitiveness, technological achievements and national security in the coming years and decades will largely depend on our AI ecosystem.

So, on the one hand, as a state regulator I know that a wave of data centers is coming. For example, in its recently filed *rate case*, Arizona Public Service (APS) reported that it is contractually committed to serving approximately 3,296 MW of data center load, of which 2,081 MW is from data centers expected to come online by the end of 2028. Further, APS is in conversations with additional data centers representing an additional 16,908 MW of potential load.



Planned data center development overlaid by electric withdrawal capacity and fiber optic networks | *ICF EnergyInsite*

On the other hand, as I travel across Arizona, I consistently hear from residential customers who are understandably concerned that data centers will drive up their rates. Data centers require massive amounts of generation resources and often significant grid upgrades. I understand why residential customers may be concerned. As a regulator, my commitment is to evaluate each new proposal once all the relevant data has been presented and rigorously reviewed.

The good news is that regulators and utilities are fully aware of the potential cost-shift and subsidization problems data centers pose. A commitment to "growth pays for growth" and properly structuring tariffs and energy supply agreements (ESAs) can ensure that data centers are paying all their costs, even if their projected load does not materialize.

Not only that, many residential customers may be unaware that data centers can also apply downward pressure on the rates of all other customers. Instead of driving up residential rates, data centers may help keep them lower. Also, data centers can provide significant economic benefits to local communities. This means data centers not only help advance national AI priorities, but they can also contribute to the flourishing of local communities where they are located.

Data Centers Can Drive Down Rates

Instead of driving up rates, data centers— with properly structured tariffs or ESAs— can help drive down rates for all other customers, including residential customers. Electric utilities have fixed costs (power plants, distribution and transmission lines, substations and so on) that are spread across a utility's customer base. As a utility's customer base grows, these fixed costs are spread across more customers so the average cost per customer goes down.

The same applies when a high-load customer is added to a utility's grid. Because high-load customers, like data centers, use a lot of electricity, they pay a significant share of those fixed costs. Therefore, under standard ratemaking, adding data centers to a utility's customer base will reduce upward pressure on rates for all

Why This Matters

With sound regulatory oversight and a clear commitment to ensuring that growth pays for growth, data centers can strengthen both our electric grid and our local communities, while also advancing national priorities, writes Nick Myers of the Arizona Corporation Commission.

other customers.

Adding data centers to a utility's grid may also result in added grid efficiencies that benefit all customers. For instance, Tucson Electric Power (TEP) *recently explained* that adding a 286-MW data center in its service territory will "reduce the overall cost for TEP to serve all its customers" because the data center's "energy use will help flatten [its] overall system load profile thereby making more efficient use of the grid." This flattening of its load profile will allow TEP "to operate its generation fleet and energy delivery system in a more optimal manner while spreading its fixed cost over a greater volume of energy."

In addition to spreading fixed costs and improving asset utilization, data centers also provide long-term, stable demand that may reduce the financial risk of utilities and lower their borrowing costs to the benefit of all customers. In service territories where load is declining or flat, large new customers like a data center may help maintain revenue adequacy without having to raise rates on existing customers.

Data Centers Can Boost Local Economies

Data centers can also provide significant economic benefits to local communities. According to Loudoun County, Va., the data center industry in the county has significantly reduced the tax burden on residential taxpayers. The county's real property tax rate *has dropped* from $1.285 per $100 assessed value in 2008 down to $0.805 in 2025. Based on the 2025 average assessed value for a residence in the county, this amounts to real estate tax savings of roughly $3,600 a year.

Closer to home, the Arizona Corporation Commission *recently approved* an ESA between TEP and a planned data center in Pima County developed by Beale Infrastructure Group, a $3.6 billion capital investment expected to bring in $152 million *in tax revenues* over 10 years, including $58.5 million to Pima County and $93 million to the state of Arizona. In addition to increased tax revenues that directly benefit local schools, Beale *has committed* to invest an additional $15 million in the community, with $5 million allocated for STEM and trade school education. The data center will also generate 3,000 construction jobs over the multiyear period and 180 on-site jobs by 2029 with an average annual salary of $64,000.

Conclusion

In the end, the data center conversation should focus on two core realities. First, with properly structured tariffs or ESAs that prevent cost-shifts, data centers can help drive down rates for other customers by spreading fixed utility costs across more load, improving grid efficiency and providing stable, long-term demand that benefits all ratepayers. Second, data centers can serve as powerful engines of local economic growth — expanding tax bases, creating high-quality jobs and attracting significant private investment. With sound regulatory oversight and a clear commitment to ensuring that growth pays for growth, data centers can strengthen both our electric grid and our local communities, while also advancing national priorities. ■

— Nick Myers is chairman of the Arizona Corporation Commission.

Dominion Wins Injunction, Can Restart Offshore Wind Construction

Federal Stop-work Order Lifted for 3rd Time in Week

By John Cropley

A federal judge has granted Dominion Energy a preliminary injunction against the stop-work order the Trump administration slapped on the nation's largest offshore wind project.

In response, *Dominion said* it would resume construction of Coastal Virginia Offshore Wind (CVOW) and hopes to begin exporting electricity in a matter of weeks.

The Jan. 16 ruling by Judge Jamar K. Walker in U.S. District Court for the Eastern District of Virginia (2:25-cv-00830) was the third such injunction issued in five days, each by a different judge, two of whom had been appointed by Republican presidents.

Counting the September 2025 injunction against an earlier stop-work order, the CVOW ruling dropped the Trump administration's court record on these orders to 0-4.

Work on all five wind farms under construction in U.S. waters was halted Dec. 22 by a Department of Interior directive that cited national security concerns including radar interference.

Developers of all five separately challenged the move in court, starting with CVOW on Dec. 23, then Revolution, Empire, Sunrise and finally, on Jan. 15, Vineyard.

Revolution, which in September secured an injunction against the stop-work order slapped on it alone, won an injunction against the blanket stop-work order Jan. 12. Empire secured its injunction Jan. 15.

Why This Matters

The offshore wind industry is winning in its efforts to complete the work it started in U.S. waters before President Donald Trump was re-elected.

As it promotes fossil fuel and nuclear power development, the Trump administration has moved to thwart renewable energy development to varying degrees, with some emissions-free technologies treated more harshly than others. The president himself has voiced a particular animus for offshore wind, though, and the stop-work orders are just one chapter in his continual campaign against it.

As *Revolution*, *Empire* and now *CVOW* have succeeded in pausing this latest attack, their statements indicate they view the injunctions as progress, not victory.

Dominion said Jan. 16: "While our legal challenge proceeds, we will continue seeking a durable resolution of this matter through cooperation with the federal government."

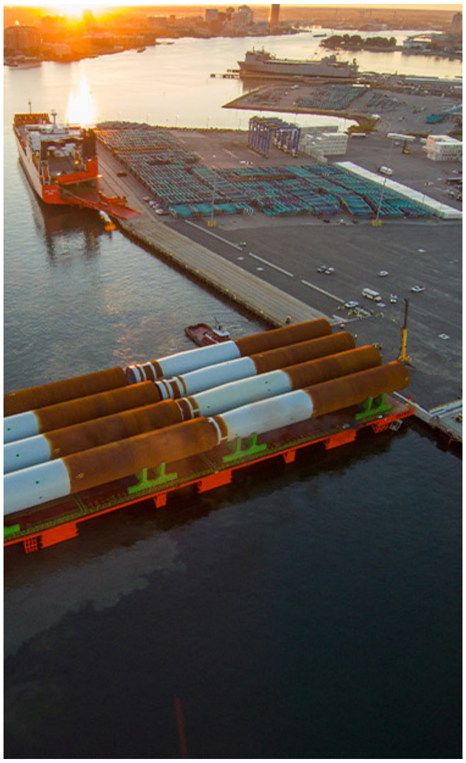
CVOW has a nameplate capacity of 2.6 GW — nearly three times more than the next-largest U.S. project — and will feed a grid that has capacity concerns.

PJM on Jan. 9 submitted an amicus brief supporting CVOW's attempt to lift the stop-work order. It wrote: "Given the long lead times associated with the development of any alternative new generation, let alone delay of this project, extended delay of construction and operation of the CVOW project will cause irreparable harm to the 67 million Americans served by PJM given this region's (including Virginia's) critical need for new generation resources to achieve commercial operation in the next few years."

CVOW has been in the works for more than a decade; recent increases pushed its price tag to more than $11 billion.

Unlike the other four projects, however, CVOW's developer also is its offtaker. Dominion's ratepayers still will be on the hook for the cost of the project if it does not generate electricity. The developers of the other projects will recoup their multibillion-dollar investments only through electricity sales.

Along with ratepayers and electric grids, Trump's campaign against offshore wind threatens an industry that was creating jobs and economic activity.



The first monopile foundations for the Coastal Virginia Offshore Wind project arrive in Portsmouth, Va., in October 2023. | *Dominion Energy*

North America's Building Trades Unions also filed amicus briefs against the stop-work orders. On Jan. 16, it said: "We applaud this week's federal court rulings restarting U.S. offshore wind projects. … The shutdown order stalled every East Coast offshore wind project, freezing massive builds in place and sidelining our members, local communities and urgently needed domestic energy supply."

Even as it suffers setbacks in court, the Trump administration's efforts against offshore wind have succeeded in an important sense: They have created such an atmosphere of financial risk and regulatory uncertainty that most developers have suspended or canceled their U.S. plans.

The five projects under construction now appear likely to be the last in U.S. water for years to come. They total 5.8 GW, a far cry from the 30-GW goal the Biden administration set for 2030. ■

Judge Allows Construction to Resume on Empire Wind

Ruling is 2nd Win for U.S. Offshore Wind Sector as it Fights Blanket Stop-work Order

By John Cropley

Equinor has won a temporary injunction against the Trump administration's stop-work order on U.S. offshore wind projects, allowing it to resume work on Empire Wind.

The Department of the Interior on Dec. 22 shut down work on all five projects under construction in U.S. waters, citing national security concerns.

Empire, which incurred millions of dollars in added costs from a monthlong stop-work order in April and May 2025, filed a challenge to the new stop-work order Jan. 2 and a motion for preliminary injunction Jan. 6 in U.S. District Court for the District of Columbia (1:26-cv-00004).

After a Jan. 14 hearing, *District Judge Carl Nichols* — appointed to the federal bench by President Donald Trump in 2019 — granted the motion Jan. 15.

Equinor, which holds an offtake contract with New York for the 810-MW Empire Wind project, had told the court it likely would need to abandon the project if it could not resume work by Jan. 16. With any further delay, it said, crews would not be able to finish a key component before the specialized installation vessels had to depart for the next contracted work.

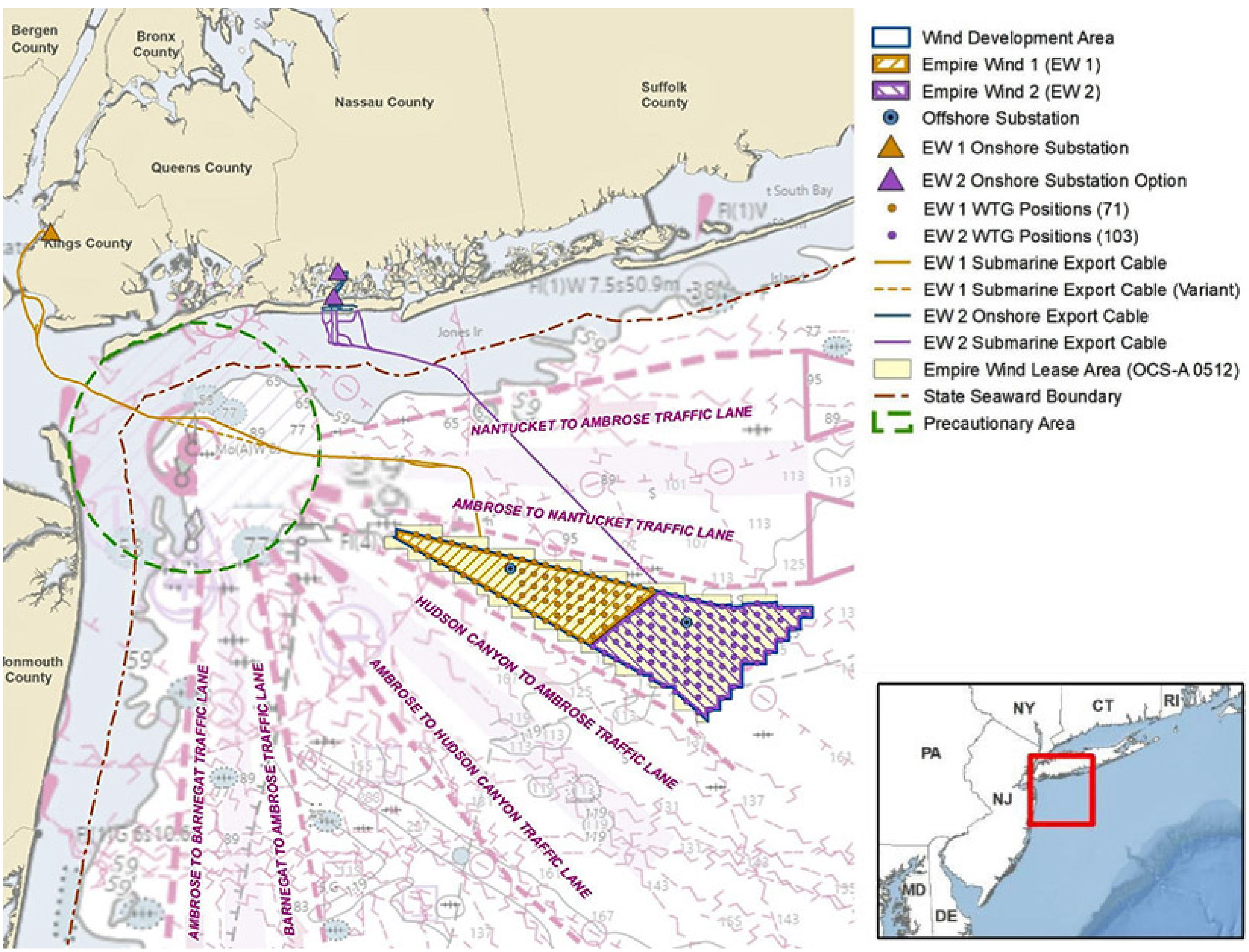
Later Jan. 15, Equinor said: "Empire Wind will now focus on safely restarting construction activities that were halted during the suspension period. In addition, the project will continue to engage with the U.S. government to ensure the safe, secure and responsible execution of its operations."

Why This Matters

The court ruling is a symbolic if not permanent win for the struggling U.S. offshore wind sector.

It was the second court victory this week for the beleaguered U.S. offshore wind sector.

On Jan. 12, another Republican-appointed federal judge lifted the stop-work order



The Empire Wind lease area and cable routes are mapped off the coast of New York. A judge has lifted a stop-work order on Empire Wind 1. | *BOEM* on Revolution Wind, a 704-MW project nearing completion off the New England coast. (See *Judge Again Lifts Revolution Wind Stop-work Order*.) The same judge also lifted the Trump administration's August stop-work order against Revolution.

Meanwhile, Dominion Energy is contesting the stop-work order on Coastal Virginia Offshore Wind, a 2.6-GW wind farm near completion, and Ørsted is fighting to restart work on the 924-MW Sunrise Wind, an earlier-stage New York project. (See *Offshore Wind Developers Fight to get Back in the Water*.)

Vineyard Wind was the last project to join the legal fray. On Jan. 15, it filed a complaint in U.S. District Court in Massachusetts (1:26-cv-10156) asking the court to declare the stop-work order unlawful and allow work to resume.

The Avangrid-Copenhagen Infrastructure Partners joint venture is 95% complete and already able to send 572 MW of its planned 800-MW capacity to the New England grid, according to the court filing. Construction began in 2021 and was on track to be completed by March 31.

In a statement, *the developers said* they will continue to work with federal regulators to understand the matters raised in the stop-work order but believe the order was unlawful and said if it is not promptly enjoined, it will cause immediate and irreparable harm to the project and the communities that will benefit from it.

Despite the setbacks it has sustained in court, the Trump administration has succeeded to a significant degree in its bid to thwart offshore wind development: The level of risk it has created has scared away further investment.

The five offshore wind projects hit with the Dec. 22 stop-work order constitute the entire large-scale U.S. offshore wind sector, and they appear unlikely to be followed by others anytime soon. To cite the obvious example, Empire Wind 2 has been shelved indefinitely.

Oceantic Network welcomed the Jan. 15 ruling: "Empire Wind is critical to securing New York's electric grid, stabilizing rising energy costs for local communities, creating jobs and achieving energy independence, underscoring the importance of building out America's energy infrastructure to meet rising electricity demand."

Regional Plan Association hailed the win but warned it is not a final victory: "Despite the good news of these decisions, they still do not ensure that these projects will be completed. The court rulings are temporary injunctions that allow the companies to continue to build while the lawsuits against the administration's efforts to stop them make their way through the courts. Even an ultimate victory against the administration's freeze — based on supposed national security concerns — does not prevent them from taking additional steps to disrupt, delay or cease the projects."

Advanced Energy United said: "Restarting Empire Wind is a major win. This project will deliver clean power and local jobs exactly when we need them the most. Today's ruling shows that smart energy planning beats political games every time — and that delaying critical projects only drives up costs for consumers." ■

Energy Hub and Brattle Study Finds Big Savings from Managed EV Charging

By James Downing

Energy Hub and Brattle Group released a *report* showing that utilities can achieve significant savings if they actively manage electric vehicle charging.

"Demonstrating the Full Value of Managed Electric Vehicle Charging" includes the results of a real trial of 58 EV drivers in Washington state who got $100 upfront and $10 per month when they limited opt-outs to three or fewer in a month. They were tested for four weeks with time-of-use rates. Energy Hub actively managed their charging using an unmanaged baseline on flat, volumetric rates.

"We found that with the solution, it enabled distribution utilities to host over twice the number of EVs on the same system as if they were unmanaged," Energy Hub CEO Seth Thompson said in an interview. "So, it kind of doubles the distribution grid's EV hosting capacity just by managing the EV charging load and in terms of cost impacts. We found that in the long term, it could bring the cost of hosting EVs from about $800 per year per EV if they were unmanaged, to about half of that if they were managed."

Energy Hub's main business is to contract with utilities to manage EVs and distributed energy resources (DERs) on their systems.

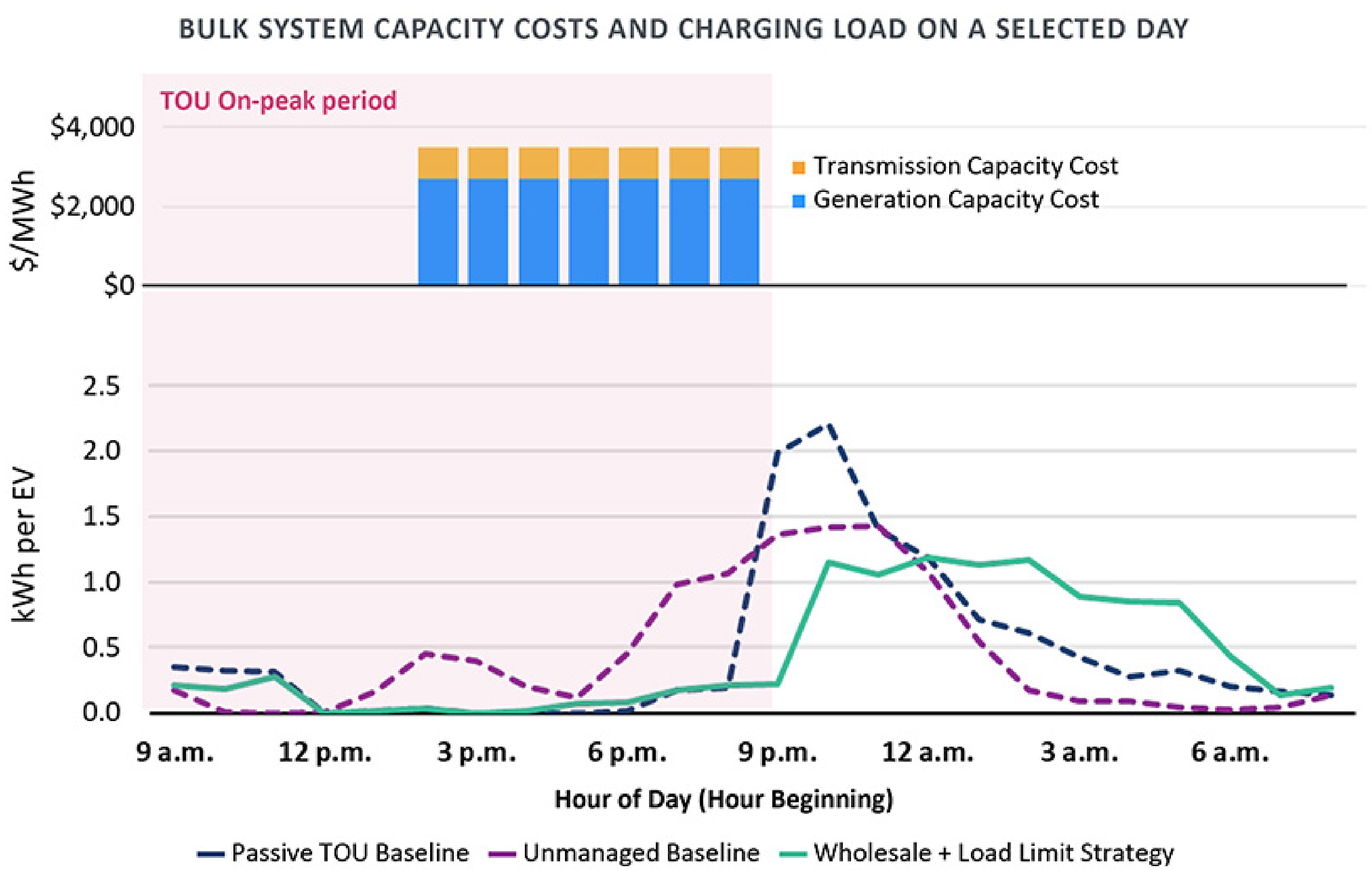
In the past, a lot of that work was focused on replicating a peaker plant with distributed resources. But as EVs become more common, the industry needs a way to manage their impact on distribution circuits.

"EVs clearly were starting to apply a degree of pressure to the distribution grid where the sort of traditional idea of a one-time or occasional, discrete activation of a VPP [virtual power plant] was not what the grid needed," Thompson said. "The grid needed a system that sits there running all the time, protecting the system from overloads and essentially just moving load around to raise your utilization factor. That's the future of VPPs, to be able to do both of those things."

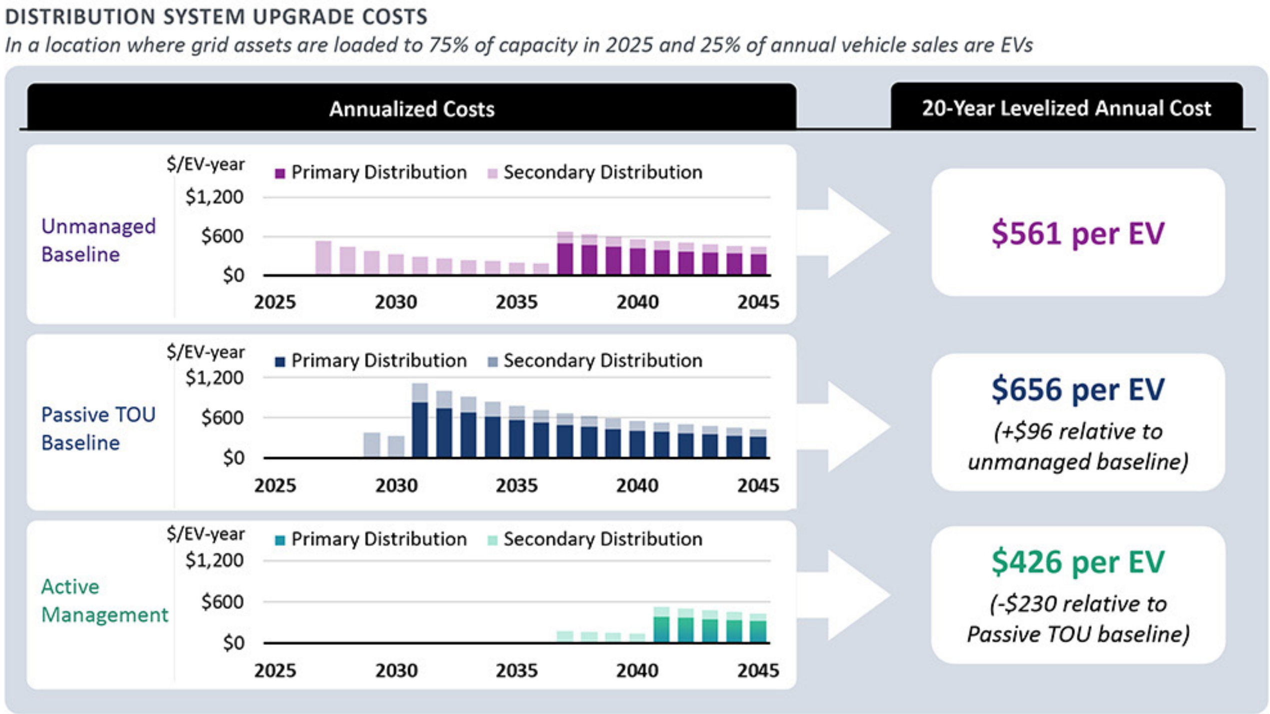
Active managing of EV charging delivers 95% of that load to off-peak hours, which helps cut customer bills. A more passive

Why This Matters

The report shows that managing EV charging can lead to significant benefits, such as delaying distribution system investment by allowing the existing system to handle more charging load.



A graph from the report showing EV load profiles over a day based on different management styles. | *Brattle*



A chart from the report showing the costs in system upgrades per EV by different charge management styles. | *Brattle*

approach using time-of-use (TOU) rates (with lower off-peak charges) can deliver similar benefits when EV penetration is low, but it can exacerbate peaks when too many EVs are on one distribution circuit, Brattle managing associate and report co-author Akhilesh Ramakrishnan said in an interview.

"It's not a generalized finding about TOU, but it's specific to the type of load that EVs are, where they're basically this kind of huge load that's coming from one source," he added. "EVs can be double the peak load of a typical house, and so you really don't want all of these things charging and discharging at the same time."

With passive TOU rates, customers would set their EVs to start charging once the cheaper power kicks in and everyone on the block would start pulling power at the same time, leading to a larger peak than even flat rates. Energy Hub's management system can spread those charges over the entirety of the off-peak hours, flattening the peak.

"Every EV will let you set a charging schedule, and essentially, if you were trying to do this through behavior change, the more successful you are at getting everybody to pay attention to that black-and-white pricing signal, the greater the peak," Thompson said. "And so, the ideal combination is a mix of the TOU signal and a piece of software that kind of randomizes and distributes that strategically over time."

The study looked only at TOU rates, which offer discounts in off-peak hours. Thompson argued that more complex rates, like passing through wholesale costs, do not attract customers.

"If you go around Europe, if you go to Australia, in major other markets, the per capita participation with flexible loads is lower than it is in the U.S.," Thompson said.

Energy Hub's and other distributed energy resource management systems can link up EVs, solar panels, smart thermostats and other resources to those wholesale signals and optimize their performance for the grid, Thompson said.

The need for that management scales up with EVs on the system. Ramakrishnan said a local grid can handle a car or two but that once more start to plug in, their charges need to be managed to avoid the need for distribution upgrades.

"You can assume there's a random distribution of these things up to a point, and you never know whether you're already basically at capacity or there's tons of headroom," Thompson said. "The other thing that you hear from utilities all the time is that there's clustering, and so you might have 5 or 10% adoption in the service territory, but you might have 25% in a neighborhood."

The market changed for EVs in general in 2025 as federal tax incentives expired at the end of the third quarter. That led to a spike in purchases as consumers sought to take advantage of those, Thompson said.

Now the industry is waiting for new quarterly figures to get a sense of how fast EV sales will grow absent federal tax incentives. Even with those incentives, most of the plug-in models were more expensive, which kept their sales numbers low. With technology improving, prices are expected to come down and that could lead to significant growth.

"We now have the ability to tackle this in an orderly way," Thompson said. "What's nice about the way we've built this solution is that a utility can adopt it very cost effectively at small scale, get comfortable with sort of understanding what does it do? How does it work? How do they integrate it with our other systems?"

Once they begin building consumer awareness, "as they hit these levels of kind of a critical mass, whether that's locationally or across their whole system, they're ready for it," he added. ■

EIA Predicts Sustained Power Growth in 2026 and 2027

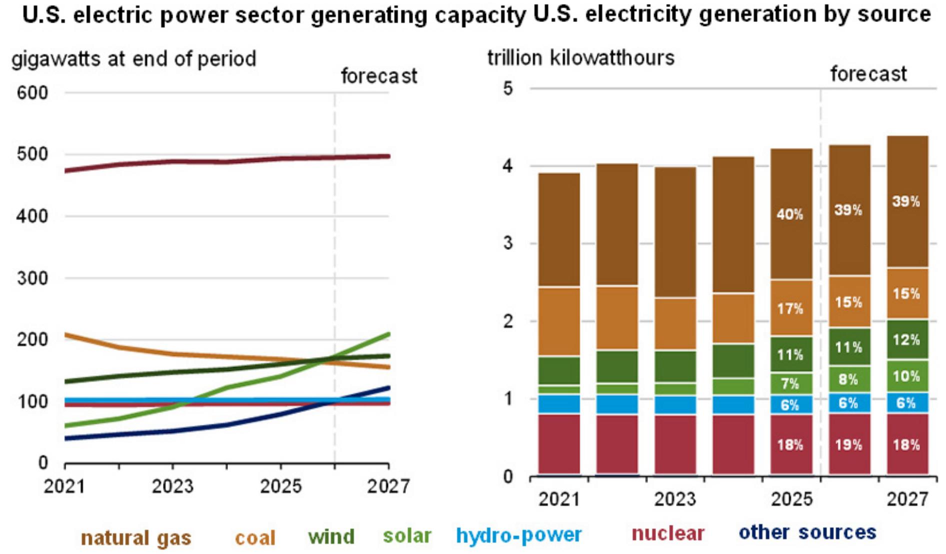
Increases of 1%, 3% Would Yield Strongest 4-Year U.S. Growth in Quarter Century

By John Cropley

The U.S. Energy Information Administration (EIA) is forecasting the highest power demand growth in a quarter century in 2026 and 2027, largely due to the proliferation of data centers.

The predicted 1 and 3% growth in 2026 and 2027 would be the first time since 2007 that power demand has increased four years in a row and would be the largest four-year increase since 2000, *EIA said Jan. 13*.

EIA's *January 2026 Short-Term Energy Outlook* also projects that solar power output will continue its sharp growth, natural gas will provide a slightly smaller percentage of U.S. electricity and coal will resume its decline.



The EIA projects significant growth for U.S. solar energy through 2027. | *EIA*

EIA predicts:

- Solar generation will increase by more than 20% in both 2026 and 2027, giving it 10% of U.S. power generation by the end of 2027, up from just 5% in 2024.
- Natural gas generation will be unchanged in 2026 and increase 1% in 2027; this gives it a 39% share of the power supply in both years, down from 40% in 2025 and 42% in 2024.
- Coal will provide 15% of U.S. power in 2026 and 2027, down from 17% in 2025 and 16% in 2024.
- Wind power will tick up from 11% to 12% of the power supply.
- Nuclear and conventional hydropower will hold steady from 2024 to 2027, with nuclear providing 18 or 19% of the nation's power and hydro 6%.
- The benchmark Henry Hub price for natural gas will start to increase in 2027 on higher natural gas consumption in the electric power sector and growing demand for LNG exports, with three new export facilities coming online.

Why This Matters

The projections quantify the demand expected from new large loads and specify the generation mix that will meet those demands.

"U.S. energy production remains strong, and natural gas output is expected to grow to nearly 109 billion cubic feet per day this year," EIA Administrator Tristan Abbey said in the news release. "Natural gas supply is critical as we forecast that U.S. liquefied natural gas exports expand and electricity demand rises through 2027, driven largely by increasing demand from large computing facilities, including data centers."

The increases are a marked change from the early part of this century — EIA reports that U.S. electricity consumption increased by an *average of only 0.1% per year* from 2005 to 2020.

Other projections from EIA's *January outlook* include:

- Power demand growth is being driven in part by data centers and other commercial users; as a group, they bought 2.4% more electricity in 2025 and are projected to buy 2.4 and 4.3% more in 2026 and 2027.
- The industrial sector, by contrast, is expected to see 1.6 and 3.4% growth in 2026 and 2027 after 1.7% growth in 2025.
- Total generation by the electric power sector increased 2.5% in 2025 to nearly 4,300 BkWh; it is expected to increase 1% in 2026 and 3% in 2027.
- The 4% decrease in natural gas generation and the 13% increase in coal generation seen in 2025 were both due largely to higher natural gas prices.
- Coal generation will decline 9% in 2026 and be nearly unchanged in 2027; even with deferred coal plant retirements, coal generating capacity is expected to decline by 13 GW — nearly 8% — over the two years.
- Nuclear power generation will increase 2% in 2026, largely due to the anticipated Palisades nuclear plant restart, but no change is expected in 2027.
- Wind power generation will increase 6% in both 2026 and 2027, even factoring in the uncertainty facing the offshore wind sector.
- Solar will hit 171.3 GW of installed capacity in the fourth quarter of 2026, finally surpassing wind (170.7 GW) as the *leading U.S. renewable* by nameplate capacity and becoming second only to natural gas (495.1 GW) among all forms of power generation.
- However, solar's low capacity factor will leave it fifth among the six major types of power generation sources in 2026, *providing 8% of U.S. power*; only hydropower — 6% — will be lower. ■

Judge Rules Blue-state Energy Grant Terminations Unlawful

DOE Targeted 321 Biden-era Awards in States Trump Did not Carry in 2024 Election

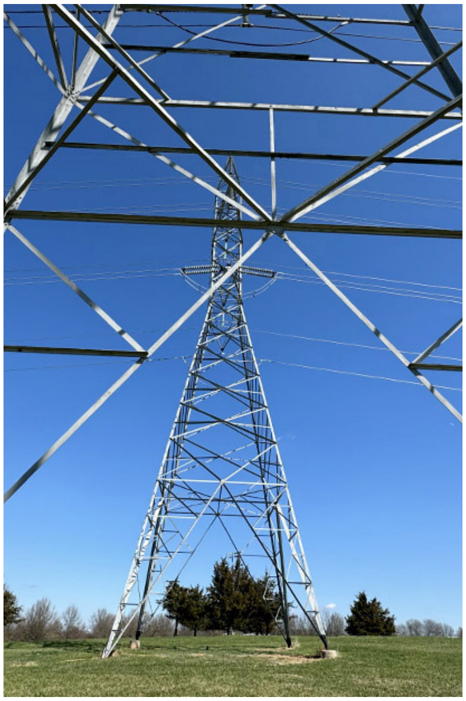
By John Cropley

A federal judge has ruled the U.S. Department of Energy acted illegally when it terminated several energy grants because they were based in Democratic-leaning states.

The ruling stems from the controversial cancelation of $7.56 billion worth of Biden-era grants in October 2025. A month later, the city of St. Paul, Minn., and five organizations challenged the cancellation of nine grants earmarked for them.

Judge Amit Mehta in the U.S. District Court for the District of Columbia *ruled Jan. 12* that the grant cancellations violated the guarantee of equal protection of laws under the Fifth Amendment of the U.S. Constitution (25-cv-03899).

All 223 projects that were to receive the 321 grants (except one in Canada) are in states Kamala Harris carried in the 2024 presidential election. Moreover, Mehta noted, the defendants admitted that a primary reason for selecting which DOE grants to cancel was whether the grantee was in a "blue state."



A federal judge has ruled the Trump administration's termination of $7.56 billion in Biden-era energy grants was illegal. | © *RTO Insider*

Similar grants in "red states" that Donald Trump carried in the 2024 election were spared from termination, Mehta wrote, and the defendants conceded those grants were comparable to the terminated grants.

The judge specifically cites Grid Resilience and Innovation Partnership and methane emissions monitoring grants that were awarded to both red and blue states but terminated only in blue states.

The defendants asserted partisan politics does not offend the Equal Protection Clause and compared it to the common practice of federal pork barrel spending.

But that analogy falls flat, Mehta wrote, because members of Congress securing money for their districts is wholly different from an agency taking away congressionally appropriated funds that already have been awarded. Further, pork-barrel spending can rationally be related to a legitimate government interest.

The plaintiffs, Mehta wrote, do not dispute that the defendants proffered a legitimate purpose for this: administering grant programs consistent with the agency's priorities. The question, he said, is whether the classification the defendants drew is rationally related to the purpose.

Mehta then answered the question: "It is not. Without more [evidence], there is no reason to believe that terminating an award to a recipient located in a state whose citizens tend to vote for Democratic candidates — and, particularly, voted against President Trump — furthers the agency's energy priorities any more than terminating a similar grant of a recipient in a state whose citizens tend to vote for Republican candidates or voted for President Trump."

Mehta ruled the termination unlawful and vacated the October termination notices to the seven awards at issue in the litigation. He directed the plaintiffs to indicate by Jan. 16 whether they will seek injunctive relief and/or compensation for attorney's fees.

Why This Matters

The judge ruled that penalizing states Trump did not carry in the 2024 election violates the Constitution.

In response, a DOE spokesperson said Jan. 13: "We disagree with the judge's decision and stand by our review process, which evaluated these awards individually and determined they did not meet the standards necessary to justify the continued spending of taxpayer dollars. The American people deserve a government that is accountable and responsible in managing taxpayer funds."

DOE's *Oct. 2 announcement* of the grant terminations indicated many of the grants were awarded during the lame-duck phase of Joe Biden's presidency but did not indicate where the recipient projects were based: California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Maryland, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, New York, Oregon, Vermont and Washington. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

All are blue states, but in some cases, the impact of the cancellations would stretch into red states.

St. Paul *was joined in the Nov. 10 complaint* by Elevate Energy, the Environmental Defense Fund (EDF), the Interstate Renewable Energy Council, Plug In America and Southeast Community Organization as plaintiffs.

EDF was party to four awards totaling $535.5 million. The other five were designated to receive small grants ranging from $1.2 million to $6.9 million. Mehta's ruling pertains to seven grants totaling $27.6 million.

Named as defendants were DOE, Secretary of Energy Chris Wright, the Office of Management and Budget and its director, Russell Vought. ■

Colo. Officials Push Back on Craig Coal Plant Extension

PUC Urged to Not Backslide on Climate Goals

By Elaine Goodman

Local elected officials in Colorado are speaking out against the Trump administration's order to keep the coal-fired Craig Generating Station Unit 1 available to operate past its planned retirement date.

The officials addressed the Colorado Public Utilities Commission during the public comment portion of the Jan. 14 meeting.

"It is painfully clear that the federal government currently has not only abandoned climate-sensitive policies and fuel choices, but that it is actively seeking to destroy a durable climate and to return to the damaging fuel sources that got us into this pickle in the first place," said Glenwood Springs City Council member Steve Smith.

The U.S. Department of Energy issued an emergency order Dec. 30 to Tri-State Generation and Transmission Association and other co-owners of Craig Station Unit 1 to keep the unit available to operate. Unit 1 was slated to retire Dec. 31; Tri-State said it had planned for adequate resources to maintain reliability after the unit retired. (See *DOE Blocks Retirement of Another Coal-fired Plant*.)

A DOE *news release* said the order was to ensure access to "affordable, reliable" electricity through the winter. The order is in effect through March 30.

Tri-State said in a release that Unit 1 was hit by an outage Dec. 19 due to a valve failure. But Tri-State has a "100% compliance" policy, CEO Duane Highley said, and planned to take needed steps to repair the valve.

Why This Matters

Local officials say the Trump administration's coal plant extensions are fueling concerns about wildfires and impacts to the outdoor recreation based economy.

The coal-fired Craig Generating Station in Moffat County, Colo | *Tri-State Generation and Transmission Association*

Local officials said their communities are ready for the coal plant to close.

"[The] heavy-handed order to Tri-State to keep the Craig Unit 1 coal plant open flies in the face of Colorado law, Tri-State's bottom line and what people in Craig and Moffat County want," Ridgway Mayor John Clark told the PUC.

Speakers pointed to the impact that climate change is already having on their communities.

Broomfield City Council member Sean McKenzie said a grass fire that broke out in the community Jan. 5 was quickly contained, but sparked memories of the devastating Marshall Fire in December 2021 that destroyed 1,084 homes.

"The conditions that were once reserved for July are now visiting us in January," McKenzie said. He urged commissioners to "uphold the policies you've worked so hard to put in place."

Basalt City Council member Hannah Berman called climate change an "existential threat" to the area's economy, which relies on outdoor recreation. She asked the PUC to "take any and all action they can to ensure that Colorado continues to transition off of coal power as mandated by Colorado law."

Adams County Commissioner Emma Pinter warned the commission that now is not the time to backslide on climate goals.

"In Colorado, our climate emission goals still stand and must be achieved," Pinter said. "This commission needs to work to ensure that we meet all of our climate goals in spite of any federal efforts to the contrary." ■

Wash. AG, Environmental Groups Challenge DOE's Centralia Coal Plant Order

DOE's Authority, Intent Questioned in Separate Rehearing Requests

By Robert Mullin

Washington's attorney general and a coalition of environmental groups have mounted separate challenges to the U.S. Department of Energy's December decision to order TransAlta to continue operating the state's last coal-fired plant for three months beyond its scheduled retirement at the end of 2025.

Attorney General Nick Brown and the coalition — which includes Earthjustice, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Sierra Club and the Environmental Defense Fund — have separately filed requests to rehear DOE's Dec. 16, 2025, order to keep the Centralia Power Plant's 670-MW Unit 2 running until March 16, 2026, due to an energy "emergency" in the Pacific Northwest this winter. (See *DOE Orders Retiring Wash. Coal Plant to Stay Online for Winter*.)

The order was one in a series of such moves the Trump administration's DOE has taken over the past year to extend the life of aging fossil fuel-fired plants slated for closure, including in *Michigan*, *Pennsylvania* and *Colorado*.

"The Trump administration is once again ignoring both the law and the facts," Gov. Bob Ferguson said in a Jan. 13 *statement* accompanying announcement of the state's *request*, which asks DOE to "immediately withdraw" the order. "DOE needs to reverse course on this harmful and misinformed order."

"DOE is misusing its narrow authority reserved for imminent emergencies to force a dirty, inefficient coal plant to keep operating," Earthjustice attorney Patti Goldman said in a Jan. 14 *statement* by the coalition. "Our region has moved beyond reliance on coal and this plant. We are meeting our region's energy needs, now and into the future, with cleaner sources."

Why This Matters

DOE critics continue to argue that keeping coal plants open under Section 202(c) of the Federal Power Act misinterprets the law, which is intended to address only "real" emergencies.

TransAlta's Centralia Power Plant in Centralia, Wash. | *Washington Dept. of Ecology*

In their statements, the AG's office and the coalition questioned DOE's authority to keep the Centralia plant open under Section 202(c) of the Federal Power Act — and the department's reason for doing so, arguing that the law is intended to address only "real" emergencies.

The coalition contended that the order "exceeds that authority and instead tries to impose the administration's preference for coal-fired power over a 2011 agreement between the state of Washington and TransAlta, the owner of the plant, to shut down the plant by the end of this year." (Unit 1 at Centralia was shut down in 2020 under the first phase of that agreement, and TransAlta plans to convert the facility to natural gas.)

The AG said the order "is a clear attempt by DOE to bypass the limits imposed on it by Congress."

In its rehearing request, the AG said the department failed "to properly identify or clarify the appropriate entities that have any authority to direct" Centralia's operation. The Dec. 16 order called on TransAlta to "take all measures necessary" to ensure the plant is available operated at the direction of either the Bonneville Power Administration as a balancing authority or CAISO's RC West as the regions reliability coordinator, but it was apparent neither of those entities was consulted before the order was issued.

Getting the Story Straight

The coalition in its *rehearing request* argued that DOE failed to provide evidence of an energy emergency or electricity shortage that warranted continued operation of the plant. It notes that two third-party studies cited by DOE to support its order "demonstrate the absence of an emergency."

The coalition points out that the first study, NERC's assessment of reliability for this winter, "expressly states that 'operating reserve margins are expected to be met after imports in all winter scenarios.' … This means that the study on which the department relies anticipates that the region will be able to meet peak demand and maintain the full added buffer of reserves on top."

The second study, by Energy and Environmental Economics (E3), has not yet been released, the coalition noted. Instead, DOE based its finding on a September 2025 presentation on the pending study, whose author has said shows the Northwest's resource adequacy risk is "slightly elevated above the target risk," which "was calculated to achieve a loss of load expectation of one event-day per decade."

"E3 also confirms that it calculated this 'slightly elevated' risk without examining the actual conditions this winter; as a planning document, the presentation is based on a historical model and does not reflect actual weather and hydrological conditions presently existing for this winter," the coalition wrote in the rehearing request.

The coalition contends that recent actions by DOE undercut the department's claim of an emergency, including an October 2025 *order* by the Grid Deployment Office that allowed the Northwest to export electricity to Canada based on a finding (in DOE's own words) "that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders."

In that order, DOE itself pointed to the "comprehensive" reliability processes in the region that ensure "bulk-power system owners, operators and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export," the coalition noted.

"The Trump administration can't get its story straight," Tyson Slocum, Public Citizen's Energy Program director, said in the coalition's statement. "While it claims the West Coast is in a state of emergency requiring families to bail out an expensive coal plant, Trump's Department of Energy is simultaneously concluding the region has energy abundance to authorize electricity exports to Canada. Which is it, Donald?"

The coalition contends that complying with the DOE order will "be expensive, as Centralia does not have the coal, customers or workforce to keep the coal plant running. Other coal plants forced to keep operating are experiencing extremely high costs, which [FERC] can require ratepayers to pay."

The groups point to the pollution impact of the order, and how it violates Washington's Clean Energy Transformation Act, which required the state's utilities to stop using electricity from coal-fired plants by the end of 2025.

"So many of us — from state leaders and utilities to elected officials and public interest groups — have worked for decades to plan for and build cleaner, more efficient generation and transmission that will ensure Washington state's transition to clean energy while keeping energy affordable and reliable," said Lauren McCloy of the NW Energy Coalition. "That work is ongoing, and burning more coal at Centralia is not the answer to meeting growing energy demand in the Northwest."

Asked to comment on the challenge, a DOE spokesperson responded: "Under the disastrous energy subtraction policies of the previous administration, the U.S. was on track to lose 100 GW of reliable generation capacity by 2030. Much of the U.S. is now at 'elevated risk' of blackouts under extreme conditions, which NERC declared a 'five-alarm fire' for grid reliability.

"At the same time, the U.S. may need to build 100 GW of new reliable capacity to win the AI race and onshore manufacturing. The Trump administration is committed to preventing the premature retirement of baseload power plants and building as much reliable, dispatchable generation as possible to achieve energy dominance." ■

NV Energy Says it Might Fall Short of State RPS

Renewable Project Hurdles and Federal AI Policy Posing Challenges

By Elaine Goodman

Facing surging electricity demand from data centers and artificial intelligence, NV Energy might soon be struggling to meet Nevada's renewable portfolio standard.

That's according to Janet Wells, NV Energy's vice president of resource planning, who led a Jan. 14 stakeholder meeting on the company's 2026 integrated resource plan.

Wells said the company expects to face challenges in meeting the RPS "for several years."

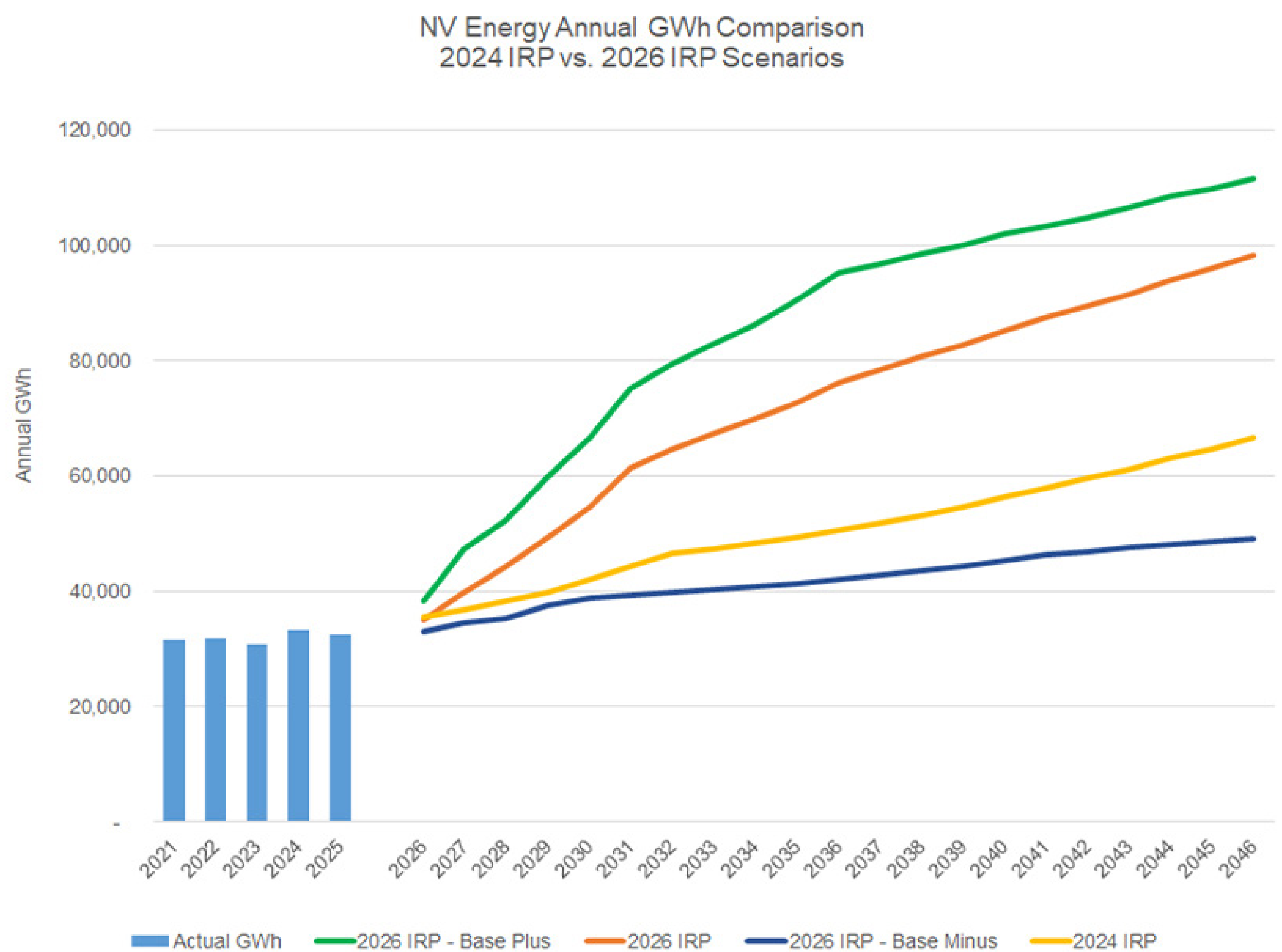
"Federal policy has reduced the deliverability of new renewable resources while also increasing energy needs to support the [federal] AI action plan," Wells said. "That combination will create challenges in meeting the RPS compliance."

> **Why This Matters**
>
> NV Energy's potential non-compliance with Nevada's renewable portfolio standard signals a possible slowdown for the state in meeting its climate goals.

Among those challenges are soon-expiring federal tax credits for solar and wind projects, federal policy shifts on solar and wind, and potential tariff impact on imports, Wells said previously.

If the company misses the RPS target, it will ask regulators for a compliance waiver, Wells said.

NV Energy thus far has been meeting the state's RPS, which requires a certain percentage of electricity sales to come from renewable resources. The RPS increased from 29% in 2022-23 to 34% in 2024-2026, 42% in 2027-2029, and 50% in 2030 and beyond. In 2024, the company exceeded the standard with 46.8% renewables.



NV Energy load forecast. "Base minus" excludes large data center and AI projects, while "base plus" assumes that all load will materialize from large customer projects with signed contracts. | *NV Energy*

Load Forecasts Unveiled

The stakeholder meeting was a follow-up to one held in December regarding NV Energy's 2026 integrated resource plan, which it expects to file in late April. (See *NV Energy's Early IRP Filing Reflects Load, Resource Challenges in 2026*.)

At the January meeting, Wells provided more detail on the load forecast on which the new IRP will be based.

A load forecast for the company's 2024 IRP predicted system growth of 31,000 GWh over 20 years, or a compound annual growth rate of 3.2%.

In the new forecast, electricity sales from 2026-2046 are expected to reach 43,400 GWh, a 40% increase from the previous forecast, with a compound annual growth rate of 5.3%. Much of the growth will be concentrated in the northern part of the state.

"The main reason for the difference is a continued increase in the large customer requests, specifically data centers and AI-driven load," Wells said.

As for the RPS, existing and approved renewable resources will be enough to meet the standard in 2027, NV Energy's projections show. But more renewables will be needed starting in 2028 for RPS compliance.

To help meet its surging demand, NV Energy issued a request for proposals in 2024. The RFP drew 198 bids — a company record.

From there, the company developed a shortlist of 15 projects totaling 8 GW of capacity. About 3,800 MW is new generation and about 4,200 MW is storage, Wells said. NV Energy has already requested regulatory approval for one project: a 150-MW power purchase agreement for the Dodge Flat battery storage system in northern Nevada.

Approval for other projects will be sought through the 2026 IRP. Wells said the expected ratio of renewables and storage to thermal resources is roughly 3:1. She noted that the earliest new gas combustion turbines could be in operation would be 2029 or 2030.

Allocating Costs

NV Energy's base load forecast for its 2026 IRP includes "mitigation" for large loads — meaning requested loads are reduced by half if a line-extension contract has been signed or by 85% if there's no contract, Wells said during the December meeting.

In addition, the company developed a "base minus" forecast that excludes growth from data centers and AI. Wells said resource costs to meet the two forecasts would be compared, and the extra costs seen in the base forecast could then be allocated to large load customers.

A third forecast called "base plus" assumes that all load will materialize from large customer projects with signed contracts.

In another consequence of surging demand, NV Energy is delaying plans to close its open position, which refers to resource needs that are met through short-term market purchases rather than by the utility's own resources or long-term contracts.

Wells said the goal now is to gradually reduce the company's open position from around 2,000 MW in 2027 to 500 MW by 2031.

NV Energy is required to file an IRP at least every three years. Legislation passed in 2023 authorized the company to file an IRP more often "if necessary." The 2026 IRP is coming only two years after the company's 2024 plan.

NV Energy plans to host a third stakeholder session on the 2026 IRP in February, with a focus on the company's distributed resource plan, the transportation electrification plan and the demand-side management plan.

A consumer session is also planned. ■

FERC Staff Recommends Relicensing of Idaho Power's Hells Canyon Dams

Agency Staff Issues Draft SEIS for Dam Complex on Snake River

By Henrik Nilsson

Why This Matters

With the draft SEIS, Idaho Power reaches an important milestone in securing a license for the three dams.

FERC staff said the commission should relicense three Idaho Power-owned hydroelectric dams that have been operating under annual licenses since 2005, finding the company's proposed measures, along with staff recommendations, adequately mitigate the environmental impact of the dams.

Commission staff on Jan. 14 issued a draft supplemental environmental impact statement (SEIS) after Idaho Power filed proposed modifications for the 1,222.3-MW Brownlee, Oxbow and Hells Canyon dams, collectively the Hells Canyon Project.

The dams are located along the Snake River in Idaho and Oregon, and occupy about 5,270 acres of federal land, according to the draft SEIS.

"We are pleased to have reached this milestone in the relicensing process for the Hells Canyon Complex, which is an essential part of Idaho Power's resource portfolio," Idaho Power spokesman Brad Bowlin told *RTO Insider*.

The company will provide detailed answers to FERC by March 2, which is the deadline to submit public comment on the draft SEIS.

Idaho Power applied for a new license in 2003 to operate the Hells Canyon Project. The company has operated the dams under annual licenses since the current one expired in 2005, the SEIS states.

Idaho Power's Brownlee Dam is the largest and furthest upstream of the three dams in the company's Hells Canyon Project along the Snake River. | *Idaho Power*

FERC issued the final environmental impact statement for Hells Canyon in 2007, but following several new developments, including settlements with key stakeholders, FERC prepared a supplemental environmental review to account for these changes.

Among the recent developments is a 2019 settlement between the company and Oregon and Idaho that resolved disputes over water quality and protections of Chinook salmon and steelhead. Following the settlement, Oregon and Idaho issued 401 certifications for Hells Canyon under the Clean Water Act.

In 2020, Idaho Power filed a supplement to its license application that included new environmental measures proposed under the 2019 settlement.

In 2022, FERC issued a notice of intent to prepare a final SEIS to address the new measures. Following the notice, Idaho Power filed a settlement agreement with the U.S. Forest Service in 2024 related to the company's use of federal land.

In the Jan. 14 draft SEIS, FERC staff wrote the main concerns with relicensing are the effects on sediment supply and transport, water quantity and quality, aquatic resources, terrestrial and cultural resources, and the adequacy of recreational facilities to meet expected demand over the term of any new license.

FERC staff recommended relicensing the project under most of Idaho Power's proposed measures and "certain mandatory conditions and recommendations made by state and federal agencies and some staff-recommended modifications to further minimize project-related effects on aquatic and terrestrial resources, threatened and endangered species, recreation resources, and cultural resources," a news release stated.

Hells Canyon Dam | *Idaho Power*

The approach recommended by staff includes all conditions in the 401 certifications issued by Oregon and Idaho except for three: implementation of three phosphorus load-reduction programs, implementation of a program that consists of completing habitat restoration projects in the Snake River Basin upstream of the project and implementation of a mercury and methylmercury study.

"Because there is no project nexus associated with these conditions, staff concluded that there would be no project-related benefit to implementing these measures and does not include them in the staff alternative," the draft SEIS states.

The draft SEIS estimates power generated by Hells Canyon under the staff-recommended approach could "cost $120,748,800, or $21.67/MWh, less than the likely alternative cost of power."

"We chose the staff alternative as the preferred alternative because: (1) the project would continue to provide a dependable source of electrical energy for the region (5,571,005 MWh annually); (2) the public benefits of the staff alternative would exceed those of the no-action alternative; and (3) the proposed and recommended environmental measures would protect and enhance environmental resources affected by the project," the draft SEIS states. "The overall benefits of the staff alternative would be worth the cost of the proposed and recommended environmental measures." ■

CPUC OKs New Tx Projects for Microsoft Data Center Despite Cost Unknowns

Commission also Approves 225-MW PG&E Battery Storage Reliability Project

By David Krause

Microsoft

The California Public Utility Commission approved a set of transmission infrastructure projects to support a 90-MW data center owned by Microsoft, but questions remain about whether the upgrades will increase or decrease ratepayer costs.

The transmission projects present "unique considerations" not fully addressed by certain existing electric rules, the CPUC said in a *resolution* approved at its Jan. 15 voting meeting. The resolution is based on *advice letter 7635-E*, which was submitted by Pacific Gas and Electric (PG&E) in July 2025.

The electric rules in question normally apply to distribution energization projects, but Microsoft's data center is expected to have a 90-MW load — a "significant" amount that will require a new 115-kV transmission line and substation upgrades, the resolution says.

"Because the Microsoft project will be interconnected at the transmission level, Microsoft will pay lower electric rates than an equivalent large load customer that is connected at the distribution level and normally covered by the Rule 15 process, while at the same time potentially contributing to the need for broader transmission network upgrades in the region," the commission said in the resolution.

Providing electricity to the new data center requires "significant costs but comes with the opportunity for significant revenue received by PG&E," the resolution says.

If these revenues are large and consistent, other customers might need to pay less of PG&E's overall revenue requirement, which could lower rates for PG&E customers, the resolution says. But if the revenues are small or are not received consistently, PG&E customer rates could increase, it says.

PG&E will complete the following work for Microsoft's data center:

- transmission upgrades at PG&E's Los Esteros substation
- a new 115-kV transmission line from PG&E's Los Esteros substation to Microsoft's Kaku substation
- a design review of Microsoft's Kaku 115-kV substation
- an additional 115-kV transmission line from PG&E's Los Esteros substation to Microsoft's Kaku substation

PG&E could not determine which transmission facilities CAISO will control, according to the resolution.

The data center will operate at a continuous 90-MW load for 24 hours a day, 365 days a year, the resolution says.

Microsoft has also requested a second 115-kV line to provide redundant service; however, this project falls under a special facilities agreement and will not be paid by PG&E ratepayers at any point, the resolution says.

Microsoft also plans to install two natural gas-fired generators for critical load and emergency backup, the advice letter says.

Why This Matters

The CPUC's resolution to approve transmission projects to serve a Microsoft data center points to the risks that ratepayers face in potentially footing the costs for infrastructure to support large loads.

Dirac BESS Approved

At the meeting, the CPUC *approved* also a 225-MW lithium-ion battery storage project for PG&E. The storage facility will provide resource adequacy capacity and has a planned online date of May 20, 2028, with a 15-year energy delivery commitment.

The storage facility's capacity will replace Diablo Canyon Power Plant's capacity when, and if, the nuclear plant is retired. The facility, called the Dirac Battery Energy Storage System, will be built by Aypa Power Development using the company's subsidiary, Balsam Project. ■

BPA Prepares Pilot Program to Reduce Balancing Reserves

Batteries, Nuclear and Wave Energy Among Possible Resource Types

By David Krause

The Bonneville Power Administration is starting a new pilot program to decrease the balancing reserve capacity it must hold to account for variable resources by connecting new types of generation facilities to its grid.

As part of the New Generation Technology Pilot, BPA will work with generators to "encourage development of technologies and operations" that reduce balancing reserve capacity requirements in the agency's balancing authority area, BPA staff said at a Jan. 13 workshop to explain the program.

A *presentation* from the workshop outlined three objectives for the pilot:

- incentivizing "accurate scheduling and performance";
- establishing a "technology inclusive policy" for participation; and
- fostering collaboration between BPA and generators "to enable novel approaches to lower the amount of capacity needed" to integrate variable generation.

Participating resources could include nuclear power plants or wave energy structures, BPA electric engineer Ross Ponder said during the workshop.

A proposed project will need to meet performance metrics, which will be established based on historical balancing reserve capacity usage and projections, Ponder said. Participation in the pilot will rely on a reduction in station control error (SCE), and BPA will revise a project's performance expectations if the project increases its SCE, Ponder said.

The pilot program "essentially can be … used to provide a method to reduce generators' balancing reserves capacity," Ponder said.

Battery energy storage systems (BESS) and nuclear facilities are two possible resource types eligible for the pilot, Bart McManus, a BPA engineer, said at the workshop.

However, "we are not saying [a project] has to be BESS or nuke," McManus added. "We are looking for innovative strategies. We don't run solar plants. We don't run nuke plants. So if you have something that could work, absolutely bring it to the table and we will talk through it."

One meeting participant asked about the current performance and buildout of co-located generation and battery storage in BPA's region.

| © RTO Insider

Why This Matters

BPA's technology pilot program will try to reduce balancing capacity requirements for both generators and the BPA balancing authority area at large. Doing so should lower system costs, among other outcomes.

"We don't really have a lot of examples of co-located generation," BPA engineer Nancy Morales said. "So the status quo is there is minimal impact of co-located resources."

A meeting participant also said that the pilot has "technically been around for a while, but the last I heard about it … is that nobody had taken Bonneville up on the offer to participate in it."

"When did this pilot begin and has anyone taken you up on it yet?" the participant added. "Is there anything that is different about it now?"

"We have a few requests to join the [pilot]," Ponder said. "We are currently in the design phase … but we don't have anyone active yet."

Ponder added that he expected to hold a few more meetings later in 2026 to discuss the pilot and respond to future questions.

When a generator or load connects to BPA's grid, BPA must provide balancing reserves at a rate and amount determined by the agency for reliability purposes. BPA can provide balancing reserve capacity to cover a 99.7% planning standard for balancing error events without unreasonably impairing reliability, the agency said in a September 2025 *document*. ■

Conditional Firm Service Offers Way out of BPA's 61-GW Queue, City Light Says

Proposal Discussed During Jan. 15 GAT Project Meeting

By Henrik Nilsson

Seattle City Light presented its proposal for the Bonneville Power Administration's overhaul of the agency's transmission planning process, saying BPA should offer interim conditional firm service (CFS) to most developers in the 61-GW transmission service queue.

During a Jan. 15 customer-led meeting, SCL's Michael Watkins said the municipal utility supports many of the proposed alternatives under BPA's Grid Access Transformation (GAT) project, including moving toward proactive transmission planning, "so that you're planning ahead of customer needs, not responding to customer requests."

BPA has a goal of reducing the time from transmission request to service to five to six years.

Watkins said SCL supports that goal and "Bonneville acquiring the resources to be able to do that."

"We believe that future makes sense if customers can access conditional firm service/non-firm service, in the very near to short time, so that customers can react nimbly to a very changing landscape with some conditional firm service to get transmission service to meet those needs," Watkins said.

BPA launched the GAT initiative to consider changes to its planning processes following a surge of transmission service requests (TSRs). The most recent transmission study includes 61 GW of new generation, compared with 5.9 GW in 2021, according to the agency. (See *BPA Tx Planning Overhaul Prompts Concern for Northwest Clean Energy Compliance*.)

BPA's proposal to tackle the queue involves a two-part approach: a transitional phase to get off the pause and a longer-term "future state" that will include more substantial reforms to BPA's existing transmission processes, such as shifting toward proactive transmission planning or stricter evaluation criteria of TSRs to reduce the queue.

City of Seattle

But even with the "myriad" of options BPA has presented, the queue will remain around 31 GW, which will take about five to seven years to study, *according to SCL's presentation slides*.

"We just don't see that as a real solution for the region," Watkins said.

BPA staff noted during the meeting that the agency does not have a proposal, only alternatives for stakeholders to consider, saying "it's entirely possible … under the strictest application of new evaluation criteria, that the queue would be significantly smaller than the 31 GW that's on the slide."

"So, again, not a proposal, but just there are some options that would get us to a significantly smaller queue," BPA staff said.

'Daring and Bold'

Still, BPA should offer interim CFS with few exceptions to address the queue, Watkins argued. CFS is a form of long-term firm transmission service that allows BPA to curtail the reservation under certain circumstances, *according to BPA documents*.

"I believe where we're at as a region has led us to a place where our best option is to now operate by curtailment," Watkins said. "And in 99.9% of the time of the hours of the Northwest, there is never curtailment, even though there's almost unlimited non-firm every one of those hours. I believe in the short term … we could live with … curtailment, with almost unlimited conditional firm service on our system, with the caveat that when we're in extreme weather events it's not going to work."

To secure CFS, customers would, for example, sign contracts with additional requirements, such as length of contract, securitizing future and unknown projects, and securitizing five years of service rates.

> **Notable Quote**
>
> "We believe that future makes sense if customers can access conditional firm service/non-firm service, in the very near to short time, so that customers can react nimbly to a very changing landscape with some conditional firm service to get transmission service to meet those needs,"
>
> *— Michael Watkins, Seattle City Light.*

"We think if we go down that route, that most of the queue will self-select to get out of the queue," Watkins said. "Therefore, you don't need a lot of large policy levers pulled to filter out the queue with. And that lends itself to queue management."

BPA staff called the idea "daring and bold," noting that the proposal has been up for discussion in the past.

Staff appeared to acknowledge the potential of offering CFS as a way to clear the queue by requiring financial commitments. Still, they warned that if more customers than expected accept the offer, it could put the agency and the region in a tricky spot.

"If we are surprised by the number that accept the offers, the amount of work in front of us to catch up on the sub grid might be more than we could handle, and so we may have gotten ourselves then into a reliability issue that we can't build our way fast enough out of," staff said. "And so it's just hard to say exactly how much risk we would be exposed to collectively. That's not Bonneville's risk. That would be all of our risk." ■

IESO Reliability Compliance Plan Focuses on CIP, Modeling, IBRs

By Rich Heidorn Jr.

IESO is targeting six areas of NERC's reliability standards in its 2026 compliance program, largely continuing a focus on issues it has prioritized since 2023.

The 2026 Market Assessment and Compliance Division (MACD) Reliability Standards *Compliance Monitoring Plan* will prioritize:

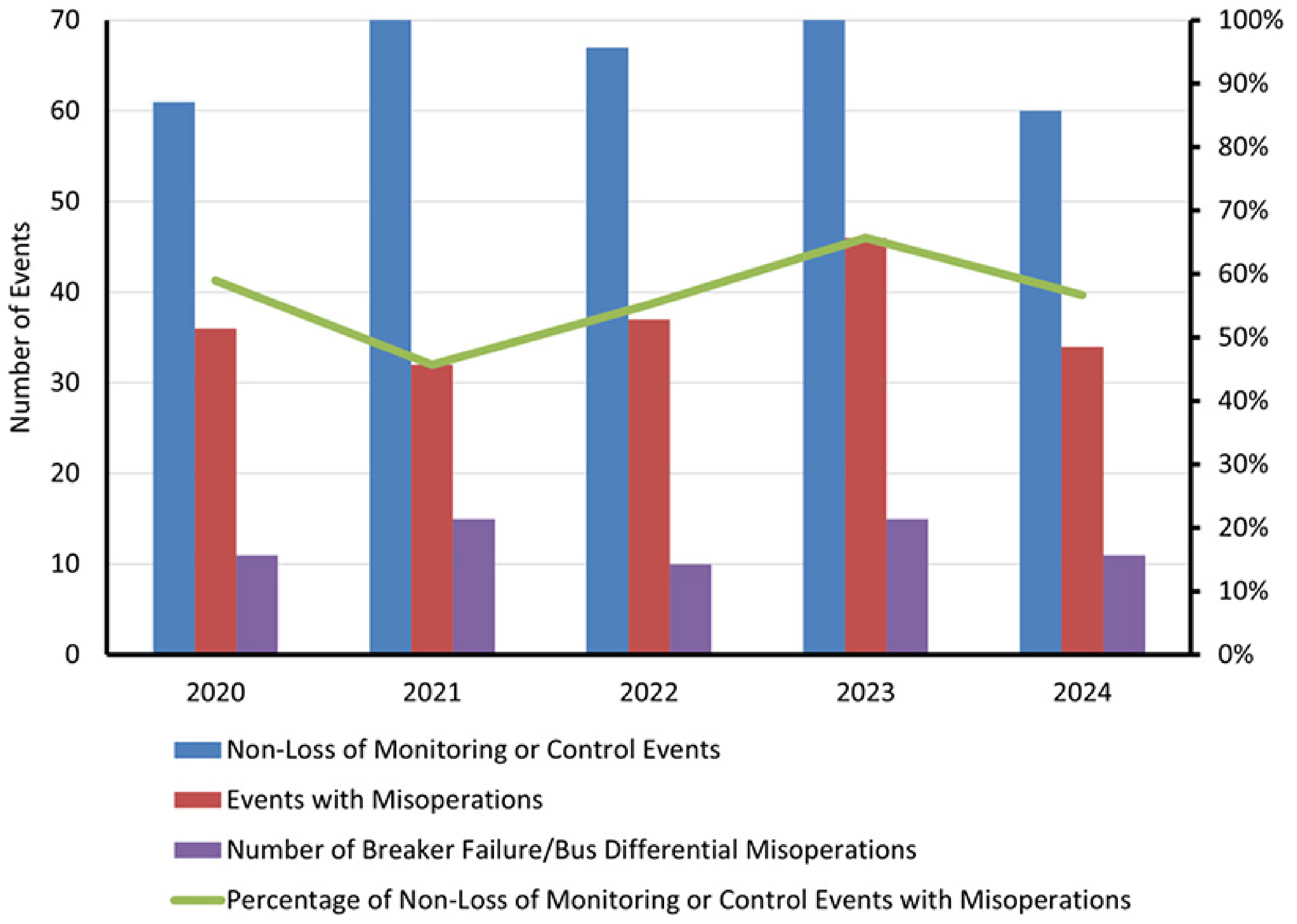
- Critical Infrastructure Protection (CIP)
- Inadequate Models Impacting Planning and Operations (MOD/PRC)
- Gaps in Program Execution (FAC)
- Automatic Underfrequency Load Shedding (PRC)
- Inverter-Based Resources (PRC), and
- Extreme Weather Response (EOP)

MACD says its priorities consider the reliability standards' applicability to Ontario; the assessed reliability risks and compliance history of each standard; power system infrastructure and demand changes; and emerging threats and vulnerabilities.

"While market participants are required to comply with and be able to demonstrate compliance with all applicable reliability standards at all times, MACD puts a more significant focus on a subset of these market rules and reliability standards that are more explicitly monitored for compliance in a given year," IESO said.

Why This Matters

IESO's Market Assessment and Compliance Division says its priorities consider applicability of reliability standards to Ontario.



NERC reported 60 transmission-related events in 2024, 34 of which (57%) involved protection system misoperations, a drop from 2023 with 70 transmission-related events, of which 46 (66%) involved misoperations. NERC said the reduction likely resulted from task forces, workshops and analytical efforts to reduce misoperations. | *NERC*

The MACD conducts scheduled and unscheduled audits, in addition to accepting self-reports and self-certifications.

MACD selects the subject of scheduled audits based on "both market participant specific information and Ontario-specific risks." Subjects are provided at least 90 days' notice before the start of scheduled audits. MACD also may conduct unscheduled audits "potentially with very little or no notice," it said.

NERC Concerns

In its *2025 State of Reliability Report*, NERC said key performance metrics such as frequency response and misoperation rates continued to improve or remain stable.

It said weather continued to be responsible for the most severe outages in 2024, citing two significant winter storms and five major hurricanes. It noted an improvement in winter performance, with no operator-initiated load sheds, in part due to efforts to improve generator performance during extreme cold.

The report says large data centers pose a "significant near-term reliability challenge" because they are growing faster than generation and transmission infrastructure. It said more accurate models of data centers' operational characteristics are needed because of their "voltage sensitivity and rapidly changing, often unpredictable, power usage."

NERC also noted improvements in frequency response in regions with high concentrations of battery energy storage systems, but said some inverter-based resources "continue to unexpectedly reduce output following disturbances that generators have historically been expected to ride through."

MACD Findings

MACD's *Sanctions* and *Negotiated Settlements* notices include violations of market rules, as well as several cases involving NERC and Northeast Power Coordinating Council reliability standards.

In 2022, IESO reached a $1.67 million settlement with Ontario Power Generation and a $1 million agreement with Hydro One Networks for failing to properly plan a maintenance outage at the Darlington Nuclear Generating Station. IESO alleged that OPG and Hydro One failed to recognize the purpose and limits of electrical protective relay schemes. In one instance, equipment at the Bowmanville Switching Station operated without this scheme for approximately five months without incident, which IESO concluded "gave rise to a significant market and electrical reliability concern with a low probability of occurrence."

In 2023, it reached a $327,000 settlement with Kirkland Lake Power Corp. and a $12,500 agreement with Iroquois Falls Power Corp. IESO said Kirkland Lake failed to maintain evidence that it maintained its equipment as required and, in another event, incorrectly adjusted the underfrequency trip settings on certain electromechanical relays. Iroquois Falls lacked evidence that it conducted the required annual vegetation inspection of a transmission line in 2018.

GenSet Resource Management agreed in 2023 to pay $500,000 for its failure to comply with dispatch instructions for operating reserves between 2013 and 2019, which IESO said posed a reliability risk. ■

ISO-NE Details Inputs for Capacity Auction Reform Impact Analysis

By Jon Lamson

ISO-NE *outlined* its methodology for analyzing potential effects of its capacity auction reform (CAR) project at the NEPOOL Markets Committee meeting Jan. 14, detailing resource mix and load inputs for the near- and longer-term base cases and potential factors to be considered in sensitivity analyses.

The RTO plans to present the initial results of the impact analysis starting in March and will work with stakeholders to develop sensitivities building on the two base cases.

"This analysis will provide stakeholders with a better understanding of how CAR may impact how much capacity they can sell, and wholesale market revenues and costs under specific scenarios, as well as other key parameters," said Chris Geissler, director of economic analysis at ISO-NE.

The near-term base case "seeks to use assumptions that are broadly in line with expected system conditions for CCP [capacity commitment period] 19," said Fei Zeng, manager of planning services at ISO-NE.

CCP 19 will procure capacity for the 2028/29 commitment period; ISO-NE aims to implement both phases of the CAR project for this period. The first phase of CAR, filed with FERC at the end of 2025, centers around implementing a prompt capacity auction and resource deactivation reforms. The second phase centers around resource capacity accreditation and the development of seasonal capacity commitment periods. (See *NEPOOL Supports First Phase of ISO-NE Capacity Market Reform*.)

Why This Matters

The long-awaited impact analysis for ISO-NE's capacity auction reform project will provide indications about auction costs and resource revenues, while sensitivity analyses will quantify the effects of resource and supply mix changes.

The Bucksport Power Station in Hancock, Maine | *JERA*

The RTO plans to rely on resource mix modeling assumptions from the most recent annual reconfiguration auction, adjusting the mix based on planned deactivations, under-development resources that have withdrawn from critical path schedule monitoring and resources that qualified in the 2025 interim qualification process. The resource mix assumptions result in about 37,500 MW of non-intermittent qualified capacity and about 2,000 MW of intermittent qualified capacity.

To estimate demand, ISO-NE will use the 2028/29 load forecast from its 2025 capacity, energy, loads and transmission (CELT) report.

For the longer-term modeling base case, ISO-NE plans to use the 2025 CELT demand forecast for 2035. The RTO plans to approximate the resource mix for 2035 by adding 2,000 MW of offshore wind, 200 MW of utility solar and 200 MW of two-hour batteries. These resource additions "may be aligned with a conservative approximation on progress toward the states' public policy by this time frame" and are meant to serve as a "starting point to build from," Geissler said.

Some stakeholders expressed concern that the longer-term base case includes too little storage at too short of a duration. In response, ISO-NE emphasized that conservative assumptions should help provide a good point of comparison for subsequent sensitivity analyses evaluating increased levels of storage and renewable penetration.

For both base cases, the impact analysis will provide information on estimated effects on the net installed capacity requirement, marginal reliability impact demand curves, and seasonal relative MRI values and MRI capacity by resource type, he said.

ISO-NE previously presented initial impact analysis results associated with its resource capacity accreditation project, which the RTO incorporated into the broader CAR project in 2024. These results indicated significant capacity revenue boosts for imports, energy efficiency, non-intermittent hydropower, dual-fuel generators and nuclear plants, along with revenue declines for energy storage, oil-only resources, hybrid resources and active demand response. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.)

Building on the base case modeling, ISO-NE plans to run sensitivity analyses based on stakeholder recommendations. Potential sensitivities could alter factors related to heating and transportation electrification, behind-the-meter generation, renewable and storage development, and retirements of oil-fired generators.

Because ISO-NE's proposed MRI accreditation approach is intended to compensate resources for their reliability contributions during the hours with greatest shortfall risk, changes to the load profile or resource mix could significantly affect resource accreditation by shifting when these hours occur.

One stakeholder expressed concern that the 2025 CELT report does not include large loads expected to come online and urged the RTO to consider running a sensitivity analysis that considers the effects of this potential demand. ISO-NE indicated this may be challenging due to the lack of "well-established evaluation frameworks."

ISO-NE plans to give a follow-up presentation on the impact analysis in February and has requested stakeholder feedback on its proposed approach.

Gas Capacity Demand Curve

Also at the Markets Committee meeting, ISO-NE continued discussion on its proposal for a new gas capacity demand curve intended to account for generators' limited access to pipeline gas during cold-weather periods. (See *ISO-NE Talks CAR Gas Constraints, Seasonal Risk Split, Impact Analysis*.)

The current rules, which do not account for the region's gas constraint, create a "money for nothing problem" by fully accrediting gas-only resources that may not be able to run when pipeline access is limited, said Steven Otto, manager of economic analysis at ISO-NE.

While ISO-NE initially proposed to account for gas constraints within the accreditation process, it has shifted its approach due to concerns about how gas would be allocated to different resources. Under the current accreditation proposal, the RTO would model gas-only resources without fuel limits.

"When gas availability is constrained, the inclusion of the gas capacity demand curve in the winter capacity market would affect the quantity of gas capacity procured and its settlement price in the same way that an export-constrained capacity zone demand curve affects the procurement and settlement price of export-constrained capacity zone capacity," the RTO noted in a Jan. 7 *memo*.

Otto said the changes are essential for sending accurate market signals, procuring the most cost-effective mix of capacity, and preventing reliability issues associated with relying on gas capacity that is unable to perform during cold weather. The proposal likely would provide an incentive for gas resources to enter firm fuel arrangements that would exempt the resources from the gas capacity demand curve.

Intermittent Resource Accreditation

ISO-NE also discussed its proposed approach to accrediting intermittent resources. It plans to use hourly profiles for all intermittent resources; it would construct hourly wind and solar profiles based on resource characteristics and historical weather patterns; and it would construct profiles for run-of-river hydropower, landfill gas, municipal solid waste, wood and biogas generation based on historical output data.

The RTO plans to model all non-settlement-only intermittent resources on an individual basis and model settlement-only intermittent resources on an aggregated basis, "grouped by load zone and IPR type," said Hannah Johlas of ISO-NE. This aggregation would apply only to solar and intermittent hydro resources, and the RTO would not rely on aggregates for groups made up of fewer than 10 resources, Johlas added.

ISO-NE plans to continue discussions on intermittent resource modeling and accreditation at the Markets Committee meeting in February. ■

MISO Preliminary Auction Data Shows Added Load in 2026/27

By Amanda Durish Cook

MISO is registering and accrediting resources to meet a roughly 2-GW uptick in load for the 2026/27 planning year.

The grid operator has so far *recorded* a preliminary 135.6 GW in total accredited capacity for the peak summer season, and it still has some resource registrations in progress.

The RTO reports it has nearly 175.6 GW of total installed capacity. For the 2025/26 planning year, the RTO had 139.4 GW in accredited capacity available to it in summer.

MISO has established an initial 137.5-GW initial planning reserve margin requirement to cover a 124.7-GW coincident peak forecast for summer. The RTO's downward-sloping demand curve used in the auction will likely clear more capacity than the margin requirement. It entered the 2025/26 auction with a 135.2-GW margin requirement and ended with a nearly 137.6-GW requirement. Its 2025/26 coincident peak load forecast was 122.6 GW.

Speaking at a Jan. 14 Resource Adequacy Subcommittee meeting, MISO Manager of Resource Adequacy Andy Taylor said load forecasts have risen across the board for the upcoming planning year, according to load-serving entities. He said the increases aren't large enough to cause panic.

The grid operator's numbers, prepared for the upcoming spring capacity auction, are preliminary. MISO plans to post five more data updates through March 19.

MISO will open its capacity auction offer window March 26-31 and post auction results April 28.

MISO's 2026/27 planning year will begin June 1. ■

Work on We Energies and Wisconsin Public Service's Weston RICE generating station in 2022 | *Burns and McDonnell*

MISO to End Market Platform Project in 2026, Leave Major Real-time Market Work Unfinished

By Amanda Durish Cook

Why This Matters

It's curtains for MISO's nearly decade-old market platform replacement project. The abrupt conclusion leaves MISO's new unit dispatch system incomplete and relegated into a standalone project.

After nine years, MISO will close out its multiphase market platform replacement project, leaving a bulk of unfinished work on its real-time market.

MISO said it's "adjusting the remaining scope to conclude the program in 2026," and will cut its work to build a new unit dispatch system from the multiyear effort. That undertaking will become a standalone project.

MISO's unit dispatch system balances generation and load in five-minute intervals to clear the real-time market, selecting generators' offered megawatts and prices while managing transmission congestion and meeting reserve requirements. The system sends five-minute dispatch and price signals to generators based on bids and system need.

MISO's removal of a new unit dispatch system from the market platform project means that the RTO will spend an estimated $154 million on the market platform swap-out, not including the unit dispatch system. MISO began the platform project with a $130 million budget plus a 25% contingency, bringing the total spending limit to $162.5 million.

MISO said even though it's cutting out the capstone task of the platform replacement project, the work thus far on the project would deliver about $425 million in benefits.

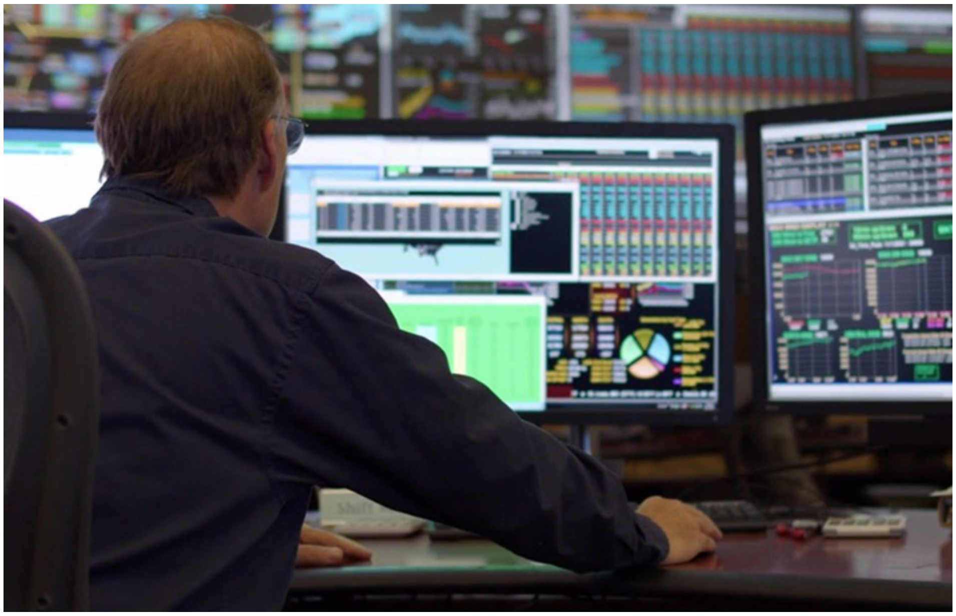
"Obviously, we've spent more than we anticipated," MISO's Scott Daugherty said during a Jan. 15 meeting of the Market Subcommittee. Daugherty added the expense is part of MISO being on the "cutting edge" of incorporating the newest technologies.

The RTO said it was experiencing difficulties completing work on the real-time market clearing engine in late 2025. At the time, it *predicted* that building a new unit dispatch system would cost about $20 million and take until 2028. (See *MISO: Market Platform Replacement will be Overbudget, Stretch into 2028*.)

MISO planned to build the unit dispatch system over 2026, test and deliver it sometime in 2027 and formally launch it in 2028. It's unclear what a new budget and timeline might be. In the meantime, MISO will make do with its existing system.

MISO principal adviser Kevin Larson said re-platforming MISO's market has been a complex endeavor.

"We originally hoped to be done with this in the late 2024/2025 timeline," Larson said. (See *MISO Sets Sights on 2025 Completion for New Market Platform*.)



MISO control room | *MISO*

Daugherty said isolating the unit dispatch system overhaul as its own project will allow MISO to work more automation into the finished product.

"Eventually we'll get the UDS to the current re-platformed engines," he said.

"The core objective we were going after is performance and security," Larson added.

In response to stakeholders' questions, Larson said the new market platform won't be embedded with AI-based technology. Larson said AI would show up in the market's "secondary capabilities," like MISO's uncertainty management tool, which helps guide dispatch.

Some stakeholders said they were disappointed with MISO's decision to strike the dispatch system rebuild.

"I'm trying to be calm; I am frustrated with this, but I understand this is difficult to do," Fresh Energy's Mike Schowalter said.

Schowalter said MISO has told stakeholders repeatedly the market platform replacement would allow MISO to make more complex market changes. He asked to what extent "carving out" the unit dispatch system would impede what's possible.

Schowalter said the new market platform always has seemed like "black box that's going to do all these magic things" that stakeholders might not understand. He asked for a more detailed explanation of what new capabilities the market platform would enable.

Kevin Larson (left) and Scott Daugherty, MISO | *MISO*

"What are those things that are going to have to wait another two years?" Schowalter asked. He added there's "a lack of understanding on what's waiting for what."

Daugherty said the purpose of the market platform replacement is to "not do much that's new but re-platform the existing capabilities" and position the markets to be more adaptable to new technologies and increasingly complex market products.

"We've had this big chunk of market enhancements we haven't been able to go after," Daugherty said.

Clean Grid Alliance's David Sapper asked where MISO's work to bring aggregated distributed energy resources into the market under FERC Order 2222 stood.

MISO staff took down the question to address later.

Michigan Public Power Agency's Tom Weeks said the market platform replacement was sold by MISO as: "OK, all the things we can't do in terms of improving the markets, we can do" once the new platform is in place. Weeks made the comment while *asking* MISO to create a commitment process especially for jointly owned generation resources.

MISO said the remaining sections of in-progress market platform work are positioned to be completed at the end of 2026. That includes the launch of its reliability assessment and commitment market tool, its look-ahead commitment tool and its one-stop repository for planning and operations data to create its models.

MISO unveiled its new day-ahead market clearing engine as part of the project in 2024.

Larson said MISO began the platform project in 2017 when it began having "on and off problems" with its day-ahead market clearing engine. At that time, it had a wish list of improvements the aging market platform wouldn't be able to handle.

MISO needs pieces of the market platform replacement, specifically the new look-ahead commitment tool, to be able to comply with FERC's Order 881, which requires real-time ambient-adjusted line ratings.

The look-ahead commitment tool works with the unit dispatch system to arrange near-term generator commitments.

Order 881 by 2028

MISO said it doesn't expect full compliance with Order 881 until the end of 2028, due in part to the delay of the new look-ahead commitment clearing engine. (See *MISO to Seek 3-Year Order 881 Delay for Vendor Holdups*.)

At a Jan. 13 Reliability Subcommittee meeting, MISO also said its vendor might not be able to deliver the necessary software as scheduled in the second half of 2026 to ready its real-time system to incorporate the varied ratings. MISO added that its transmission owners are expected to prepare for the new rule into 2027.

"MISO's systems being ready doesn't mean that TO systems are ready," MISO's Paul Kasper said. He reminded stakeholders that TOs must conduct their own system testing and integration campaigns.

Kasper said MISO is taking "exceptional" steps to maintain its timeline on the project. "There's only so much we can control with the vendor." ■

Earthjustice Says Change to Louisiana Meta Data Center Funding Fishy, Asks PSC to Investigate

By Amanda Durish Cook

Earthjustice accused Meta of deliberately executing an unsanctioned financial arrangement to underwrite its planned, multibillion-dollar data center in northern Louisiana and asked the Louisiana Public Service Commission to investigate.

Representing the Alliance for Affordable Energy and the Union of Concerned Scientists, Earthjustice said it appeared Meta had ulterior motives for the financial risk it was willing to undertake for the data center.

Meta did not reply to a request for comment on the allegations.

In a Jan. 14 *motion* for investigation to the Louisiana PSC, the environmental law center said "immediately after" the commission approved Entergy Louisiana's application for three new gas plants to power the data center in August 2025, Meta "fundamentally altered" the financing structure of the project.

The Bottom Line

Following a change in financing structure to Meta's massive Hyperion data center plans in Louisiana, Earthjustice has asked the Public Service Commission to investigate whether electric ratepayer protections remain undisturbed. The Meta data center requires Entergy Louisiana to build three natural gas plants.

Blue Owl, Beignet, Laidley

Enter asset management firm Blue Owl Capital. In late summer, it and Meta created the joint venture Beignet Investor, which now reportedly owns an 80% stake in the data center. Meta owns the remaining 20%. Beignet acquired Meta company Laidley to secure the majority ownership. (Stay with us here.)

When the Louisiana PSC approved Entergy's power supply proposal for the data center, Meta used Laidley, its development affiliate, to represent itself. Laidley is the sole signatory to the data center's energy service agreement with Entergy Louisiana for the three natural gas plants. Earthjustice noted that Beignet Investor registered as a limited liability company in Delaware on Aug. 20, 2025, the same day the Louisiana PSC voted 4-1 to approve Entergy's supply contracts (U-37425). (See *Louisiana PSC Approves 3 Controversial Gas Plants Ahead of Schedule for Meta Data Center*.)

Now, Meta would pay rent to Beignet to use the Meta Hyperion data center, with the option to exit the lease every four years. Should Meta decide to depart, Beignet would sell the center to pay outstanding bonds and then pay itself, Earthjustice told the Louisiana PSC. If sale proceeds fall short of what's owed to bondholders combined with Blue Owl's investment, then Meta would pay the difference. Meta would guarantee its rent and payment obligations via parent guaranty to Blue Owl.

Earthjustice said because Meta already has significant debt load, Blue Owl invested $3 billion for an 80% stake in the Hyperion data center. Meta's existing $1.3 billion investment earned it the remaining 20%.

Beignet then borrowed $27 billion for the project. The new LLC has no assets beyond the data center; Earthjustice said that makes it a "riskier partner as the guarantor" of the supply arrangement with Entergy.

Meta's rent payments would go to bond interest and principal payments, as well as dividends for Blue Owl.

The joint venture between Meta and Blue Owl is the largest private credit transaction ever and allowed Meta to receive a $3 billion cash distribution from the venture upon closing.

The convoluted arrangement was referred to as "Frankenstein financing" by *The Wall Street Journal*, which published a Nov. 11 investigative piece on the labyrinthine financing Big Tech uses to break ground on data centers.

'A Secret'

Earthjustice said the "remarkable," same-day creation of Beignet "illustrates that Meta and Blue Owl were working behind the scenes to significantly alter the financial structure of the data center project while the proceeding to examine the now irrelevant data center financial structure was ongoing."

"Meta kept this significant change a secret, just like Meta kept how they developed their load forecast and how they determined their job numbers a secret," Earthjustice claimed, adding that the PSC needs to know the facts behind the funding of the data center.

Earthjustice said if the AI boom were to dry up, Meta could walk away from the deal as soon as 2033. It said by then, the data center could lose prospects for another buyer and depreciate.

Meta, Entergy and the Louisiana PSC expect construction on the data center campus to continue through 2030.

"This novel financial arrangement lets Meta add computing power quickly and then wait to see how demand for AI shapes up before fully committing to projects that can last for decades. Thus, Meta is off-loading its own risk by placing that financial risk on others, including ratepayers who will be on the hook for all the infrastructure built solely for this data center should Meta exercise its option to walk away," Earthjustice argued. The law organization said all the ratepayer protections the Louisiana PSC hammered out in its approval are "at best, called into question" because Meta no longer is Laidley's parent company.

Throughout the PSC's consideration of the gas plants to power the data center, the Alliance for Affordable Energy and the Union of Concerned Scientists voiced concern of the risk of after-the-fact changes to the electric service agreement with Entergy, the risk of stranded costs or capital cost overruns on the gas plants and an "inappropriately short" 15-year contract term on the power supplied by Entergy.

"This new, novel financial arrangement, which very likely was withheld from the commission prior to its action on [Entergy Louisiana's] application, calls into question the meager ratepayer protections included in the application and contested settlement agreement and undermines the assumptions made by the commission when it voted to approve the application," Earthjustice wrote.

The Louisiana PSC approved consumer protections including a provision that Meta's minimum bill payments would cover 100% of the costs of the trio of generating units, including cost overruns. Meta also agreed to fund development of 1.5 GW of solar generation under the state's Geaux Zero program and to provide up to $1 million per year for Entergy's Power to Care, which is a bill assistance program for low-income, elderly and disabled Entergy Louisiana customers.

Entergy has entered the first of three gas plants into MISO's expedited interconnection queue and submitted the 500-kV facilities needed to connect the data center into MISO's expedited transmission approval process.

At publication time, Meta did not respond to *RTO Insider*'s questions on whether the new financing arrangement would transfer more risk to Entergy's ratepayers; who would be responsible for termination fees should Meta take Beignet up on one of the four-year exit options; and whether Meta is prepared to honor its end of the deal as spelled out in the Louisiana PSC's original approval order even with the additional investors involved.

Investigation Request

Earthjustice asked the PSC to launch an investigation to decide whether it was deliberately misled and establish the new financial setup's effect on ratepayer protections. It also said the commission should open a prudence review to figure out whether Entergy Louisiana was aware of the financial reformatting and to decide whether it's wise to allow Entergy to continue with the trio of gas plants.

Finally, Earthjustice said the PSC should direct Entergy Louisiana to file a copy of the "parent guaranty that is executed by Laidley's current parent that does not include a cap on the parent's cumulative liability;" and order Entergy to file a legal opinion clarifying that the parent is bound by the parent guaranty and confirming that termination payments to Entergy must be paid out before investors are compensated.

Meanwhile, Entergy is *seeking* a 10-year property tax exemption worth an estimated $237 million to build the first 1.5-GW natural gas plant for the Meta data center campus. Entergy submitted the application under Louisiana's Industrial Tax Exemption Program, which waives local property taxes on some industrial projects.

Entergy plans to build the more than $2.3 billion Titanium Power Station first, which would consist of two combined-cycle combustion turbines.

Entergy has pledged that Meta will foot the bill for the power station — at least for the contract length of the first 15 years of the generating unit's life — and that it should save ratepayers about $650 million in the long run. ■

Meta data center rendering | *Meta*

NYISO Operating Committee Passes Final Capacity Requirements

Multiple Stakeholders Abstain in Protest

By Vincent Gabrielle

The NYISO Operating Committee has approved the ISO's locational capacity requirements (LCRs) despite multiple stakeholders abstaining from the vote in protest of the process.

"On behalf of Multiple Intervenors and the city [of New York], we just want to express that we are deeply concerned with the process NYISO went through," said Kevin Lang, a lawyer from Couch White who represents large industrial customers and NYC. "NYISO can't surprise, and should not be surprising, market participants with last-minute changes in its methodology."

In addition to the Multiple Intervenors group and NYC, PSEG Long Island and Energy Spectrum abstained from the Jan. 15 vote. All other members voted in favor of the LCRs.

Lang was referring to a presentation given to the New York State Reliability Council's Executive Committee (NYSRC EC), in which changes to the 2026/27 installed reserve margin (IRM) study were discussed and voted on. According to the published *LCR Study*, the IRM report implemented changes to include modeling of the Champlain Hudson Power Express and winter fuel constraints. These changes included modeling of voluntary curtailments and distributed area resources. Transmission security floor values, which are used in the calculation of the LCRs, also were updated.

NYISO control room in Rensselaer, N.Y. | *NYISO*

"The NYSRC EC is concerned with the timing and lack of notice in the NYISO TSL [transmission security limit] methodology and the apparent reversal of previous TSL positions without stakeholder or NYSRC input," NYSRC EC chair Mark Domino was recorded saying in the *meeting minutes*. Domino said the NYSRC would reactivate the Reliability Resource Evaluation Working Group to consider a new reliability rule to address this issue.

The final LCRs were first presented Jan. 6 at an Installed Capacity Working Group (ICAP) meeting. (See *NYISO Presents Final LCRs for 2026/27*.) At that meeting, little discussion of the final LCRs occurred.

The LCRs, expressed as a percentage of peak load forecast, represent the minimum capacity that generators and load-serving entities must maintain within the downstate zones. These zones have substantial transmission constraints.

"We are going to work with the Reliability Council to address the minimum timing issue," said Yvonne Huang, senior manager of ICAP market operations. "We will try to improve the process going forward."

Huang asked NYISO to "never do that again" and requested clarification as to why the ISO waited until the last minute to introduce methodology changes to stakeholders. She said the ISO made the changes because of the reliability need that was discovered in 2025. (See *NYISO Again Identifies Reliability Need for NYC*.)

"I agree we should work better to improve and bring the changes early," said Huang, who added that the changes were first brought up in a Nov. 20 Electric System Planning Working Group meeting. "We were working as fast as we could."

Why This Matters

NYISO's finding of a reliability need for New York City in 2025 triggered an expedited process to change several key methods for calculating locational capacity requirements, a key reliability component of the capacity market.

Jason Ragona, representing Con Edison, issued a statement saying that while the company would vote to support the LCR motion, it wanted on the record that it shared Lang's concerns about rapid changes to TSL and LCR calculations. Ragona encouraged the NYSRC to adopt procedural changes to "minimize" future occurrences.

The representative from PSEG Long Island issued a similar statement to Ragona's, calling for more time to perform complete reviews and comments about any changes.

Other Business

The OC also heard the Operations Report for the New York Control Area for December 2025. The peak load for the month was 23,448 MW around 5 p.m. Dec. 15. That set the winter load record for the year. Wind generation peaked at 2,338 MW on Dec. 18 at 10 p.m. Solar peaked at 2,767 MW on Dec. 22 at 11 a.m. No major emergencies occurred, but seven alert states were issued during the month.

The committee also heard and approved *revisions* to the System Restoration Manual and approved a system impact study *scope* for a data center development on the former site of the Remington Arms Factory in Ilion. The *Associated Press* *reported* on the factory's closure in 2024. ■

Resetting the Reset: Demand Curve Reform Discussions Begin

By Vincent Gabrielle

NYISO kicked off the demand curve reset reform *process* with a discussion of how to improve the overall process and what could be done to strengthen the definition of the proxy unit. The ISO seeks to stabilize the installed capacity market by reducing volatility and making the DCR less complex and burdensome.

"I think, uncontroversially, we can consider this process quite burdensome for both NYISO and stakeholders, and we want to address those issues now as part of a project," said Michael Ferrari, a market design specialist for NYISO.

No specifics, tariff changes, definitions or formulas were discussed. The discussion at the Jan. 12 Installed Capacity Working Group Meeting was centered on possible avenues to improve the DCR and what the ISO might explore with stakeholders.

The DCR anchors capacity prices on a *curve* by picking a "proxy unit" to represent the cost of a hypothetical new generator entering the market every four years. The most recent DCR set a two-hour battery energy storage system as the proxy unit for the 2025/29 period. (See *FERC Accepts NYISO Demand Curve Reset*.)

The current process involves considerable debate, outside consultation and stakeholder meeting time to pick a type of generator to serve as the proxy unit and determine a reasonable hypothetical capital cost estimate for it. Debating the engineering cost assessments to estimate capital costs for potential technology takes much of the 18-month DCR process. These findings are subject to an annual adjustment to try to keep the curve in line with market conditions.

"We want to address the issues now as part of a project before the status quo process of the demand curve reset begins in earnest," said Ferrari.

Ferrari outlined some of ISO's preliminary ideas for smoothing the DCR. The ISO is considering a periodic review that would use the existing annual update framework to apply systemic, formulaic adjustments to reduce the need for a total reset every four years. This would involve using cost-trend publications, inflation-based indexes and various annual financial parameters such as interest rates to adjust prices periodically. This would, in theory, reduce the administrative burden by getting away from detailed engineering studies.

NYISO also is considering redefining the proxy unit. It would no longer be a unit based on specific technology; instead, the proxy unit would merely be a hypothetical unit that meets a minimum operating criterium.

Stakeholders seemed skeptical of NYISO's proposal. Some pointed out that national price indexes were extremely bad at predicting costs in New York City. Others pointed out that the annual adjustment mechanism already doesn't work very well.

"I think it's fair to say, not pejoratively, that the analysis group kind of threw up their hands and said 'Well, there really aren't good indices for certain things so this is as good as it can get,'" said Doreen Saia, a lawyer for Greenberg Traurig, referring to the NYISO consultant's comments during the last DCR. (See *NYISO Offers Final Staff Recommendations for Demand Curve Reset* and *NYISO Stakeholders Continue Debate over Battery as Proxy Unit*.)

Adam Evans, a representative of the New York Department of Public Service, pointed out that the status quo was not tenable.

"In the last reset, we saw a potential $2.5 billion increase in demand curve cost based on what some folks were arguing for the proxy unit, which is frankly untenable," said Evans. "I think this type of proposed solution to limit volatility … I think it makes sense."

© RTO Insider

Other stakeholders pointed out that the current DCR process was not responsive or flexible in the face of state policy shifts. One stakeholder pointed out that state incentives for procuring carbon-free energy were not incorporated into the cost of new entry models. Another said the state climate law could be altered or removed by the legislature if the political winds shifted and any new process would have to account for that.

"I would be very concerned about trying to have a demand curve process that is super responsive to every policy shift that comes at us. That undermines the idea of certainty," said Mike DeSocio, a consultant with Luminary Energy. He disagreed with the idea of a flexible process and asked NYISO to instead focus on market certainty.

Stu Caplan, representing New York Transmission Owners, said the market should not be designed for high price increases without reliability gains. ■

Why This Matters

The demand curve reset sets prices on the capacity market every four years based on a bottom-up cost estimate for a hypothetical new generator. The process is a major time commitment, as is reforming it.

N.Y. Governor Envisions 8-GW Nuclear Fleet

Proposal Comes as Renewable Energy Development Lags

By John Cropley

New York's governor is calling for a "Nuclear Reliability Backbone" of more than 8 GW of the emissions-free baseload power as part of an all-of-the-above energy solution.

The plan was among the more than 200 initiatives Kathy Hochul (D) floated Jan. 13 as part of her *State of the State Address*, the annual forum in which governors present their agenda and priorities for the coming year and its legislative session.

Hochul in 2025 directed the New York Power Authority (NYPA) to develop at least 1 GW of advanced nuclear capacity. Now she is directing the state Department of Public Service (DPS) to facilitate a cost-effective pathway to an additional 4 GW of new nuclear capacity.

"Go big or go home," Hochul said.

New York's existing commercial reactor fleet totals only 3.3 GW.

A confluence of factors faces New York and its policymakers: The state's power portfolio is aging and shrinking as the demands placed on it are expected to grow. NYISO has identified reliability violations *developing as soon as mid-2026*. But the long-running effort to develop renewable generation is lagging behind schedule and is only going to get more difficult under President Donald Trump.

By turning to nuclear energy, Hochul is betting that the many public- and private-sector efforts underway to reduce the staggering cost and tortoise pace of recent U.S. nuclear development will be successful. Limiting rate increases for residents of a state with some of the highest utility costs in the nation has been a theme for the governor, and she reiterated it in her address.

New York ratepayers already contribute around a half-billion dollars a year to subsidize Constellation Energy's four reactors.

Along with technical, regulatory, supply chain and fuel supply hurdles, any U.S. nuclear renaissance will need widespread host-community support.

Gov. Kathy Hochul delivers her State of the State Address on Jan. 13 in Albany, N.Y. | *N.Y. Governor's Office*

Why This Matters

The move would place further emphasis on an energy resource that has been slow and expensive to develop.

NYPA has begun laying the groundwork for this.

It said Jan. 7 that eight upstate communities expressed interest in becoming host communities.

But many people and organizations remain opposed to new nuclear development because of the costs and hazards associated with it.

"The proposal for 5 GW of new nuclear capacity is a dangerous misdirection for state energy policy," Food and Water Watch said. "Nuclear power is a foolishly expensive and antiquated approach to meeting the state's energy demand needs."

Public Power NY called it a disastrous plan and doubled down on its call for NYPA to set a higher goal for renewable energy development.

The Alliance for Clean Energy New York suggested the effort to expedite nuclear development be applied as well to renewables: "New Yorkers need affordable electrons now, not in the decade-plus it will take until new nuclear could be operational. Renewables paired with storage are the cheapest way to deliver more electricity for New Yorkers today."

Advanced Energy United said: "We are optimistic about the governor's plan to move on a suite of advanced energy solutions that are ready to go now that will keep the lights on while protecting consumers."

The newly formed *Future Energy Alliance* is squarely in favor. Constellation, which is part of the broad industry-labor-business coalition, said: "Constellation is proud to support this work and to advance the next generation of nuclear technology that can deliver long-term energy stability and broad economic benefits for communities across the state."

Hochul offered several other ideas *relevant to the energy sector* in the *larger book of proposals* that accompanied her Jan. 13 address. Most are directly keyed to affordability and transparency for ratepayers or other consumer-focused measures.

But she also is advancing Excelsior Power, a new initiative that will direct utilities to treat grid flexibility as a key resource and expand incentives to encourage their customers to participate in demand flexibility programs. This is expected to reduce the need for costly system upgrades.

Hochul wants to reduce the infamous red tape that frustrates energy and housing developers and, by the state's own analysis, causes projects to take up to 56% longer to get from concept to groundbreaking than in peer states. New York has made some progress on this, but delays remain. NYPA and the New York State Energy Research and Development Authority will be directed to update their regulations to speed clean energy development.

Hochul is addressing the human aspect of new nuclear technology with NextGen Nuclear New York, a workforce development effort for the people who will build and operate nuclear plants.

She also is directing the DPS to launch Energize NY Development, an initiative to streamline how large load customers connect to the grid. It will speed up


Constellation's Nine Mile Point nuclear plant in central New York is shown. Gov. Kathy Hochul is proposing a 5-GW expansion of the state's nuclear fleet. | *Constellation Energy Group*

interconnection, she said, and it explicitly will require that projects either cover the costs they create or supply their own energy if they create very large demand without also creating very large job creation or other public benefits.

Other proposals would boost protection of the state grid from cyber threats; adjust rules for aid to school districts to encourage on-site renewable energy development; establish a sales tax exemption for EV charging stations; and expand efforts to encourage agrivoltaics.

But energy was almost a side note in *Hochul's speech*, which focused on quality of life, human rights and affordability issues and drew varying levels of applause from the heavily Democratic audience.

2026 may witness an even more intricate balancing act than is normal in Albany: Hochul, who won the deep-blue state by a surprisingly narrow margin in 2022, is facing a primary *challenge from the left* and a general election *challenge from the right*, plus *skirmishes with the Trump administration* along the way. ■

PJM Board of Managers Selects CIFP Proposal to Address Large Load Growth

By Devin Leith-Yessian

The PJM Board of Managers has selected a path forward for addressing a groundswell of large load interconnections expected over the coming decade. It announced a framework to speed the development of capacity resources, overhaul load forecasting and conduct a holistic review of how each of the RTO's markets can better support resource adequacy needs. (See PJM Stakeholders Reject All CIFP Proposals on Large Loads.)

"This decision is about how PJM integrates large new loads in a way that preserves reliability for customers while creating a predictable, transparent path for growth," said board Chair and interim CEO David Mills. "This is not a 'yes/no' to data centers; this is 'how can we do this while keeping the lights on and recognizing the impact on consumers at the same time?' We look forward to implementing, along with our stakeholders, these proposals to manage the phenomenal demand growth we are experiencing."

PJM board Chair and interim CEO David Mills | © RTO Insider

The proposal is the culmination of the Critical Issue Fast Path (CIFP) process initiated in August 2025 to address large load growth, which resulted in a dozen packages drafted by PJM staff and stakeholders being rejected by the membership in November.

The proposal directs staff to accelerate the reliability backstop to procure additional capacity and define how the related costs will be allocated to load-serving entities (LSEs). This includes exploring mechanisms to assign costs to utilities that are capacity deficient.

What's Next

PJM staff will conduct an analysis in the first half of 2026, followed by a stakeholder process to create a set of recommendations for the board to consider.

The board wrote that the current trigger for the backstop, which requires three consecutive capacity auctions falling short of the reliability requirement, is insufficient in light of the 6.6-GW shortfall in the 27/28 base residual auction (BRA). It also noted that FERC's December 2025 order on co-located loads requested information about proposals to use the reliability backstop to address "acute resource adequacy shortfalls."

The board wrote that the backstop is considered a "transitional measure" to maintain reliability while the holistic market review is ongoing. (See FERC Directs PJM to Issue Rules for Co-locating Generation and Load.)

The board pointed to a joint CIFP proposal from Amazon, Calpine, Constellation Energy, Google, Microsoft and Talen Energy that included an alternative reliability backstop triggered if a capacity auction clears below 98% of the reliability requirement. It would open an auction for multiyear capacity commitments for new resources or those outside the capacity market. While the board did not mirror the coalition proposal, it wrote that proposals should "specify price, term and quantity as core award parameters." (See "Joint Stakeholder Proposal," PJM Stakeholders to Vote on Large Load CIFP Proposals.)

PJM's CIFP proposal requested a second phase of the process to evaluate changes to the reliability backstop and incentives for large loads to bring their own generation or participate in demand-side capacity resources. (See "PJM Proposal," PJM Stakeholders to Vote on Large Load CIFP Proposals.)

A backstop auction was requested by governors of PJM states and the White House in a statement of principles released Jan. 16. It calls for the auction to be conducted by September 2026 to allow "15-year price certainty" for new capacity resources. The costs resulting from the auction should be allocated to LSEs that have not procured their own capacity or agreed to be curtailable. (See related story White House and PJM Governors Call for Backstop Capacity Auction.)

Another parallel between the statement of principles and the board's proposal lies in the price collar limiting capacity prices to between $175 and $325/MW-day for the 2026/27 and 2027/28 capacity auctions. The statement requested that the collar be extended for two years, while the board requested feedback from stakeholders on such an extension.

During a press conference following the announcement of the 2027/28 BRA results, PJM said the auction would have cleared at $529/MW-day without the collar and the Dominion zone would have separated at $542/MW-day. (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor* and *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

The board's proposal adopts staff's recommendation to create a bring-your-own-new-generation pathway allowing new capacity paired with large loads to qualify for a fast-tracked interconnection process, expected to be rolled out by August 2026.

Large loads exceeding available incremental new resources within an LSE would be subject to curtailment under the proposal, under a model similar to the CIFP proposal sponsored by several state legislators, consumer advocates and the NRDC. The large loads would be curtailed prior to pre-emergency load management, which the board wrote is intended to avoid disrupting other demand response participants.

"Should system conditions over a given period force PJM to invoke its emergency procedures, the board finds it reasonable for certain large loads, including data centers, to move to their backup generators, or curtail their demand, for a limited number of hours during the year to prevent a larger-scale outage for residential and other consumers. Such curtailment would be expected to occur infrequently, for limited durations and only when necessary to prevent broader system impacts, consistent with PJM's longstanding operational practice of avoiding curtailment whenever possible," the board wrote.

The board directed a slate of changes to PJM's load forecasting process, including a pathway for state utility commissions to review large load adjustments (LLAs) submitted by utilities, requirements for utilities to inquire with customers seeking service for large loads about whether they are exploring multiple sites for a single project, and a third-party review of the forecast to identify national trends that may impact PJM's assumptions.

The holistic review of PJM's markets is intended to improve how the energy, reserve and capacity markets create the incentives needed to meet resource adequacy. Staff will conduct an analysis in the first half of the year, followed by a stakeholder process to create a set of recommendations for the board to consider.

"PJM is establishing clear, transparent guardrails for integrating large new loads under defined conditions," PJM Chief Operating Officer Stu Bresler said in the Jan. 16 announcement of the board's proposal. "This proposed course of action will require intense work by all of us in 2026 and involve significant changes. But it's clear that bold action will be required to support the positive growth that is happening throughout the PJM region and the nation." ■

White House and PJM Governors Call for Backstop Capacity Auction

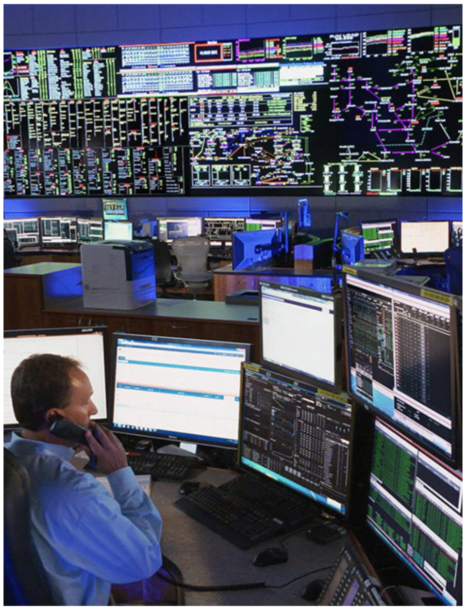
By James Downing

The White House and governors in PJM states have released a *plan* to get more generation built in the RTO, which saw its recent capacity auction clear short of the target as data center demand proved too much to meet. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

"Under President Trump's leadership, the administration is leading an unprecedented bipartisan effort urging PJM to fix the energy subtraction failures of the past, prevent price increases, and reduce the risk of blackouts," White House spokesperson Taylor Rogers said Jan. 16.

The most immediate idea is to run a special auction that would procure generation for data centers, which they would pay for. Trump and the White House's National Energy Dominance Council (NEDC) said they've reached agreement with several states to advance more than $15 billion of new generation projects and a "coalition of leading technology companies has committed to funding" the new capacity.

"This initiative will ensure we usher in the age of artificial intelligence with new power plants funded by the technology companies, not taxpayers, securing the steel of Pennsylvania, the manufacturing of Ohio and the ships of Virginia," NEDC Chair and Interior Secretary Doug Burgum said in a statement.



PJM control room | *PJM*

The plan is to run a reliability backstop auction to procure the new capacity and give it 15-year contracts paid for by data centers. PJM's tariff allows for a backstop capacity auction, but only after its main capacity auctions fall short for three years, so implementing it would require a rule change.

"PJM is reviewing the principles set forth by the White House and governors," PJM said in a statement. "The PJM board's decision, resulting from a multimonth stakeholder process on integrating large load additions, will be released later today. The board has been deliberating on this issue since the end of that stakeholder process. We will work with our stakeholders to assess how the White House directive aligns with the board's decision."

PJM planned to release its proposed reforms on the afternoon of Jan. 16, just hours after the governors met with the NEDC at the White House to sign their deal.

The NEDC and governors also called on the RTO to improve load forecasting and queue management and to return to "market fundamentals" with long-term capacity market reforms that should go into effect in time for the Base Residual Auction scheduled for May 2027. They suggest extending the price cap that has been in place for another two capacity auctions.

The governors agreed to use their powers to ensure that state regulators assign the costs from the backstop auction to data centers that have not otherwise procured supply or have agreed to flexible operations.

Pennsylvania Gov. Josh Shapiro (D) said in a statement that he's been working to get power prices under control for two years and welcomed the deal with the White House and fellow governors.

"I sued PJM when they refused to act and secured a price cap that saved consumers tens of billions of dollars on their energy bills," Shapiro said. "Since then, I've been working with my fellow governors and federal energy officials to push PJM to make needed reforms, and I'm glad the White House is following Pennsylvania's lead and adopting the solutions we've been pushing for — including the extension of the price cap that I insisted be included today."

Why This Matters

PJM's capacity auction fell short for the first time after a couple years of rising prices, and now the NEDC and governors are hoping to shore up reliability there while meeting huge new demand from data centers.

Former FERC Chair Mark Christie welcomed the commitment for data centers to pay for the capacity they need to connect to the grid.

"In the Susquehanna case and the PJM co-location 206 proceeding initiated when I was chairman, that is exactly the principle I advocated, so I am glad the president and the governors are endorsing it," Christie said. "Now I am interested to see the details of how PJM can or will implement this type of emergency auction for a 15-year PPA."

The NEDC and governor's proposals endorse the idea of "bring your own generation" with a special procurement auction, and that all makes sense, said PJM Independent Market Monitor Joe Bowring.

"One question is, how will those costs from the procurement be assigned to data centers and … is that literally a 15-year contract with the data centers that they have to pay regardless, or is there any risk that some of that cost will be shifted to load?" Bowring said. "So, I mean, this is an example of a question that you know is yet to be answered. But at a high level, it's a positive, but there are a lot of details to be worked out."

Based on the governors' commitment on cost allocation, PJM likely will assign the costs of the special auction to load-serving entities and let the state regulators figure which data centers ultimately pay, he added. The question is who would cover the stranded costs if those data centers were to go away before the 15-year contracts expire, Bowring said.

Speaking at the American Enterprise Institute a couple of days before the PJM deal was announced, NEDC Senior Director of Power Peter Lake (the former Texas Public Utilities Commission chair) highlighted the issue around mismatched time scales in the two industries.

"Consuming electricity is not new to America, but it's the timing that is unique, both in a challenging way, but also it presents an opportunity," Lake said. "The speed which with which these large consumers of electricity come to market is certainly a new paradigm."

Building major industrial facilities in the past often had similar time frames to building power plants: four to six years, and they both last for decades. Data centers take 18 to 24 months to be developed, and then the chips used in them become obsolete much more quickly than a factory's assembly line.

"The technology inside the data center might be obsolete before the power plant is even built," Lake said. "If you think of the value of the data center and the GPUs, that's how fast the innovation is going, which is a good thing. We want the innovation. … We want to accelerate that. That's the beautiful part of AI and all the wonderful things it can bring to enhance our lives, but that is such a staggering shift."

That dynamic makes predicting data center load difficult, Bowring said.

"To me, the best way to manage the forecast is make the data center responsible for paying for whatever capacity they need," he added. "So that gives them incentive to be as serious as possible building the data center. And if they incur the cost and then go walk away, then those costs stay with them."

While Bowring sees the increased attention to the reliability crisis in PJM as generally good, nothing in the deal announced will negate the impact the growth in data centers already has had on consumers in PJM.

"We would not have this crisis but for data center load," Bowring said. "So regardless of retirements, regardless of the economics of power plants — regardless of even PJM's interconnection queue process difficulties, shall we say, holding all that constant — we would not have these problems, not be short, but for data center load. Data center load is forcing PJM to be short, and it's imposed $23 billion worth of costs on customers."

The gap between supply and demand is about 13,000 MW, but any backstop auction could be rounded up to a more even 15,000 MW, Bowring said.

The White House and politicians are not this involved in wholesale power markets, but Grid Strategies President Rob Gramlich noted in an interview that under President Bill Clinton, there was a coordinated effort to deal with the fallout from the California energy crisis by getting new contracts in place to keep power flowing.

The situation needs fixing, but the documents released about the plan are sparse on details, and those will be important, Gramlich said.

"There's a bigger picture than this tries to address, that FERC didn't address and didn't have before the commission, which is new load came into the region and started buying up power from existing generation capacity," Gramlich said. "And I think the states and consumers in the region thought that those power plants in the PJM region were there to serve them. They thought they could count on them, but unfortunately for them, those power plants had not committed their power under any contract."

Gramlich has argued for years that power plants in the region needed long-term contracts, a position he came to after dealing with the California energy crisis, in which state rules requiring utilities to buy entirely from the spot market made things much worse.

State regulators and others in PJM did not heed his warnings largely because there were no counterparties big enough to take on the major, long-term contracts that hyperscalers have announced recently. Still other wholesale power markets with restructured states like Texas have had more long-term contracting than PJM, he added.

"The fact that the large buyers are willing to say they'll pay their fair share and [are] willing to work with the bipartisan group of governors, and with the federal government to reach a conceptual proposal here, I think is very noteworthy," Gramlich said. "And PJM does have the ability to do backstop auctions that are separate from its capacity market. So, I think there's potentially a workable concept there."

A big question is how the cost allocation and retail side of these reforms is handled. Gramlich indicated it ultimately might require an expansion of federal authority.

Everyone agrees PJM is struggling to add new generation and that some sort of intervention is required, but Aurora Energy Research's USA East head Julia Hoos sounded a note of caution.

"This type of 'out of market' action can quickly add new generation, but may be financially disastrous for existing generation, which ultimately hurts reliability in the entire region," Hoos said.

The separate auction is likely to reduce price signals for existing units and could affect the financial health of coal plants in PJM, which the Trump administration likes to keep open.

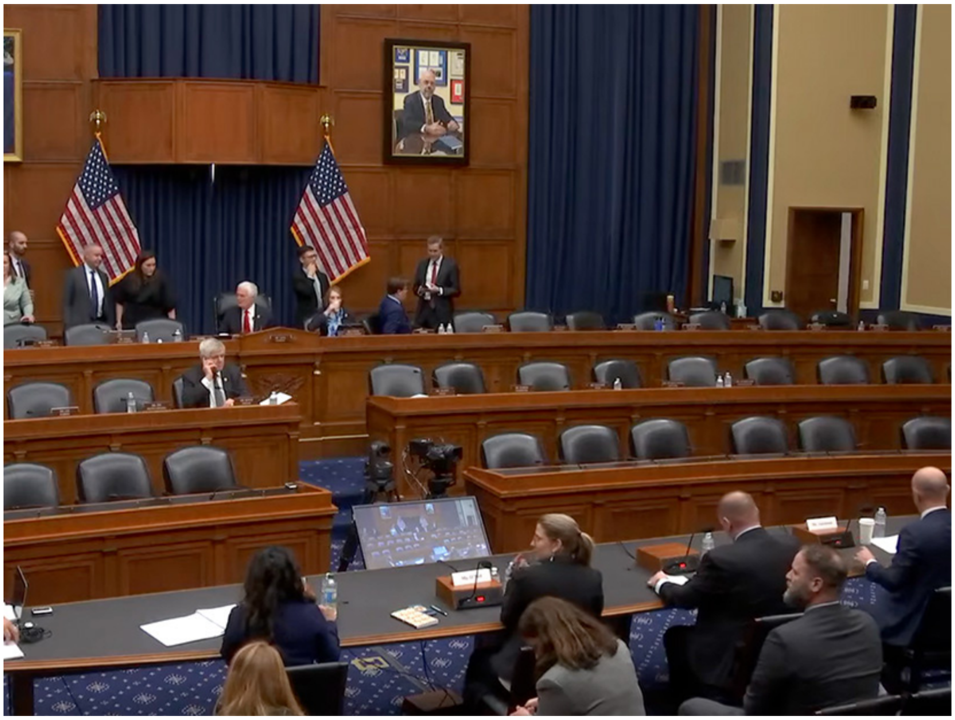
"Investor confidence to build new power generation in PJM has been low for years," Hoos said. "Prices were low for almost a decade, and generators were shutting down, and no one was intervening to keep them online. Now that prices are high, PJM and lawmakers are intervening to keep them low. Understandably, developers willing to build new generation in PJM saw that as a substantial risk. Now, this action means that any existing generation is likely to see significantly lower prices, confirming those fears."

In a thread on *X*, LS Power CEO Paul Segal made similar points to Hoos and cautioned that the special auction needs to be treated as a bridge.

"Bottom line: Shifting toward 'pay your own way' is directionally right," Segal wrote. "Just don't confuse a one-off auction (or a permanent cap) with the solution. The durable fix is stable rules + earlier signals + faster pathways to connect + true cost-causation — so competition can do its job." ■

DOE Official Faces Questions on PJM Resource Adequacy at House Hearing

By James Downing



The House Energy and Commerce Subcommittee on Energy holding its legislative hearing Jan. 13 | *House Committee on Energy and Commerce*

Democrats used a House Energy and Commerce Subcommittee on Energy hearing on bills to shore up the electricity sector's physical and cyber security as an opportunity to criticize Trump administration policies affecting resource adequacy in PJM.

"This is an area where the committee has a history of bipartisan success, and we should build on that," Rep. Kathy Castor (D-Fla.), ranking member of the House Energy and Commerce Committee, said during the Jan. 13 hearing.

"However, we cannot ignore that right now, the greatest threat to grid reliability and security is the president and Republican policies. The arbitrary project cancellations, higher cost and uncertainty have driven the country into an electricity crisis," she said.

Castor criticized the Trump administration's December decision to revoke permits for the country's remaining offshore wind projects, some of which were close to completion. Developers have challenged that decision in court and already won an early victory. (See *Judge Again Lifts Revolution Wind Stop-work Order*.)

Castor asked acting Secretary of Energy Alex Fitzsimmons whether he had a role in any of the administration's orders under Section 202(c) of the Federal Power Act to keep fossil fuel-fired power plants open, to which he said he did as director of Office of Cybersecurity, Energy Security, and Emergency Response.

Why This Matters

While Congress might have a few months to pass legislation before attention moves to the midterms, the hearing showed that Democrats have little appetite for working with an administration that is attacking their states' energy policies.

In response to a follow-up question, Fitzsimmons affirmed that orders to keep open the Eddystone plant in Pennsylvania came in response to a looming shortage of supply in PJM. (See *Energy Secretary Wright Issues 3rd Order Keeping Eddystone Open*.)

"If you believe there is an energy shortage in PJM, why did you take what the federal court described as an 'arbitrary and capricious action' to cancel offshore wind projects that were permitted and ready to go?" Castor asked.

Fitzsimmons said PJM had asked DOE to issue the 202(c) order and that Eddystone has supported grid reliability since the first such order was issued last May.

"Offshore wind is some of the most expensive energy that exists," Fitzsimmons said.

Castor responded that canceling projects at the last minute is very expensive as well.

"A business has invested billions of dollars," Castor said. "They've gone through and they've gotten permits. They've hired a bunch of people, and then at the 11th hour, a president who's focused on retribution, who the court said 'acts in an arbitrary and capricious manner,' comes and takes a hatchet to it, and it's costing people a lot of money, and they're angry about it."

The Department of the Interior ultimately made the decision to withdraw the permits for offshore wind plants, Fitzsimmons said.

Castor asked to enter into the record a *brief* from PJM that was filed with a federal court recently to support Dominion Energy's request to overrule the stop-work order on its Coastal Virginia Offshore Wind (CVOW) project.

"The CVOW project, with a nameplate rating of 2,489 MW, is an integral component of needed new generation that PJM has been relying upon to timely achieve commercial operation," PJM said in the brief. "The CVOW project's continued development and ability to produce 2,489 MW for the interstate grid will help mitigate the capacity shortfall PJM is now experiencing, which is projected to continue into the future."

Extended delay of the project will cause "irreparable harm" to the 67 million Americans served by PJM given its critical need for new generation to achieve commercial operation in the next few years, the RTO added.

Later during the hearing, Fitzsimmons defended the 202(c) orders in more depth, saying they are needed in response to shrinking reserve margins in all the major ISO/RTOs at the same time they need to grow supplies to meet new demand.

"To meet the reserve margin requirements that are necessary for future load growth and to win the AI race, we need capacity that gets accredited by the grid operators, and that is dispatchable capacity," Fitzsimmons said. "So, you can build as much non-dispatchable capacity as you want. It does not obviate the need for more always-on electricity."

Cyber and Physical Security Legislation

While the minority took the opportunity to conduct an unofficial oversight hearing, the committee also took testimony on several bills, including the SECURE Grid *Act* from Subcommittee Chair Bob Latta (R-Ohio) and Rep. Doris Matsui (D-Calif.). It would give states funding to study the resilience and security of their electric grids.

Another piece of *legislation* would extend the operation of the Energy Threat Analysis Center (ETAC), which was set up as a pilot to improve information sharing on security threats to the industry.

"The ETAC Reauthorization Act of 2025 promotes improving operational collaboration between the government and industry securing critical energy infrastructure from cyber threats and protecting information sharing, thereby strengthening the nation's energy security," Fitzsimmons said.

In his written testimony, Edison Electric Institute Vice President Scott Aaronson said one way Congress could help the industry is by limiting its liability when it follows government directions during a security event.

"The government may order utilities to ensure certain areas have power during an emergency for national security purposes," his testimony said. "Or, conversely, an agency may ask that a utility allow a threat to persist to support an investigation. While utilities stand ready to collaborate with the federal government to address threats and emergency situations, existing law does not provide sufficient legal liability protection for utilities that accommodate such an order."

Both the American Public Power Association and the National Rural Electric Cooperative Association asked the committee to extend DOE's Rural and Municipal Utility Cybersecurity Program.

"We operate in resource-constrained rural areas, defending lines and substations that are often remote and difficult to access," Dairyland Power Cooperative Vice President Nathaniel Melby told the subcommittee. "We operate on thin margins without profit incentives or shareholders. We must balance costly security needs against the financial reality of our members. Every dollar we invest in cyber defense comes directly from our members' pockets."

DOE's program for municipal utilities and co-ops helps the close the "rural resource gap" while building partnerships, collaboration mechanisms and information sharing capacities, he added in testimony made for NRECA. ■

Pessimistic PJM Slightly Decreases Load Forecast

Estimate Likely to Cut into 2028/29 BRA Shortfall

By Devin Leith-Yessian

PJM's 2026 load forecast has decreased the amount of growth expected for the following six years owing to a more pessimistic view of the volume of large loads, economic growth and electric vehicles.

The forecast continues to expect that load growth will accelerate over the 20-year scope, with load reaching 253 GW in 2046.

Load growth still is expected in the near term, just slower — particularly in the winter. For the summer of 2028, the total load expected is 2.6%, or 4.4 GW, lower than the 2025 forecast; for the following winter, the estimates are 3.8%, or 5.8 GW lower. Between 2027 and 2031, the summer peak is expected to grow to 191 GW, up 30 GW. By 2046, the peak is expected to reach 253 GW for the summer and 237 GW in the winter.

PJM said the forecast was likely to cut into the 6.6-GW shortfall in the 2028/29 Base Residual Auction (BRA). While the haircut is not enough to make up the difference, the RTO said it also expects some resources scheduled to deactivate and winter-only resources without an annual commitment to be available. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

Data center load growth has been the primary cause of the growing capacity shortfall and billions of dollars in transmission projects. The Board of Managers is considering a slate of proposals to rework the capacity market to address large loads, as well as an $11 billion Regional Transmission Expansion Plan to increase transfer capability into growing load clusters in Virginia, Pennsylvania and Ohio. ■

Changes From 2025 Long-Term Load Forecast

Year	Summer Peak (MW)	Change From 2025 Long-Term Load Forecast (MW/%)	Year (Winter Season Dec. – Feb.)	Winter Peak (MW)	Change From 2025 Long-Term Load Forecast (MW/%)
2027	160,451	-3,735 (-2.3%)	2026/27	142,536	-4,155 (-2.8%)
2028	165,567	-4,414 (-2.6%)	2027/28	147,807	-5,759 (-3.8%)
2029	171,530	-4,564 (-2.6%)	2028/29	153,434	-6,186 (-3.9%)
2030	183,008	-875 (-0.5%)	2029/30	160,126	-7,111 (-4.3%)
2031	191,017	-1,630 (-0.8%)	2030/31	172,202	-3,994 (-2.3%)
2035	216,872	+6.949 (+3.3%)	2034/35	199,622	+1,477 (+0.1%)

| *PJM*

D.C. Circuit Vacates FERC Order Requiring PJM to Rerun 2024/25 Capacity Auction

By Devin Leith-Yessian

The D.C. Circuit Court of Appeals has vacated FERC's decision to order PJM to rerun its 2024/25 capacity auction without a tweak to the parameters for the DPL South zone. The court ruled that the commission was not justified in dismissing a complaint from consumer advocates arguing that the PJM auction results were not just and reasonable due to the unresolved flaw in the parameters. (See *3rd Circuit Rejects PJM's Post-auction Change as Retroactive Ratemaking*.)

The court ruled that the commission incorrectly determined that revising the 2024/25 Base Residual Auction (BRA) results would violate the filed-rate doctrine. FERC took that stance in the wake of the 3rd U.S. Circuit Court of Appeals in March 2024 finding it had run afoul of the doctrine by permitting a PJM request to revise the locational deliverability area (LDA) for DPL South in December 2022 after the bidding window had closed but before the results were posted. The RTO said it had identified a "mismatch" in the capacity expected to be available in the region versus what was offered. The DPL South zone encompasses the Delmarva Peninsula. (See *PJM Decides Against Posting Indicative Capacity Auction Results*.)

PJM intervened to defend FERC's order, along with the Electric Power Supply Association, PJM Public Power Providers Group, Midwest Generation, Constellation Energy and NRG Business Marketing.

The court's Jan. 13 ruling states that the 3rd Circuit had applied only to the request to revise the reliability requirement and did not necessarily bind the commission from revising the BRA results if they are determined to be unjust and unreasonable.

"There may have been a sound basis for FERC to deny relief. But the only reason it articulated — that the 3rd Circuit resolved the matter — was anything but sound. The 3rd Circuit held that the filed-rate doctrine foreclosed FERC's efforts to modify PJM's rate-setting process under Section 205 of the [Federal Power Act]. But it never addressed whether the auction result is subject to revision under Section 206. FERC's conclusion to the contrary was erroneous," the court wrote.

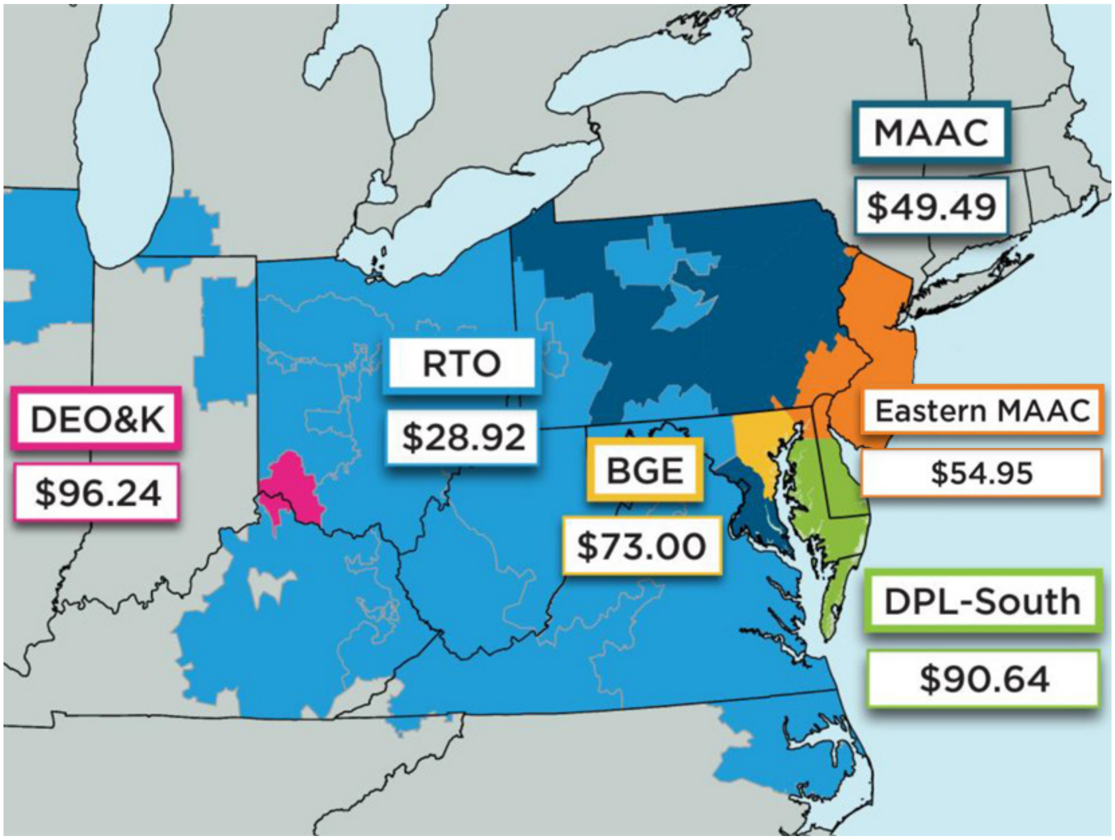
The court was not swayed by the commission's arguments that the 3rd Circuit anticipated the economic effects of its ruling and therefore it could not act in a way that would render the court's expectations meaningless. The Jan. 13 ruling states that courts are not economic regulators and the 3rd Circuit's ruling could be interpreted as acknowledging that FERC had multiple paths it could proceed with, not solely requiring it to direct PJM to rerun the auction.

The vacatur did not direct the commission to take any particular action, and it cautions that a reversal of the auction results is not guaranteed.

"We do not mean to suggest that the DPL customers are necessarily entitled to a refund under Section 206(b). We hold only that labeling the relief they seek as "retroactive" should not foreclose the possibility that it is available under Section 206," the court wrote.

Maryland People's Counsel David Lapp said the ruling is a step toward reversing a PJM mistake that cost ratepayers $180 million.

"Delmarva Peninsula customers paid the consequences of a mistake PJM made — a mistake that gave generators a windfall, and one that federal regulators failed to fix. The court's decision significantly advances the possibility that customers will be made whole through refunds," Lapp said in a statement. ■



Capacity prices in the DPL South zone increase significantly as a result of a mismatch in the amount of capacity forecast in the zone and that which offered. | *PJM*

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Jan. 22. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will cover the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to the Regional Transmission and Energy Scheduling Practices document to codify the NAESB version 4.0 Business Scheduling Practice Standards.

C. Endorse proposed *revisions* to Manual 2: Transmission Service Request drafted through its periodic review.

D. Endorse proposed *revisions* to Manual 21B: PJM Rules and Procedures for Determination of Generation Capability to expand the definition of dual-fuel gas generation to include configurations where the secondary fuel is stored off-site but directly connected to the resource with a dedicated pipeline. (See "Stakeholders Endorse Expanded Dual Fuel Manual Definition," *PJM PC/TEAC Briefs: Jan. 6, 2026.)*

Issue Tracking: *Capacity Market Enhancements — ELCC Accreditation Methodology*

E. Endorse proposed *revisions* to Manual 28: Operating Agreement Accounting drafted through the document's periodic review. The changes seek to clarify the opportunity cost calculation for hydro units, how day-ahead load response bids are included in the day-ahead operating reserve charges and the calculation of capped real-time synchronized reserve assignments for demand response.

F. Endorse proposed *revisions* to Manual 38: Operations Planning proposed as part of its periodic review. The language details the long-term study process included in the Regional Transmission Expansion Plan and adds MISO solar generation to planning studies.

Endorsements (9:10-9:35)

1. 2026/2027 3rd Incremental Auction (IA) Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) (9:10-9:35)

PJM's Josh Bruno will *present* the recommended IRM and FPR values for the 2026/27 Third IA, which is scheduled to be conducted on Feb. 24. The parameters were calculated with the 2026 load forecast, which scaled back PJM's estimates of the load growth anticipated for the delivery year. This resulted in staff recommending an IRM of 18.6%, 0.5% lower than the margin used in the Base Residual Auction, and a 0.9291 FPR, 0.0121 higher than the BRA.

Stakeholders will be asked to endorse the parameters upon first read and same-day endorsement will be sought at the Members Committee meeting.

Members Committee

Endorsements (11:00-11:30)

1. Minimum Capitalization (11:00-11:15)

PJM's Ryan Jones will *present* a proposal to increase the minimum capitalization requirements to participate in its markets. It would double the tangible net worth requirement for market participants and add a 3% annual escalator. (See *PJM Presents 1st Read on Minimum Capitalization Requirement Proposal*.)

Issue Tracking: *Review of Minimum Capitalizations for Participation in PJM Markets*

2. 2026/2027 3rd Incremental Auction (IA) Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) (11:15-11:30)

If endorsed by the MRC, Bruno will present the recommended IRM and FPR values for the 2026/27 Third IA.

The committee will be asked to endorse the values on first read. ■

FERC Approves SPP Large Load Interconnection Process

By Tom Kleckner

FERC has approved SPP tariff additions that deploy novel study processes to quickly review requests for "high-impact" large loads seeking to interconnect to its system.

The new attachments to the tariff incorporate transmission, generation and load interconnection services into a single framework, effective Jan. 15. They establish a 90-day study-and-approval process for interconnecting large loads that will be paired with new generation or with current or planned generation (*ER26-247*).

In its Jan. 15 order, FERC said SPP showed that "unprecedented" growth in large loads in its footprint presented "significant and unique operational and planning challenges." It found the grid operator's addition of a high-impact large load (HILL) study and high-impact large load generation assessment (HILLGA) processes address those challenges "while maintaining the reliable operation of SPP's transmission system."

SPP CEO Lanny Nickell said in a *statement* that the grid operator is proud that it is "first in the nation" to blend transmission, generation and load interconnection services into a single framework.

"It's essential to our nation's competitive future that we can quickly, reliably and affordably meet vastly increasing energy demands," he said. "We are now in a great position to enable this future."

SPP defines HILLs as new commercial or industrial load, or an increase in the load, at a single site connected through one or more shared interconnection or delivery points, and where load is either 1) 10 MW or more if connected to the transmission system at a voltage level less than or equal to 69 kV; or 2) 50 MW or more if connected at a voltage level greater than 69 kV.

Customers registering their load as HILLs and with plans to acquire generation will get a 90-day study and provisional approval, with upgrades directly assigned until the customer acquires firm service for the new generation. They will not be required to have current generation or a generator interconnection agreement.

Under the HILLGA process, HILL customers bringing supporting generation will also receive a 90-day study and a limited interconnection agreement. Upgrades will be directly assigned to the generation customer.

Commissioner David Rosner filed a concurring opinion calling on other U.S.

SPP's interconnection process for large loads includes 90-day studies. | *Amazon*

Why This Matters

SPP says the 90-day study processes interconnecting large loads paired with new generation or with current or planned generation is the "first in the nation" to blend transmission, generation and load interconnection services into a single framework.

transmission providers to consider similar proposals to SPP's "pragmatic steps" supporting economic growth in its footprint.

"Today's order is a productive step toward facilitating the energy needed to win the AI race, bring back American manufacturing, and deliver the reliable and affordable energy on which families and small businesses depend," he wrote.

FERC noted SPP's filing contained several "ministerial errors" and directed the RTO to make a compliance filing within 30 days.

SPP developed the processes following a May directive from board Chair John Cupparo that staff deliver a timely, scalable and reliable approach to manage the exponential growth of load demand across the footprint. Staff's first attempt was rejected by members in July before a revised version won endorsement from stakeholders and then the board in September. (See "Large Load Integration OK'd," *SPP Board Approves 765-kV Project's Increased Cost*.)

A third service, conditional high-impact large load service (CHILLS), was split out from the HILL/HILLGA policy package to give stakeholder groups sufficient time to refine and address concerns. Stakeholders have since approved the final framework and its two paths for load's conditional connection.

SPP's board will consider the CHILLS framework during its Feb. 3 meeting in Little Rock, Ark. ■

SPP's MOPC Adds Conditional IC Process for Large Loads

By Tom Kleckner

SPP stakeholders have overwhelmingly endorsed a conditional interconnection process for large loads that will be paired with two other FERC-approved processes as part of the grid operator's effort to approve large loads.

The conditional high-impact large load service (CHILLS) tariff revision request (*RR720*) gives load two paths for conditional connection: CHILLS with sufficient designated resources but contingent on transmission upgrades, and a large-load generation assessment that requires accredited, equivalent support generation for the CHILL.

"Ultimately, we have what I would consider a policy that has a narrower scope than initially proposed before," Yasser Bahbaz, senior director of operations, told the Markets and Operations Policy Committee during its Jan. 13-14 meeting. "It's that way because it does address, and is designed to address, concerns with respect to impact to the system, from a market impact and market-energy pricing standpoint, and also from a reliability standpoint."

The CHILLS proposal was split in September from the policy package that included a high-impact large load (HILL) study and high-impact large-load generation assessment (HILLGA) to give stakeholder groups more time to refine and address concerns expressed with the CHILL policy. FERC approved the HILL and HILLGA policies Jan. 15. (See related story *FERC Approves SPP Large Load Interconnection Process*.)

The HILL/HILLGA proposal accelerated studies and access to interconnection information, but market participants without generation cannot establish a delivery point for the HILL study. CHILLS expands on that policy to enable speed to power, not just speed to information, Bahbaz said.

"[HILL] information was basically saying, 'This is what it takes, this is what it costs, and these are upgrades that are needed for these large loads to interconnect,'" he said. "So, we are taking it from just a speed to information to speed to power."

SPP's Market Monitoring Unit said that with recent revisions to the proposal, it now supports the CHILLS policy. However, it called for the RTO to document that it will commit reliability status resources or make local reliability commitments only to supply firm load and ensure consideration in determining whether a participant has sufficient capacity to "cover" a CHILL with associated generation.

MMU lead Carrie Bivens noted that load-responsible entities (LREs) can use the same megawatts for both the planning reserve margin and to cover a CHILL.

"It's the exact same megawatts of capacity that are pointed at two different purposes," she said. "It does make the region reliant on essentially perfect responses from resources and CHILLS in order to mitigate reliability risks."

Defining Terms

- **HILL:** high-impact large load
- **HILLGA:** high-impact large-load generation assessment
- **CHILL:** conditional high-impact large load
- **CHILLS:** conditional high-impact large load service

MOPC members endorsed the proposal with 99.3% approval, although there were 43 abstentions. There were only five no votes.

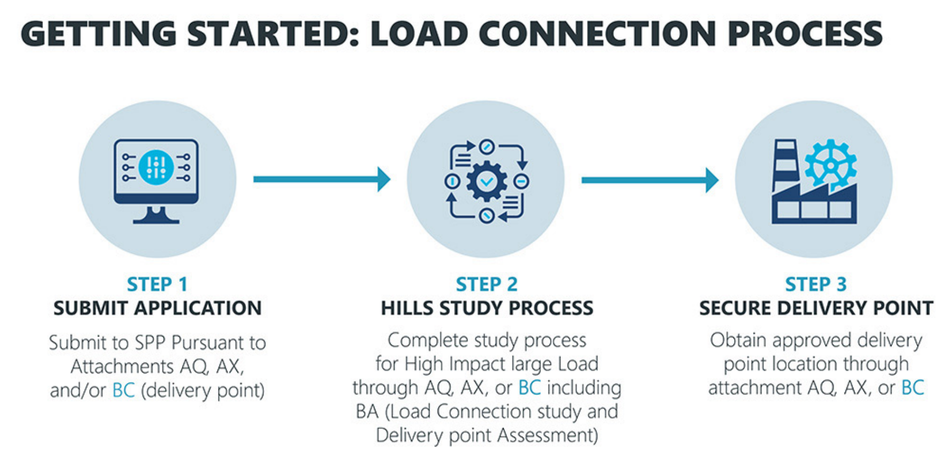
Peak Demand Assessment Delayed

MOPC members voted to direct staff to modify revision request *RR703* by altering the proposed peak demand assessment (PDA) to focus only on the forecast effects of load-modifying demand response resources (LMRs). The revised tariff change is to be brought back to working groups before the April MOPC meeting.

The endorsed motion was crafted as a compromise after a previous motion amending a Supply Adequacy Working Group recommendation to include a cap on LMRs based on 2025 actuals or workbook submittals failed. Members cited concerns over the load forecast's evaluation while expressing support for the RR's demand-response portion.

"I was hoping that this wouldn't happen," Evergy's Jim Flucke, chair of the Market Working Group, said in offering the compromise motion. "It would allow for another three months to allow us to work through some of the concerns in the PDA. The big difference that we're proposing is that we focus PDA strictly on the demand response."

Flucke said the demand response piece would remain as "previously envisioned." He said the key hurdle is working through



The CHILLS load-interconnection process | *SPP* demand response's deployment and how "that's going to fit into this approach of being able to evaluate your demand response portion and how well it is meeting what your expectation was in your workbook."

SPP staff said they can work with the three-month delay in adding "increasingly critical" demand response as the RTO addresses rapid load growth, evolving resource mixes and tighter energy conditions. Natasha Henderson, senior director of grid asset utilization, said the grid operator will be reliant on FERC approval if it is to implement a revised PDA forecast in 2028 and with risk mitigation for 2027 "that isn't full implementation."

"I think this is doable … while I ask for 60 days [for FERC action], I suspect it's going to be more like 180 days, given the contentious nature of this policy," Henderson said.

RR703 is intended to increase the visibility and ability to deploy demand response by creating a participation model and accreditation framework for non-price-sensitive DR. SPP wants to incent LREs to manage peak loads by qualifying non-registered or load-modifying demand response capable of performing when their peak loads exceed their qualified resources. (See *REAL Team Endorses DR Policy, CONE Value*.)

In other actions, MOPC:

- Approved base planning reserve margins for the RTO Expansion members of 19 and 40% for the summer and winter seasons, respectively. The PRMs are effective in 2027 to give the RTOE members time to adjust to integration into SPP. They were based on a loss-of-load expectation study and other analysis directed by an RTOE ad hoc study group and other stakeholders. The RTOE is one-tenth the size of SPP, with a little more than 5 GW of accredited capacity.
- Endorsed a proposed tariff revision (*RR534*) that limits long-term firm services up to the interconnection limit at the point of interconnection for modeling and controlling energy storage resources hybrid configurations.

Wyoming Transmission Outage

A November grid disturbance resulted in a significant "uncontrolled" loss of generation (4 GW) and load (1 GW) across Wyoming and into western South Dakota, staff told MOPC.

The Nov. 13 event in the Western Interconnection began with the planned removal of a 500-kV transmission line in the PacifiCorp balancing authority area. That led to the immediate loss of another 500-kV line that triggered cascading outages around 12:34 p.m. (MST).

SPP's Derek Hawkins, director of system operations, said the RTO's reliability coordinator operators immediately responded to address severely loaded transmission constraints, working across internal and external transmission operators and the neighboring RC to return the system to a "secure operating state."

"We did that very quickly … to get the system in a spot where we could start the restoration," he said, noting the restoration was completed in the evening of Nov. 13.

NERC and WECC have launched a coordinated investigation into the event. Hawkins said they are likely to file a detailed report that covers the root causes, contributing factors and lessons learned from the event.

Hawkins also said high winds in December resulted in several new marks for wind generation, eventually topping out at 26.3 GW on Dec. 19. SPP's previous high came in August 2025 at 24.3 GW.

Dueling CSP Studies

SPP staff told members that its joint operating agreement with MISO requires another joint study in 2026, even as the grid operators are completing their 2024 study.

The two RTOs have conducted preliminary screening analyses of 31 projects, using both original coordinated system plan (CSP) models and those that incorporate approved transmission projects from 2025. Staff will focus next on 14 projects, primarily along the southern seam in Arkansas, Louisiana, Oklahoma and Texas, in evaluating their reliability, economic and transfer benefits.

"We will begin to build a business case for any projects out of those 14 that make it through, that we want to even consider a little more in terms of benefits calculation," Clint Savoy, SPP's manager of

Jim Flucke (right), Evergy | © *RTO Insider*

interregional strategy and engagement, told MOPC. "We will start having conversations about cost allocation … and we expect those conversations to continue through this year."

The grid operators plan to draft a report on the 2024/25 study's results by March 9 and then develop a business case and allocate costs. They have yet to agree on a single joint project during the more than 10 years of the FERC Order 1000-compliant CSP process, usually disagreeing over the cost-benefit analysis.

Stakeholders have until Feb. 6 to submit transmission issues for 2026 that could be system needs to either MISO or SPP. The RTOs' staffs will review the issues 2026 during a March 6 meeting.

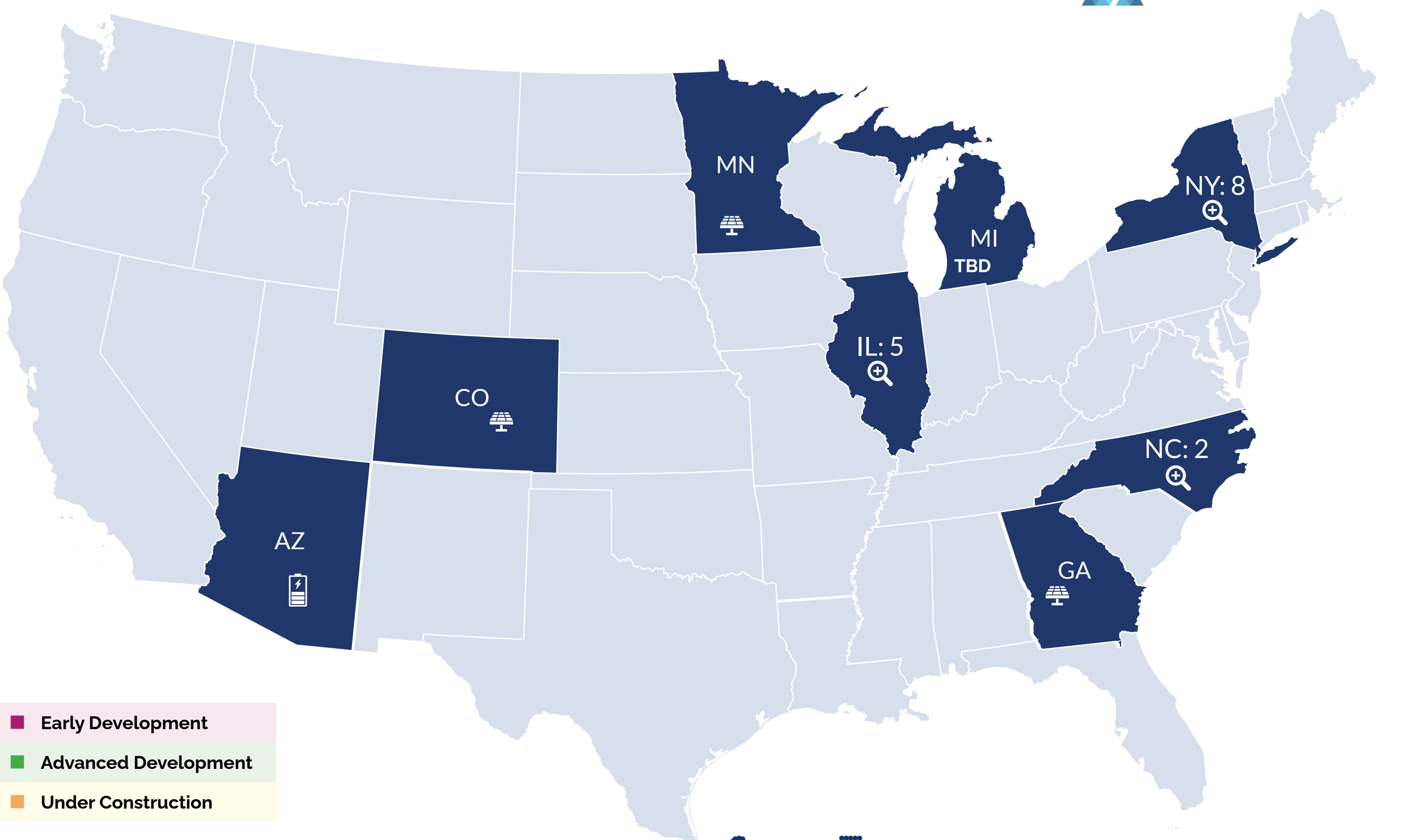
RTOE RRs on Consent Agenda

The unanimously approved consent agenda, with two clean energy members abstaining, included an update to the 2027 Integrated Transmission Planning sunset and RTOE transition's scope; an *RTOE trading hub analysis*; and the quarterly *in-service date delay report*. ■

This article has been edited for length.
Click here for the full version.

Generation Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

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

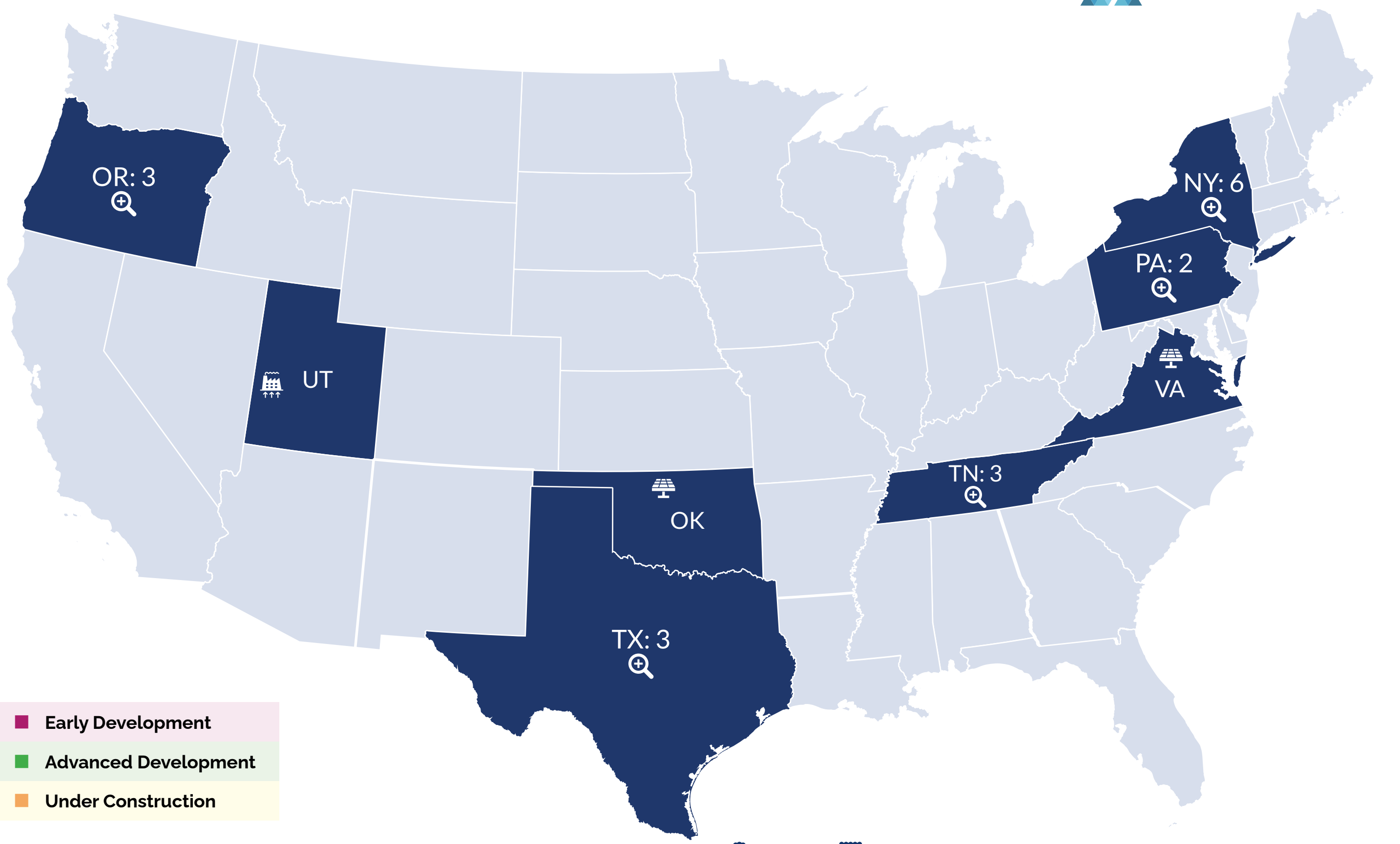
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Cactus Wren BESS	esVolta, LP		AZ	800	2028
	Waxwing Solar CSG WAXWI	Ownership Undisclosed		CO	3	2026
	Sandhills Solar 2	Leeward Energy		GA	200	2028
	10601 Seymour Ave East 2 PV1	Ownership Undisclosed		IL	2	2025
	Arlington 1 11238	Ownership Undisclosed		IL	5	2026
	Arlington 2 11239	Ownership Undisclosed		IL	5	2026
	Belicina Solar	Saxovent	Ironwood Projects	IL	4	2028
	Albion Solar BESS	Ecoplexus		IL	150	2028
TBD	**Hastings Generating Facility GEN1**	Ownership Undisclosed		MI	2	2026
	RP Minnesota Solar CONEJ	Ownership Undisclosed		MN	2	2026
	Craggy Energy Storage	Duke Energy Corp	Duke Energy Carolinas	NC	31	2026
	Eli Lilly Solar Park	Eli Lilly and Company		NC	5	2026
	Bartell South PV I BARTE	Ownership Undisclosed		NY	3	2026
	Blue Barns 11156	Ownership Undisclosed		NY	2	2025
	Broadlea 11155	Ownership Undisclosed		NY	5	2025
	Guyer 11165	Ownership Undisclosed		NY	4	2025
	Knox II PV KNOXS	Ownership Undisclosed		NY	5	2026
	Little Falls PV LITTL	Ownership Undisclosed		NY	3	2026
	Lodi I 11249	Ownership Undisclosed		NY	5	2026
	Lodi II 11250	Ownership Undisclosed		NY	5	2026

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

Generation Added in the Past Week

YES ENERGY



Early Development
Advanced Development
Under Construction

Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear Coal Hydro

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Lysander III PV LYSAN	Ownership Undisclosed		NY	2	2026
	Mallory South PV I MALL1	Ownership Undisclosed		NY	5	2026
	Mallory South PV II MALL2	Ownership Undisclosed		NY	5	2026
	Ingraham Solar	Sunwealth		NY	5	2026
	ELP Granby Solar II BESS	Vitol Holding B.V.	VC Renewables	NY	5	2028
	RPNY Solar 11	Renewable Properties		NY	5	2026
	Red Barn Solar	Total SA	TotalEnergies	OK	202	2027
	Burlingame Solar BG	Ownership Undisclosed		OR	2	2025
	Record Solar–Quincy	Hawthorne Renewable Energy		OR	80	2031
	Record Solar–Quincy BESS	Hawthorne Renewable Energy		OR	80	2031
	Middle Road Solar Partners HALIF	Ownership Undisclosed		PA	3	2026
	New Freedom Solar Partners NEWFR	Ownership Undisclosed		PA	3	2026
	Cumberland Combined Cycle ST 1	TVA	TVA	TN	323	2026
	Cumberland Combined Cycle ST 2	TVA	TVA	TN	323	2031
	Cumberland Combined Cycle CT 2	TVA	TVA	TN	455	2031
	DGS Five Points FPBAT	Ownership Undisclosed		TX	10	2026
	Plaza Street PSBAT	Ownership Undisclosed		TX	10	2026
	Spectra Solar	Softbank Group Corp.	SB Energy	TX	1,200	2030
	Cape Geothermal Power Plant 4	Fervo Energy		UT		2028
	Bluegrass Solar	Dominion Energy		VA	3	2028

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

Company Briefs

Toyota, Lightsource bp Agree to VPPA

Toyota and Lightsource bp announced a 15-year virtual power purchase agreement.

Toyota will purchase energy from Lightsource's 231-MW Jones City 2 solar project in Texas. Toyota Environmental Sustainability General Manager Tim Hilgeman said the agreement could cover more than 20% of the car maker's purchased electricity needs in North America.

More: *Renewables Now*

Google Taps Clearway for 1.2 GW of Carbon-free Power

Clearway Energy Group struck three deals with Google to supply the tech group with carbon-free power from 1.2 GW of capacity in Missouri, Texas and West Virginia.

The three power purchase agreements will support Google's data centers in the SPP, ERCOT and PJM markets for up to 20 years.

All plants are slated to enter the construction phase in 2026, with the first ones expected to become operational in 2027 and 2028.

More: *Renewables Now*

Federal Briefs

Congress Passes FY 2026 Energy Funding Bill

The U.S. Senate voted 82-14 to pass an Energy and Water Development appropriations bill that will fund the Department of Energy, Army Corps of Engineers and Bureau of Reclamation for fiscal 2026.

The bill appropriates just over $49 billion for DOE.

The House of Representatives passed the bill Jan. 8, and it is expected that President Donald Trump will sign it into law prior to the funding deadline Jan. 31.

More: *Holland & Knight*

2025 Among 3 Hottest Years on Record

2025 was the Earth's second or third-hottest year on record, several U.S. and global climate science organizations said.

The National Oceanic and Atmospheric Administration, as well as the EU's Copernicus and the U.K.'s Met Office, found that 2025 was the third-hottest year recorded. NASA found 2025 to be the second-hottest year, though the numbers were so close it was effectively tied with 2023.

The last three years are the three hottest the planet has ever faced, with 2024 being the warmest ever.

More: *The Hill*

State Briefs

COLORADO

Colorado Springs Utilities Changes Peak Hours Billing

Colorado Springs Utilities has enacted a new program that will charge customers different rates for energy used at different times of the day.

The utility will charge a higher rate for energy used during the peak hours of 5-9 p.m. during the winter and summer seasons. The winter peak charge will increase from 7 cents to 14 cents, while summer peak hours will jump from 7 cents to 29 cents.

More: *Colorado Public Radio*

IDAHO

Ada County Greenlights Solar-plus-storage Project

Ada County commissioners voted to approve a conditional use application for a 150-MW solar farm and battery storage facility just outside of Kuna.

Solar arrays will cover about 950 of the property's 1,700 acres.

More: *BoiseDev*

INDIANA

Bill Would Remove Eminent Domain Option for Pipelines

Rep. Tim Yocum (R-Clinton) has introduced legislation that would remove the use of eminent domain for private carbon capture, carbon pipelines and other underground carbon storage projects.

The bill was referred to the House Utilities, Energy and Telecommunications Committee. If the bill passes out of committee, it will move to the full House of Representatives for further consideration.

More: *WTWO*

IOWA

House Bill Would Ban Eminent Domain for Pipelines

A House subcommittee advanced a bill that would prohibit carbon dioxide pipeline operators from exercising eminent domain for the purpose of building a pipeline.

Rep. Steven Holt (R-Denison) said the bill would not stop the pipeline from being built but would protect residents' private property rights. Opponents of the bill argued it would stall economic growth by blocking construction of the Summit Carbon Solutions pipeline.

Holt advanced the bill to the House Judiciary Committee.

More: *Iowa Capital Dispatch*

SCOTUS Denies Rehearing Request in Summit Pipeline Case

The U.S. Supreme Court denied a request Jan. 12 from Story and Shelby counties for a review of a lower court's ruling that county ordinances pertaining to a carbon sequestration pipeline were preempted by federal pipeline regulations.

The lawsuit is between the counties and Summit Carbon Solutions, which is seeking to build a carbon sequestration pipeline across the state. In October 2022, county supervisors enacted local ordinances that established setback, permitting, emergency management and abandonment standards for hazardous materials pipelines within the counties. Summit sued the counties later that year, arguing the ordinances were preempted by federal pipeline safety standards.

The court did not offer an explanation for the denial.

More: *Iowa Capital Dispatch*

MARYLAND

Lawmakers Introduce Bill to Deploy 4 GW of Solar

Del. Lorig Charkoudian and Sen. Benjamin Brooks introduced the Affordable Solar Act on the opening day of the 2026 legislative session.

The bill would establish a target to connect 4 GW of solar capacity to the grid by 2035 and mandate that implementation result in no increases to utility bills for residents.

The legislation now moves to committees for hearings and fiscal analysis.

More: *pv magazine*

MASSACHUSETTS

Healey Admin Pushes Back Clean Heat Standard to 2028

Environmental regulators are delaying implementation of the Clean Heat Standard until 2028, according to a note the Healey administration sent to stakeholders in late December.

The memo, sent to "stakeholders" on Dec. 23, 2025, said the administration is "working to ensure there is a robust market for affordable clean heat" and the state will be evaluating additional data around fuel and emissions trends and heat pump adoptions.

The standard is a key part of the state's overall climate strategy and was expected to take effect in 2026. The Clean Energy and Climate Plan for 2025 and 2030, which was released in 2022, evaluated five different clean heat scenarios to identify "the most cost-effective way to meet statutory GHG emissions limits."

More: *CommonWealth Beacon*

NEVADA

NV Energy Won't Refund Full Amount to Customers

NV Energy, which has overcharged customers as much as $65 million since 2002, says it doesn't intend on making customers whole, according to a filing with the Public Utilities Commission.

The utility, which originally intended to pay back customers for six months of overpayment, is offering refunds back to June 2017, the last month for which it has records. PUC staff want customers made whole for all overcharges back to 2002, with interest, by estimating the overcharges preceding 2017. NV Energy claims the PUC would have to file a contested case, which "would significantly delay compensation to customers."

A law passed by the Legislature in 2025 requires utilities pay back all overcharges with interest.

More: *Nevada Current*