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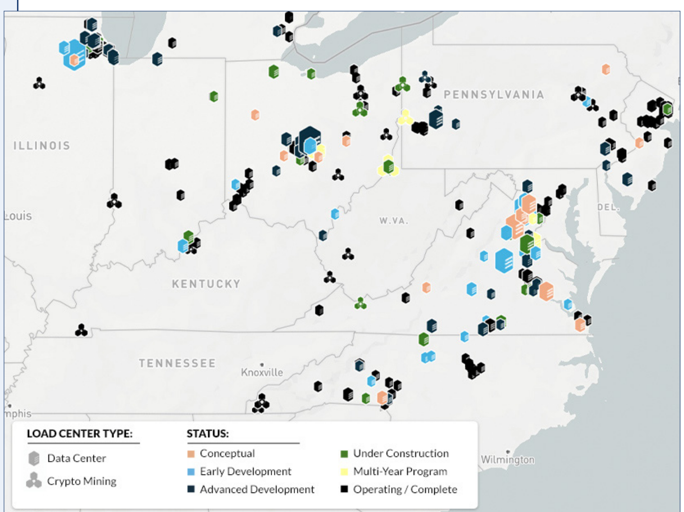
Parties Warn FERC that Jurisdictional Fight Could Slow Data Center Connection Effort



Yes Energy

Many commenters on the ANOPR from Energy Secretary Chris Wright cautioned that a jurisdictional fight between FERC and states over customer interconnections could actively work against the proposal's goal.

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Demand Response Should be a Priority in PJM's Large Load Approach (p.8)

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Whatever path PJM chooses, other markets may follow, meaning its decision could shape how demand response is used nationwide, CPower CEO Michael Smith writes.

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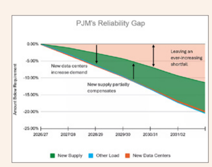

NRDC

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In this week's issue

Whither Nuclear?

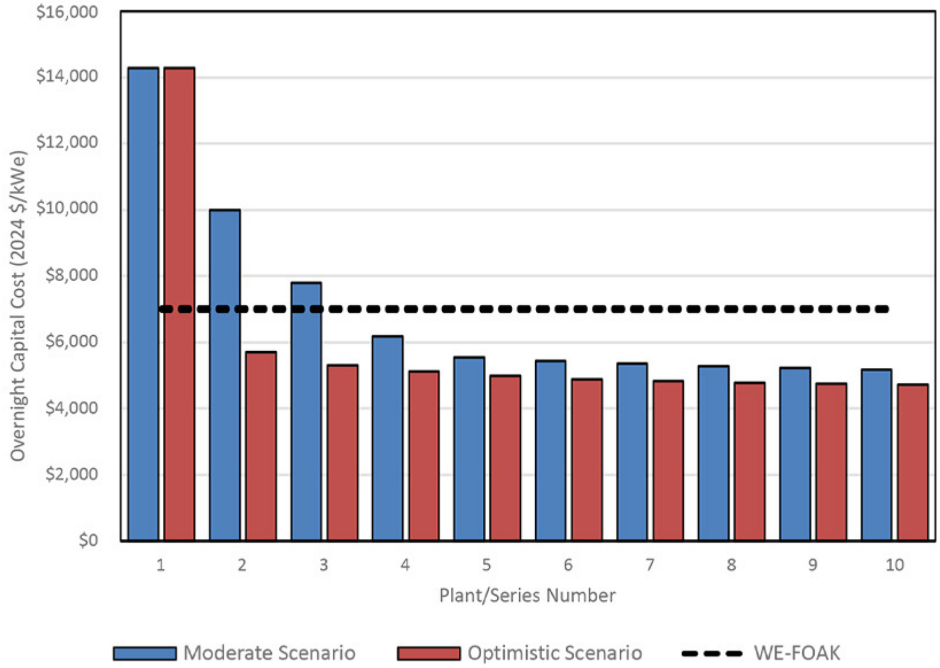
By Steve Huntoon

Steve Huntoon

As you know, Westinghouse, its two (Canadian) owners, and the U.S. government announced *plans* for $80 billion of investment in new nuclear plants. Recent articles are *here*, *here* and *here*.

I've been skeptical about new nuclear for many years — whether it be microreactors for U.S. military *bases*, new nuclear *generally*, small modular reactors in *Ontario*, nuclear *fusion* or Vogtle, as I wrote about *here* and *here*. And the skeptic's case remains *powerful*.

But a recent *study* from DOE's Idaho National Laboratory (INL) leads me to think this recent announcement could be a vehicle for something important.



Potential cost reductions for AP1000 deployments | *DOE*

The NOAK Unit

The INL study makes a strong case that the cost of new nuclear plants could decline from the Vogtle experience as multiple units are constructed, until reaching a "mature" ("nth of a kind" or NOAK) cost of around $6,000/kW at around the seventh to ninth plant. The projected cost reduction from Vogtle's $15,000/kW? About 60%. The chart from the study (see above) illustrates the cost reduction in terms of capital cost per kilowatt (a "series" is two plants).

You can read the study for the various drivers of the cost reduction.

The China Experience

The INL study bases much of its analysis on China achieving low and declining costs and construction times with its past completion of four AP1000 (Westinghouse design) units, and its 11 CAP1000 and CAP1400 units (adapted from the Westinghouse AP1000 design) now under construction, as listed *here*.

A separate Harvard *study* is featured in a recent *New York Times* *article*, with more color *here*. A chart shows capital costs for new Chinese projects under construction at around $2,000/kW.

This Chinese capital cost is about one-third of what the INL study says is possible in the U.S. This would suggest that the INL NOAK cost is not just whistling Dixie.

Cost of New Nuclear Versus Alternatives

So what would the INL NOAK cost mean relative to the costs of other electric power generation?

The chart on the next page from the INL study showing the anticipated U.S. cost reduction in $/MWh Levelized Cost of Energy (LCOE) terms in the context of other generation costs.

The nuclear range is shown with and without an investment tax credit (ITC). You'll see that with or without an ITC, nuclear costs start falling below firmed-up solar (based on Lazard estimates) after several nuclear units. And new nuclear cost falls within the broad range for new gas combined cycle cost (not to be confused with the very low cost of retaining existing gas units, even with carbon emission mitigation, as I've discussed *before*).

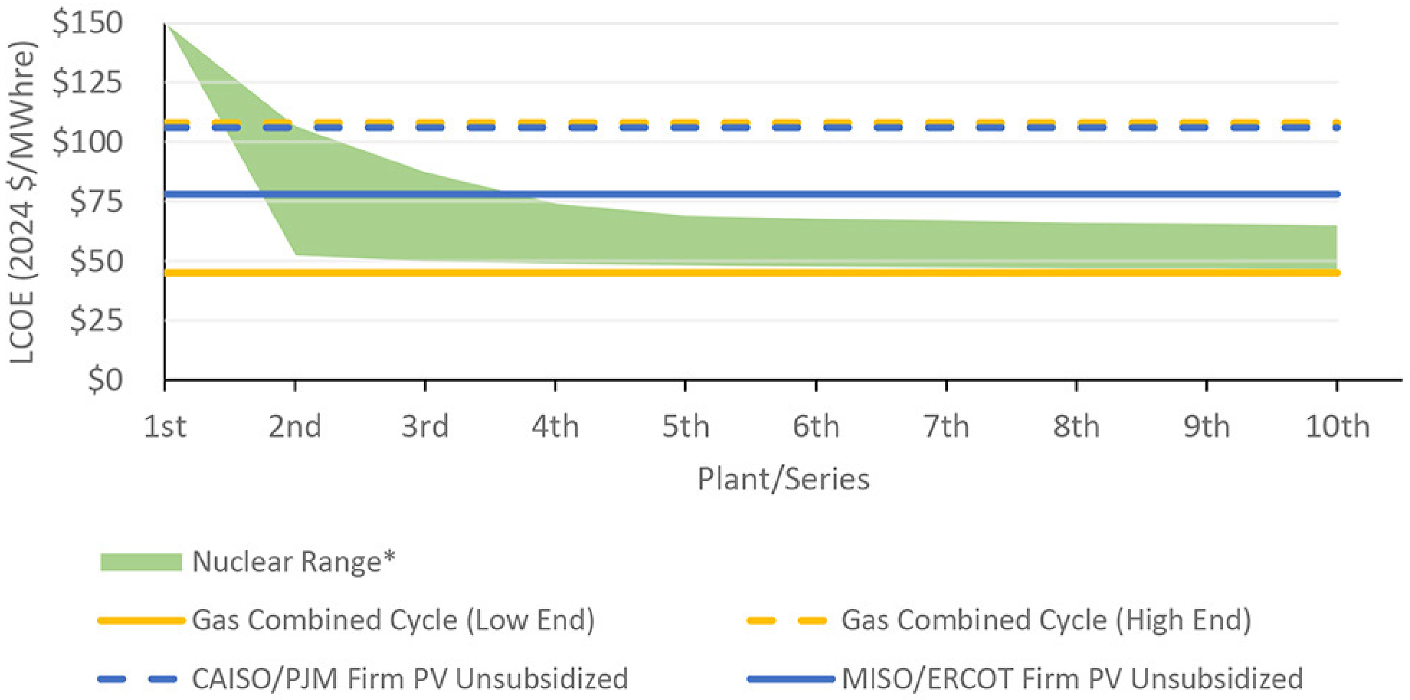
Importantly, these LCOE cost comparisons are before consideration of the social cost of carbon. If a social cost of carbon were incorporated, such as the $66/tCO2 discussed *here*, with a $/MWh equivalent of about $30/MWh, the above combined cycle costs would go up substantially. Another way of looking at it is to consider the social cost of carbon as roughly similar to the ITC financial benefit, so the social cost of carbon is rough justice supporting the ITC as an economically justified subsidy.

Location, Location, Location

The prior chart illustrates another important consideration. You'll note that firmed-up solar in MISO and ERCOT has an LCOE about $30/MWh less than firmed-up solar in CAISO and PJM. This illustrates Lazard's detailed *analysis* of the costs of firming up solar and wind, finding that LCOEs differ dramatically by region and by resource.

Given that solar and wind are much more expensive in some regions than in other regions, are the high-cost regions going to decarbonize if it means a permanent economic disadvantage? The only fix (absent nuclear) would be very expensive, difficult-to-site transmission to move power from low-cost renewable regions to high-cost renewable regions.

Nuclear is not location dependent. That could be important for high-cost renewable regions to reduce carbon emissions



Moderate scenario LCOE values: Representative of U.S. experience | *DOE*

at competitive cost.

Getting There from Here

So new nuclear might be competitive, but here's the rub: Who's going to put up \$14,000/kW for the first two units? Or \$10,000/kW for the next two? Absent taxpayer (or tech bro or foreign country) financial support, new nuclear can't get out of the starting gate.

We should recall that taxpayers footed the bill to get solar and wind going, starting almost 50 years with an ITC. EIA estimates that between 2016 and 2022, renewables received \$84 billion in federal taxpayer support, while nuclear received \$3 billion over *the same period*.

Assuming the INL capital costs, we can ballpark what it would take in taxpayer subsidies to buy down the cost of the first six nuclear units to the projected cost of the seventh unit (which yields an LCOE below firmed-up solar). Taking the cost differences and applying the 6,600 MW of six AP1000 units comes to \$30.8 billion.

Taxpayer funds could be provided over time to match a schedule for outlays. The first two to three pre-construction years for a given plant wouldn't require much *money*, but they would get the ball rolling.

An Elephant in the Room

Let me acknowledge a structural weakness in this plan: the creation of a monopolist, Westinghouse. Monopolies by nature raise prices and have limited incentive to be efficient, with poster child Vogtle as I've written before *here* and *here*.

But the situation here might be the exception to the rule if potential profits from future NOAK units, assuming price targets were achieved, were sufficient incentive for Westinghouse and its major vendors to contain costs on the subsidized first units. And the actual agreement could have financial features designed to incent cost containment.

The Actual Agreement

Regarding the actual agreement for the new initiative, one of Westinghouse's owners said it expects it to be done around the end of *the year*.

The details of such an agreement are critical to any chance of success. Who's doing what, when, how and where? What are the incentives to do what, when, how and where? Who's qualified to do what, when, how and where? Who's bearing the cost overrun and schedule delay risks of what, when, how and where? Who's independently monitoring what, when, how and where? What are the enforcement measures to ensure everyone does what they commit to do, when, how and where?

If the requisite engineering, finance, economic, commercial and legal expertise for such an agreement doesn't exist in the U.S. government, hire it from outside. There's too much at stake to wing it.

Bottom Line

There are three established sources of carbon-free electricity: solar, wind and nuclear (putting aside hydro with its limited expansion prospects). With staggering need for more electricity, are we going to give up on one of the three — the only one that is not intermittent and not locational? As Wayne Gretzky (actually his father) *said*: "You miss 100% of the shots you don't take."

Let's take a shot, America.

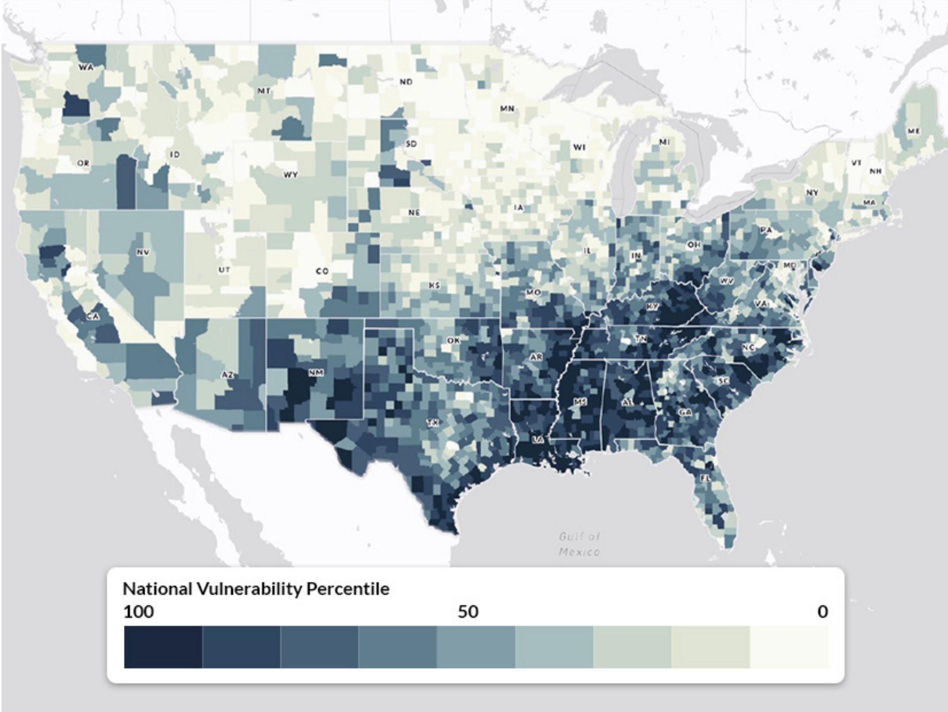
P.S. For the holiday season in these challenging times, here are some lists of *happy music* courtesy of some good folks on Maryland's Eastern Shore. And here's a classic *video* for the season by the Dropkick Murphys. The best of the holidays to you and yours! ■

Building a Resilient Grid for an Uncertain Future

By Dej Knuckey

Dej Knuckey

The grid was never designed for the world it's being asked to serve. Electrification is accelerating faster than planners expected; extreme heat is swelling peak demand; and climate-driven disasters are smashing records while breaking infrastructure.



County-level overall climate vulnerability | *U.S. Climate Vulnerability Index*

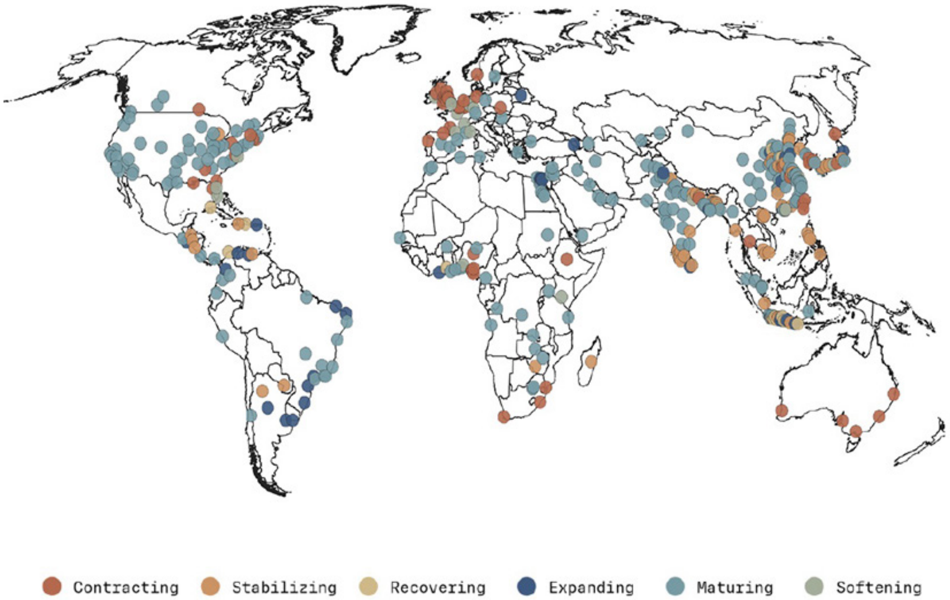
Yet the electric industry is expected to build a grid that can deliver reliable power to regions that may succumb to, survive or even thrive in a future further affected by climate change.

Planning for the grid of the future requires increasingly sophisticated prognostication, and the industry needs to look to new data sources for modeling. Climate scientists and economists have become as important as engineers, and traditional peak-demand forecasts and resource-adequacy models cannot capture the compound stresses facing today's grid.

Wayne Gretzky famously said he "skate[s] to where the puck is going to be, not where it has been." That's all very well if you know where it's going to be — difficult for a puck, even more so for a grid being expanded in an environment some call a *polycrisis*.

Utilities and regional planners no longer can rely on models built for a more stable, predictable climate, one that no longer exists. To build a grid that is both reliable and resilient, planners now need modeling tools that integrate growth patterns and climate risk. The next generation of modeling — probabilistic, scenario-based, climate-informed — is not simply an upgrade. It's becoming the minimum requirement for any utility, regulator or investor hoping to keep pace with the world in which the grid must operate.

A new measure launched in November by the First Street Foundation may prove a critical tool for understanding the intersection of climate risk and economic growth.

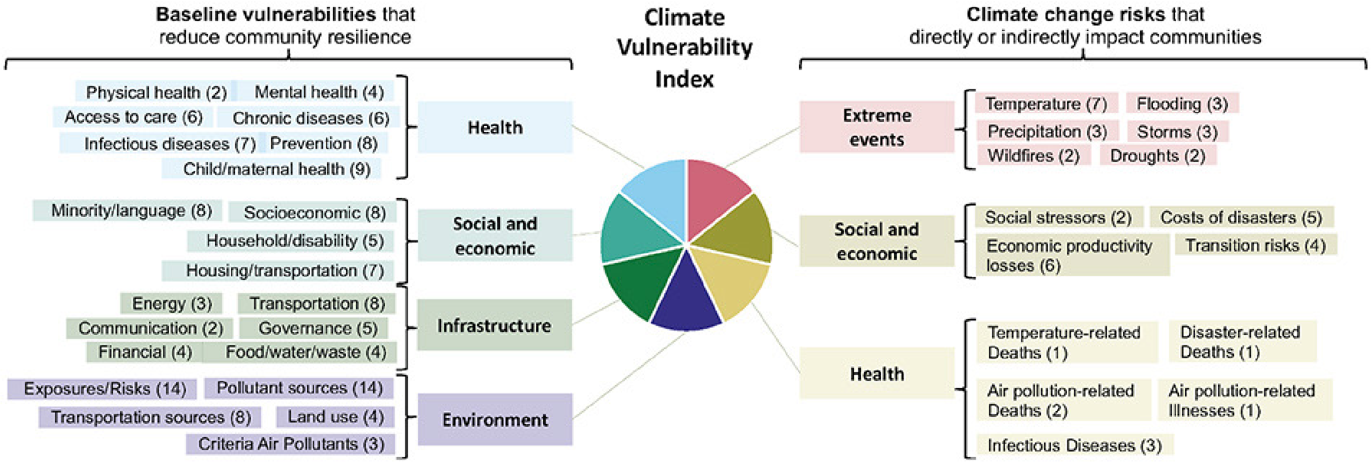


Resilience spread growth trajectories across global cities with 1 million or more residents | *First Street*

Understanding Resilience Spread

Resilience Spread, a concept coined by First Street, captures the intersection of two opposing forces, like Dr. Doolittle's fictitious *Pushmi-Pullyu*, a double-headed llama that tries to move in two opposite directions at once. In one direction, there are positive market forces, reflected in population growth, economic strength and amenities such as housing and transportation. In the other direction, there are negative climate risks.

The Resilience Spread quantifies the gap between a region's climate exposure and its ability to adapt. It's a gap that is widening in many areas, creating a patchwork of vulnerability. Looking at 400+ of the world's major cities, First Street determined that economic strength is outweighing climate risk by a massive $1.8



Climate vulnerability is a function of both community resilience and climate change risks. | *U.S. Climate Vulnerability Index*

trillion globally, which "illustrates that, on average, strong macroeconomic conditions and consumer confidence continue to offset the drag of climate hazards," the report said.

But the average is meaningless for planners. What's important is how individual cities are expected to perform, and that ranges widely. And there's also the factor of time. While today's global spread is net positive, "this cushion is not permanent. Without significant adaptation, the spread is projected to erode steadily, tipping negative before the end of the century as climate pressures intensify faster than foundational macroeconomic conditions."

The speed at which we lose the economic buffer depends on how we invest in adaptation. The firm predicts that unless those investments are substantial, the global spread will be eroded fully by 2085, "as intensifying hazards outpace resilience."

The Many Faces of Climate Risk

Climate risk comes in many flavors. The *U.S. Climate Vulnerability Index map*, developed by the Environmental Defense Fund and Texas A&M University, drills down on the various climate risks and impacts in each county or census tract. It maps extreme events, such as storms and droughts (see our series on the effects of extreme climate events on the grid: *fire*, *flood* and *heat*), as well as impacts such as heat-related deaths and other factors such as air pollution and socioeconomic stressors.

The index accounts for an essential piece of the resilience equation: If an area already is struggling, it is less likely to withstand the challenges posed by climate change.

Why This Matters

The competing forces of market strength and climate vulnerability vary within different areas, and advanced modeling is needed to keep up with those factors, writes Dej Knuckey.

First Street distinguishes between chronic and acute risks: "Chronic risks reflect long-term, gradually intensifying physical climate stressors such as heat, drought or sea level rise, while acute risks capture short-term, high-intensity events like floods, storms or wildfires."

For grid planners, chronic risks are easier to plan for, and the grid can be hardened to resist them in advance, but acute risks are more likely to damage significant portions of the grid, providing the opportunity to rebuild in a more resilient way.

Growth in All the Wrong Places

Why, in a world where we've known for a few decades that climate change will adversely affect major economic centers on the coasts, are some of the biggest economic centers also the most at risk of climate damage? Because many of the biggest cities were located at trading hubs, which historically were at deep ports. First Street found what it called a "striking paradox." Of more than 400 major global cities, "over half of global urban GDP is concentrated in places facing the highest levels of acute climate risk."

A city's attractiveness as a place to live and do business can survive high climate risk, according to First Street. "Many of the world's most economically productive cities remain hubs of growth despite sitting in the top quartile of acute risk."

Miami is an example of a city that is both one of the world's most productive, high-growth cities and among the most exposed to climate events, such as sea-level rise, heatwaves and hurricanes. Despite being in the top percentile of climate risk, its economic strength is buoyed by amenities ranging from a strong labor market to the desirability of living near wide sand beaches.

In cities like Miami, where the market effect outweighs the climate effect, First Street's resilience spread is positive.

"These positive spreads imply that markets potentially undervalue their opportunities relative to climate risk, highlighting a hidden upside, as capital inflows remain strong and long-term attractiveness endures." For planners, that resilience spread can be used as a factor to adjust growth models upwards.

They also caution that the spread today is looking forward from one point in time. "Resilience is not fixed. Cities that thrive today may falter tomorrow if climate risks intensify … and begin to outpace the economic foundations that support their growth."

New Orleans is an example of a U.S. city where the market effect is lagging the climate effect, leading to a negative resilience spread. | *Dej Knuckey using data from First Street*

When the Resilience Spread is Negative

On the other end of the spectrum, a negative resilience spread occurs when the negative climate effect exceeds the positive market effect. "Climate risks' impact on location desirability already outweighs local economic strengths in roughly 30% of global cities today," First Street found.

New Orleans is an example where its role as a strategic port and its cultural significance fail to counterbalance the impact of its exposure to acute climate risks, most notably hurricanes and the resulting flooding.

Repeated extreme storms, including Hurricanes Katrina in 2005 and Ida in 2021, "have driven steady population decline, unaffordable insurance rates and insurer withdrawal, resulting in a deep negative resilience spread of -10.3%," First Street said.

For cities such as New Orleans, grid planners face a difficult calculation: how much to invest in the grid's resilience where climate threats are substantial and population is declining.

There is a risk that a deep understanding of climate risk modeling will lead to inequity. When there are so many competing capital investment demands, it can be tempting to deprioritize regions with weak adaptive capacity where any investments face greater risks from climate damage or economic decline. Yet those areas may depend most on investments today to withstand future challenges. Until there are discussions about *managed retreat* from the most climate-vulnerable areas — a topic few political leaders are willing to touch — policies must support the vulnerable communities as well as the well-resourced areas.

System Strength and the AI Demand Growth Wild Card

The market effect and climate effect are just two of the plethora of factors that planners need to consider. Infrastructure fragility — the ability of each part of the grid to withstand acute and chronic climate risks — is another key variable that will be the topic of a future column. And population trends also are key in a time of increased climate migration.

Perhaps the largest factor outside of climate change that is complicating grid planning is the rise of data centers, especially AI data centers, which weren't foreseen only a decade ago. It has moved forecasts that had been flat to negative into positive territory. *S&P Global Commodity Insights* anticipates U.S. electricity consumption "to grow at a compound annual growth rate of more than 3% from 2025 to 2030, with generation in tow."

That demand is not spread evenly throughout the country but is lumpy with intense localized demand in the areas where they are being built. Northern Virginia is the poster child for unexpected load growth, with 70% of global internet traffic carried by the more than 200 data centers in the county, according to *Oxford American*. As *RTO Insider columnist* Peter Kelly-Detwiler pointed out recently: "These facilities are large (often well over 100 MW), disconnected from the general macroeconomic environment and extraordinarily difficult to forecast."

Investing in Foresight

With so many competing factors shaping the grid of the future, utilities, ISOs and regional planning entities will need to invest in data infrastructure and modeling capabilities, building internal capabilities and accessing external expertise as needed. A key part of this will be ensuring acute and chronic climate risks are understood and accounted for, both in cities and rural areas, and in high-risk and high-growth areas.

The competing forces of market strength and climate vulnerability vary within any territory served by each utility, grid operator or policy body, and there's no single approach to planning that serves communities at opposite ends of the resilience scale. But all areas will be served better by industry and policy leaders who insist on, and invest in, advanced modeling.

Without smart, sophisticated modeling, planners will be flying blind — and costs, blackouts or inequities will be the price. ■

— Power Play columnist Dej Knuckey is a climate and energy writer with decades of industry experience.

Demand Response Should be a Priority in PJM's Large Load Approach

By Michael D. Smith


Michael Smith

Given PJM's distinction of being both the nation's largest wholesale electricity market and the epicenter of the data center boom, many hoped the grid operator would move closer to approving reforms governing large loads after a full day of committee proposals on Nov. 19. However, none of the dozen proposals considered were approved. (See *PJM Stakeholders Reject All CIFP Proposals on Large Loads*.)

The voting results suggest that an approach similar to PJM's proposal may be on the horizon. As a demand response aggregator and virtual power plant platform, CPower would be supportive, assuming certain provisions from PJM's proposal were to be implemented.

Regardless, we'd prefer PJM take the time to get large loads right rather than push through changes that could do more harm than good. PJM needs every megawatt of supply it can secure, and the last thing it should do is inadvertently force existing supply out of the market. With roughly 8 GW of DR in PJM, a poorly executed policy shift risks undermining a critical source of capacity.

As it stands now, with new large loads coming online, commercial and industrial customers are likely to be dispatched more frequently, meaning manual load shedding is likely to become more common. In time, this could discourage the largest customers from providing the greatest load relief through DR participation, which has proven to be instrumental in maintaining system reliability during peak events and preventing deeper emergency actions in PJM.

RELATED VIEWPOINT:

See related opinion: *PJM's Board Must Protect the Grid*

Why This Matters

Whatever path PJM chooses, other markets may follow, meaning its decision could shape how demand response is used nationwide.

| Shutterstock

If new large loads do not bring their own capacity, be it generation or demand flexibility at their site or elsewhere, the number of potential or actual reserve shortage hours over the next few years will rise to the point that PJM may routinely have hundreds of hours of DR calls.

With this in mind, we encourage the PJM Board of Managers to respect the following principles as it further deliberates reforms:

- "Non-Firm Goes First." New large loads that are not backed by DR or generator capacity have not purchased firm service and should be dispatched off the grid before pre-emergency DR providers.
- DR is DR. New large loads participating in load management programs should be dispatched at the same time as pre-emergency and emergency DR and price responsive demand, not after.
- DR Loads are DR Loads. Any new DR programs should be available to all customers, not just new large loads.
- Capacity is Capacity. If data centers can buy capacity from a generator to meet a requirement, they should be able to purchase DR capacity for the same purpose.

Whatever path PJM chooses, other markets may follow. That makes this decision especially consequential, as it could set a precedent for future policies and shape how DR is used nationwide.

Getting it right and expanding the use of DR is essential, as it's the most immediately available, affordable and reliable way to support rapid load growth and enable the innovative energy economy. ■

— Michael D. Smith is CEO of CPower, a virtual power plant platform with 6.7 GW of customer capacity at more than 23,000 sites.

PJM's Board Must Protect the Grid

By Tom Rutigliano and Claire Lang-Ree

Claire Lang-Ree

Load growth beyond PJM's ability to serve is a clear and present danger to the reliability of the grid and the functioning of PJM's markets. After stakeholders tried and failed to meet this challenge, it falls on PJM's board to solve.

Tom Rutigliano

The politics around this are complex, but the answer is clear: The board's duty is to protect the power grid and the 67 million people who depend on it. This requires decisive action. Putting off the problem or relying on hope are not options. (See *PJM Stakeholders Reject All CIFP Proposals on Large Loads*.)

The sudden explosive growth of data centers might promise to add more load every year than PJM has added in the past 20. Persistent yearslong delays in getting new electrical generation online due to difficulties with the queue, supply chains and construction leave a sobering outcome.

PJM will barely meet reliability standards in 2026 and almost certainly *will fall below* them in 2027. The capacity market is pegged at its price cap with no prospect of relief. While the flood of new data centers overwhelms the trickle of new generation, things will only get worse.

In a way, the dire situation makes the board's decision easy. The only way to keep PJM reliable is to hold back the flood. There are a few ways to do that.

Possible Solutions to Demand Growth

The Independent Market Monitor has proposed the direct approach of not letting data centers connect to the grid until supply is available.

Others, including NRDC and 50-plus state *elected officials*, have taken a softer approach: Let states decide if data centers can connect, but if they add demand faster than capacity, they will be first to be turned off in an emergency. (See *Regulators Urge FERC to Honor State Authority over Large Load Interconnections*.)

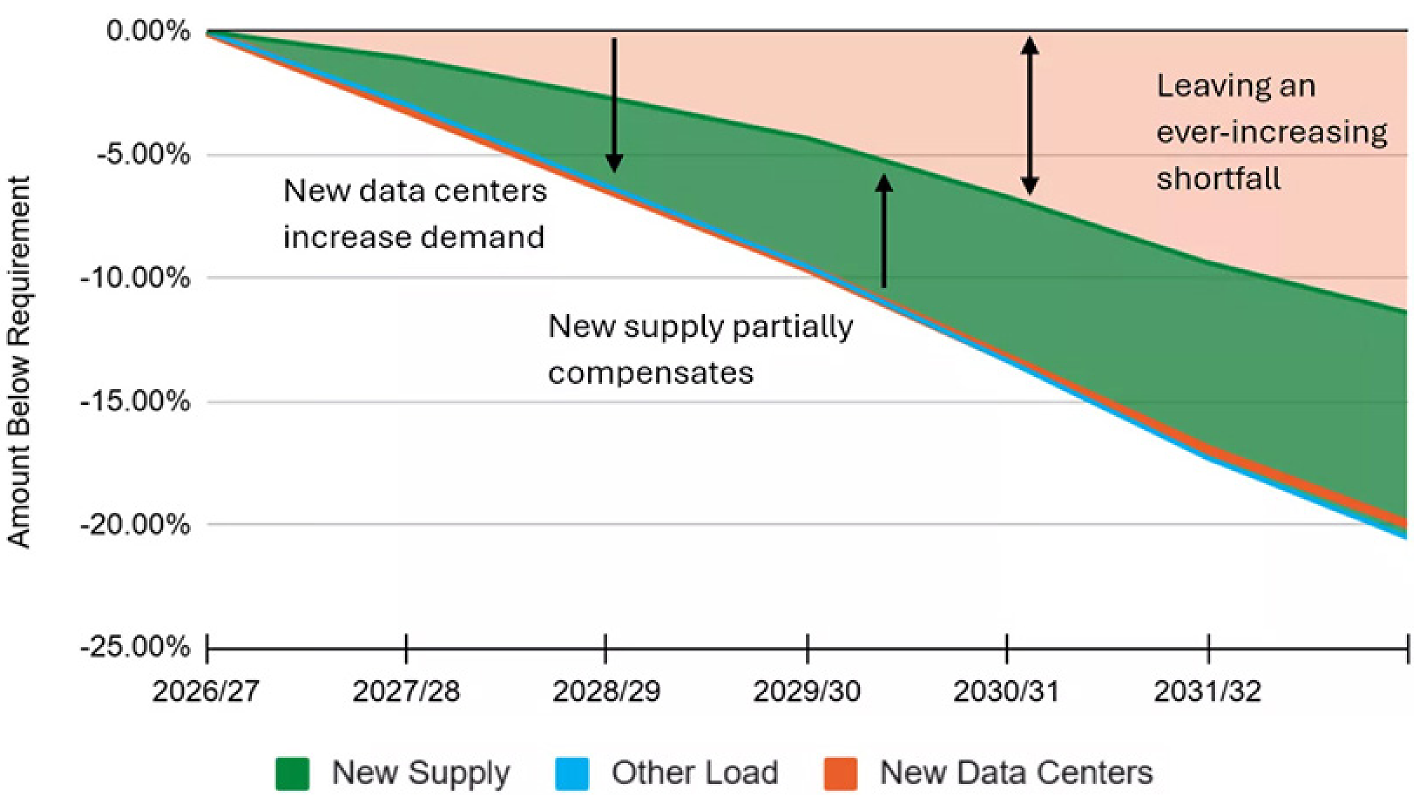
Whichever solution the board chooses first and foremost must prepare for the possibility PJM won't have enough power

RELATED VIEWPOINT:

See related opinion: *Demand Response Should be a Priority in PJM's Large Load Approach*

Why This Matters

There are 67 million people who rely on PJM making independent, objective decisions, even when those are unpopular or painful to some. Now is the board's chance to justify this confidence, says the NRDC.



PJM's reliability gap | *NRDC*

to promise it to everyone who wants it. Physics leaves no room for compromise.

Other proposals before the PJM board have helpful components. State governors proposed a package of incentives for data centers to support the grid. Many point to the old bugbear of speculative data centers in the hope that more rigorous forecasts can shrink the problem.

These are encouraging, and we hope they work out. But these are just hopes. Hope may be the currency for poets and politicians, but it's poor coin for engineers and economists. While the board should support every fair chance for a positive outcome, its duty is to prepare for the worst.

Capacity Price Relief Needed

The PJM board's solution must include capacity price relief. The prices coming out of the reliability pricing model (RPM) right now serve no purpose. Thanks to delays, high prices won't stimulate new entry in reasonable time frames. Nor are high prices needed to prevent retirements.

We're coming off a six-year run of prices under $200/MW-day. It's silly to argue that plants will retire if they can't get paid double that. No matter what RPM does, any power plant that can make a spark should be able to name its price to tech companies.

The capacity market is being asked to do a job entirely outside what it was designed for, and it's failing in a way that transfers tens of billions of dollars from the public to lucky generation owners who already were comfortably profitable. Those owners should be thinking about geese and golden eggs.

Avoid Two-tiered Queue System

One thing the PJM board should not do is enable any kind of fast track for new generation that harms projects that already are waiting in the queue.

For many years, PJM has been telling projects — including some required by state law or supported by federal policy — to wait in line. It would be unconscionable for PJM to reverse itself now and let projects that support data centers jump to the front of that line.

This threatens to create a permanent two-tier interconnection system, with one level of service for power plants that support data centers and second-class service for clean energy. PJM stakeholders rejected those concepts, perhaps remembering that open access and fair competition are one of the reasons PJM exists in the first place. The board should do the same.

There's still room for improvement on interconnection. ERCOT has kept up with the data center boom in Texas in part thanks to their "connect and manage" approach, where new power plants join the grid as-is, accepting the risk that sometimes the transmission system might not be able to deliver their power. PJM should consider reforms like this. But no matter what PJM does on interconnection, no state should tolerate its clean energy laws being treated worse than tech companies' commercial interests.

PJM requires independence from its board members. Nobody with conflicts of interest that could influence their objectivity is even eligible to serve.

This is for good reason. The board makes final decisions on vital issues for the power grid, often with billions of dollars at stake. There are 67 million people who rely on PJM making independent, objective decisions, even when those are unpopular or painful to some. Now is the board's chance to justify this confidence. ■

— Tom Rutigliano is senior advocate and Claire Lang-Ree is advocate for the Sustainable FERC Project at the Natural Resources Defense Council.

Parties Warn FERC that Jurisdictional Fight Could Slow Data Center Connection Effort

By James Downing

Why This Matters

Many commenters on the ANOPR from Energy Secretary Chris Wright cautioned that a jurisdictional fight between FERC and states over customer interconnections could actively work against the proposal's goal.

A common theme across the deluge of comments on the Department of Energy's Advance Notice of Proposed Rulemaking to FERC on large load interconnections was that parties welcomed the process as a vehicle for the commission to improve its rules to help with speed-to-market concerns (RM26-4).

But many of the comments warned FERC and DOE from going too far into jurisdictional issues that could wind up working at cross purposes with the ANOPR's goal of speeding up interconnections. The first round of comments on the proposal was due Nov. 21. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

"Any commission action must recognize that large load customers are end-use retail customers, meaning the delivery service they receive necessarily includes an element of local distribution service," the Edison Electric Institute told FERC. "Even in states that have elected to restructure their electric industry and implement retail choice, the states require that local utilities secure wholesale transmission service on behalf of all retail customers so that they can procure this competitive generation supply."

The fair and rapid interconnection of large loads can be achieved without calling into question the way that states and FERC have traditionally regulated bundled service, the organization said.

"States have successfully regulated retail interconnections for decades, including interconnections of large retail loads, and upsetting that paradigm here may have unintended consequences that could undermine the goals of both EEI members and the commission regarding developing methods to ensure rapid and reliable connection of large loads," EEI said.

The ANOPR cites *EPSA v. FERC* as part of the justification for FERC to claim jurisdiction over large loads. In that case, the Supreme Court found that the commission could regulate areas that impact wholesale markets it oversees. But EEI said that decision left intact the Federal Power Act's savings clause in Section 201, which reserves authorities for the states.

"A court may find an argument that retail customers affect wholesale prices simply because they interconnect to the grid as a clear overreach by the commission," EEI said.

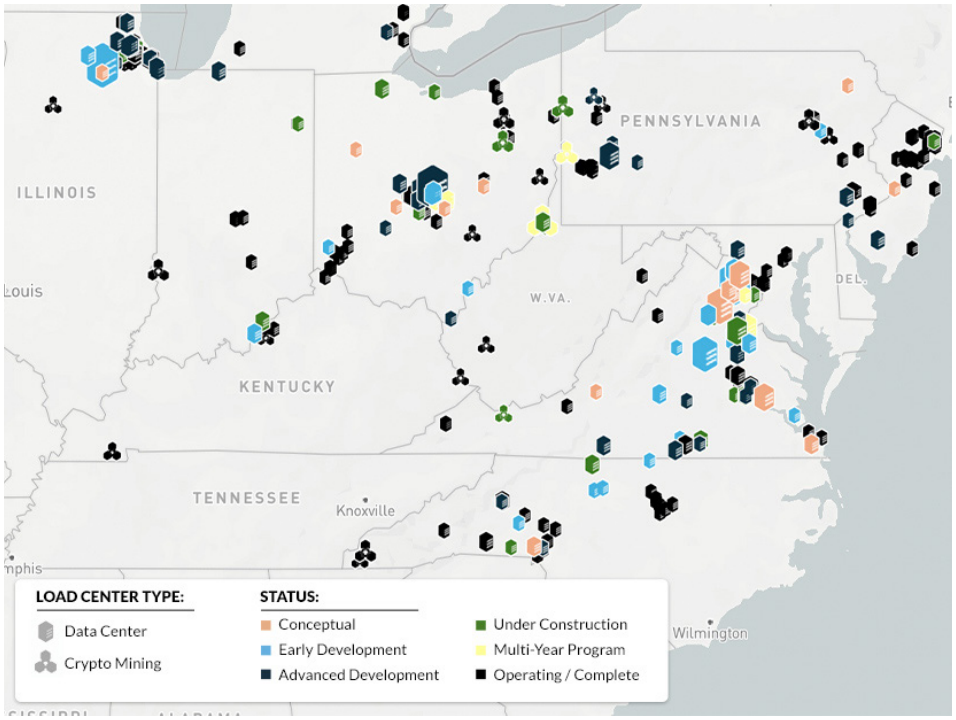
The National Rural Electric Cooperative Association filed similar comments, saying the ANOPR can help by focusing on issues firmly under FERC's jurisdiction, but any rule changes should avoid a jurisdictional fight.

If FERC does decide to go forward with asserting jurisdiction, it needs to foreswear jurisdiction over retail sales — even for large loads that connect directly to the transmission system, NRECA argued. The proceeding cannot be a backdoor to impose retail competition on states that are vertically integrated, it said.

"In considering whether to act upon load interconnection processes, the commission should keep core federalism principles at the forefront of its decision-making," the American Clean Power Association said in its comments. "Load interconnection has historically been a state-jurisdictional issue, and any federal action should be measured and carefully considered."

FERC could set clear requirements for consistent, timely and transparent load and hybrid interconnections, and then only trigger federal action if and when states and transmission owners cannot keep up with the minimum standards, ACP said.

The Virginia State Corporation Commission, which regulates the largest data center market in the world, made similar



| Yes Energy

comments.

"Under this paradigm, the transmission owners would file with the commission verification that a large load interconnection tariff meeting such requirements has been filed with their state regulatory authority," the SCC said.

The SCC noted that the ANOPR's claims about "connecting directly" to the transmission is questionable because almost all such loads have one or more substations on site to step down the voltage before the electricity can be used.

"The legal durability of any final rule in this proceeding will thus depend on the merit of these assertions," the Virginia commission said. "The VSCC does not believe it is necessary for the commission to even reach these questions, however, as the best approach to these issues is a cooperative one, where the commission sets minimum standards for interconnecting utilities to meet, while leaving it to state commissions to regulate these retail tariffs as they have done for many years."

The National Association of Regulatory Utility Commissioners argued that nothing in the ANOPR is intended to assert jurisdiction over distribution interconnections, generation facilities and retail sales, and the commission should explicitly state that in any final rule.

"As acknowledged in the ANOPR, FERC has never attempted to assert jurisdiction over end-user load interconnections," NARUC said. "The reason for this fact is that FERC asserting jurisdiction over load interconnection is outside the boundaries imposed by the FPA."

If FERC were to assert jurisdiction over the interconnection of a subset of retail customers, it would interfere with the balancing performed by state regulators in retail rate cases and would have significant impacts on all classes of customers.

"NARUC pledges to engage with regulated entities and other stakeholders to explore consensus solutions for FERC's consideration that will help meet national goals for large load interconnection, while avoiding disputes over jurisdiction that would impede achieving our shared goals," it told FERC. "Working together, under the concept of cooperative federalism, will lead to optimal solutions."

FERC can and should regulate large loads' interstate transmission and wholesale market aspects, the Pennsylvania Office of Consumer Advocate and the Delaware Division of the Public Advocate said in joint comments.

"Due to the resource adequacy and affordability crises that residential consumers face within PJM, the joint consumer advocates support all jurisdictional efforts to effectuate the FPA's plain text and core purposes as well as cost-causation principles," they said. "Primarily, the joint consumer advocates support the creation of an expedited large load interconnection queue that includes the large load through its interconnecting utility or electric distribution company, with a workable study time frame, that seriously accounts for participants' costs to all other affected grid users within the wholesale market."

The consumer advocates argued that the ANOPR ignores the fact that even very large customers are often connected through distribution facilities that are firmly under the states' authority.

"FERC should avoid pre-empting existing state authority because courts no longer reflexively defer to agencies' interpretations of ambiguous statutes, and *Skidmore* deference will not suffice here," the advocates said. "A FERC final rule that includes federal pre-emption of any existing, traditional state authority will face an uphill battle under the U.S. Supreme Court's new standard of review for agency statutory interpretation."

The ANOPR compares large load interconnections to the process FERC has long overseen for generators, but the Maryland Public Service Commission argued that the two are far different in reality.

"FERC issued Orders 888 and 2003 to correct inefficiencies and discrimination by vertically integrated utilities favoring their own generation resources," the PSC said. "However, utilities have no comparable incentive to discriminate against large load, as these customers represent valuable opportunities for new retail sales and investment. And unlike generators, end-use customers are retail customers — they do not participate in the wholesale markets."

Still, like many commenters, the PSC said that FERC can help speed up data center interactions through a policy of cooperative federalism.

The R Street Institute generally supports the expansion of wholesale and retail competition, but it said the fast-paced ANOPR process was not the right venue.

"FERC should narrowly address large load interconnections in ways that hew to the commission's well supported implementation of generation interconnection planning and that limit regulatory creep," R Street said. "FERC should further leverage the commission's competencies and expertise and prioritize litigation risk and implementation concerns."

What should FERC do in response to the ANOPR?

PJM said a federally regulated large load interconnection process warrants more study, but it urged FERC to move forward on areas where it has firmer jurisdictional footing, such as resource adequacy, ancillary services, interconnection and transmission planning, and NERC reliability requirements.

"Such a construct would have potential benefits including centralization and the promotion of uniform policies and practices," PJM said. "But, as with the existing generator interconnection process, there will undoubtedly also be costs, claimed delays (many of which will be outside the control of the RTO/ISO), and other complexities that will have to be addressed and that are likely to frustrate the ANOPR's 'speed to market' objective — especially given potential impacts to the existing generator interconnection process."

The RTO also asked FERC to move forward on the pending co-location proceeding that has held up large load issues in its footprint, as did other commenters who do business in its territory (EL25-49).

MISO supports rule changes to help speed up interconnections, but it argued that FERC should respect regional differences.

"MISO's existing processes effectively reflect unique facts and circumstances of MISO's system, its states and members," the RTO said. "Importantly, states and load-serving entities are primarily vertically integrated and responsible for resource adequacy within the MISO footprint. As a result, many states and utilities within MISO have processes which enable them to review and pare through speculative load requests to determine projects with more certainty, allowing MISO processes to enable speed to power for more certain large load interconnections, including determining the associated transmission required to facilitate the required generation interconnections."

Making large load use the same or a similar process to the generation queue, which has had its own well documented issues with delays, is also questionable, the RTO said.

"MISO questions whether standardized large load interconnection procedures will result in the 'speed to power' that is necessary to allow the United States to effectively compete in the global competition for economic development, such as in artificial intelligence and creating manufacturing and industrial jobs," it told FERC.

Meta, the parent company of Facebook and a major player in building data centers, also cautioned FERC against a one-size-fits-all approach, even though large load interconnections could benefit from some standardization.

"Some regions of the country are just beginning to bring data centers online, while others have already interconnected substantial large data center loads and are working quickly to add more," Meta said. "Keeping this momentum going is imperative. Issuing a detailed, standard rule that fails to account for the diversity in the economic landscape could slow down successful interconnection processes and undermine the commission's goal of bringing more data centers online faster and in a more orderly manner."

Amazon Energy — Amazon's energy trading subsidiary — supports FERC action, but whatever the commission does should not upset the planning around data centers that is already underway.

"Amazon Energy respectfully urges the commission to apply any new rules or policy changes adopted in this proceeding prospectively, and not to large load interconnection requests currently in progress under existing interconnection procedures," it said. "Specifically, Amazon Energy proposes any new rules apply only to large load interconnection requests that, as of the effective date of the new rules, have not executed agreements that include a significant financial commitment to the interconnecting utility."

Talen Energy's Susquehanna Steam Electric Station located in Salem Township, Pa. | *Talen Energy*

Google filed comments arguing FERC should work to build out the grid so the growing demand from data centers can be met in a timely and reliable way.

"Now is the moment to right the ship and build out the transmission grid needed to support our nation's ambitious AI goals," Google said. "And we must do this with a commitment to affordability: The goal is not to spend more, but to plan better in order to develop a transmission grid that can support the nation's digital infrastructure needs. Ultimately, a modern, robust transmission grid is the essential platform for delivering affordable, reliable energy to all customers, unlocking transformative dividends across the American economy — from AI leadership to a revitalized domestic manufacturing base."

The grid needs a holistic planning process, and grid planners need an accurate sense of how much new demand from large loads they will have to meet. Google endorsed SPP's Consolidated Planning Process, in which generator interconnection and long-term transmission planning are combined.

"The commission should also focus its near-term efforts on identifying pathways to expediting other transmission-level load interconnections that benefit the grid, such as loads that voluntarily offer flexibility via demand reduction or agree to take curtailable transmission service," Google said. "As with co-located or electrically proximate pairs of load and generation, Google believes that the commission should consider prioritizing reforms to expedite the study of loads that can themselves minimize or help manage the strain on the transmission system."

Flexibility's Role

Emerald AI, which works with data centers to make their operations more flexible, endorsed the ANOPR's idea to create a "Flexible Load Fast Track" for projects that can curtail demand when needed.

"The greatest opportunity in this rulemaking is not merely streamlining the administrative study process but enabling large loads to actively avoid or defer massive grid and energy infrastructure upgrades," the company said.

The traditional model in which new customers' load is measured at its maximum and coincident with system peaks requires major investment in new wires and generation and is fundamentally incompatible with the exponential growth and unique physical characteristics of data center demand, Emerald said.

"Delays in interconnection, driven by study processes that do not allow for flexibility — including software-defined flexibility — threaten to stall this economic engine," Emerald said. "By adopting a technology-neutral, performance-based definition of flexibility and curtailable load, the commission can unlock tens of gigawatts of capacity, ensuring that the U.S. maintains its competitive edge in AI while protecting ratepayers from the costs of unnecessary transmission buildout."

Non-firm Interconnection Service

American Electric Power commended DOE for launching the rulemaking and said FERC needed to ensure that generation can come online in a timely fashion to serve new large loads. It endorsed the connect-and-manage approach used in ERCOT.

"Under this approach, all generators pay an entry fee and can rapidly connect to the grid, subject to curtailment until supporting network transmission is planned and constructed," AEP said. "Generators may start as energy resources for some portion of their capacity but are on a pathway to full recognition as capacity resources until supporting network transmission is built."

The Data Center Coalition also endorsed a change to interconnection service, arguing FERC should regulate energy resource interconnection service more like ERCOT does with connect and manage. Too often, the organization argued, the commission has stringent requirements that are more in line with network resource interconnection service, which is meant to ensure resources can deliver power even during peak hours.

"The stakes are clear: If the United States is to maintain resource adequacy, economic competitiveness and technological leadership, the grid must be capable of interconnecting both load and supply at the pace required by today's economy," the coalition said.

NRG Energy urged an even bigger change: using open seasons to help large loads connect to the grid much more quickly.

"A more efficient, market-based approach employing open seasons would provide much needed certainty around the amount and location of large loads, which would benefit regional transmission system operators/independent system operators, transmission owners, generators and consumers alike by facilitating more orderly planning and capital investment," it told FERC.

Such processes have been used by natural gas pipelines to help raise capital and get customers, NRG said. The Alberta Electric System Operator recently used the concept to allocate open headroom on its system to data center customers.

"AESO began by establishing an interim, reliability-based megawatt limit (1,200 MW) on large load interconnections with its grid and then assigning that capacity to large loads ready to advance in the interconnection process in 'a fair, efficient and openly competitive manner' based, in part, on each large load's 'willingness to commit' through the posting of financial security," NRG said.

Open seasons will require a more proactive role from grid planners, but that should benefit the interconnection and transmission planning processes, NRG said.

"Such an approach is geared toward speed-to-market, getting the most megawatts online at the lowest overall cost, and ensuring a direct allocation of incremental costs to new large users of the grid," the company added.

What to do about reliability rules?

NERC intervened in the case to ask whether it should consider new rules to deal with issues caused by new large loads and whether the large load customers should have to follow them.

So far customers have not had to follow NERC's mandatory standards, but the FPA does say they can apply to "users" of the bulk power system and that could cover large customers.

"NERC plans to coordinate with stakeholders over the following year to explore potential revisions to the registry criteria and reliability standards that would incorporate large loads impacting the reliable operation of the BPS," the ERO told FERC.

The Large Loads Task Force is working on those issues now. NERC laid out a timeline that runs through 2028 to address any needed changes to its mandatory reliability standards in response to the proliferation of large customers.

"Depending on the outcome of these activities, next steps may include NERC registry criteria updates that help mitigate risk associated with emerging large loads," it said. "As discussed at the commission-led 2025 Reliability Technical Conference, any updates to registry criteria would be dependent upon whether relevant users, owners and operators of the BPS could materially impact, either individually or in aggregate, the reliability of the BPS." ■

Suggestions Offered for DOE's 'Speed to Power' Initiative

RTOs, Industry Groups, Advocates Lay out Priorities and Detail Problems

By John Cropley

The U.S. Department of Energy now has some feedback to consider as it pursues its Speed to Power initiative.

DOE *announced the program* Sept. 18 as a means to expedite development of the gigawatt-scale generation, transmission and grid infrastructure needed to support large-scale data centers and accelerate the artificial intelligence development those facilities would enable. (See *DOE Launches Speed to Power, Eyes Multi-GW Projects*.)

DOE launched the initiative by asking stakeholders for their input. The window for the *request for information* closed Nov. 21. Numerous entities submitted comments, and some shared them publicly.

The *American Public Power Association* said public power utilities face significant constraints as they try to expand their capacity for new loads while protecting their existing customers from risks and costs. So, APPA welcomed an expanded federal role in accelerating critical projects, and suggested some focus points for DOE, including:

- ensuring financial and technical assistance are available for public utilities and streamlining the application process;
- enabling joint action on projects that individual utilities could not undertake alone; and
- coordinating federal agencies' efforts.

APPA also said public-private joint ownership of transmission is an important tool with a track record of success. APPA flagged supply chain constraints, federal permitting delays and regulatory uncertainty as major barriers to success.

The *Software & Information Industry Association* raised a central concern: The U.S. lacks a cohesive national framework to ensure sufficient and reliable energy supply for data centers — permitting processes are often fragmented across local, state and federal jurisdictions, creating delays and uncertainty.

Why This Matters

The comments offer varied perspectives on the load growth widely expected to accompany AI data center development.

SIIA called for streamlining the permitting for AI infrastructure projects and for incentivizing nuclear energy to power AI; strengthening federal authority over transmission development and limiting discriminatory state-level practices; and reforming forecasting processes to include new large loads only when backed by significant upfront investments and financial commitments.

SIIA also suggested DOE use tools such as the Defense Production Act to accelerate American manufacturing of critical grid equipment.

RTO Recommendations

PJM offered five suggestions:

- The federal government could assume a key role in identifying which large load additions directly support national security and therefore should be prioritized.
- DOE could designate National Interest Electric Transmission Corridors, and if it did, it should use grid operators' regional and interregional planning processes.
- DOE should convene transmission planners nationwide to discuss greater standardization and uniformity for large load forecasting.
- DOE could request that FERC direct NERC to ensure to ensure a proper system of registration of large loads, and potentially to submit reliability standards.
- DOE should update its regulations to clarify the role of state and local authorities and grid operations in implementing any future orders under the Defense Production Act.

MISO's comments focused on how it is addressing the issue now, saying it has "updated and enhanced its processes across the transmission and resource planning horizons to efficiently support large load additions and improve the integration of large loads." And MISO also is working on several efforts to potentially enhance its existing processes.

One part of the RFI asks how DOE could assist with funding. MISO replied that it would like DOE to continue the $464.5 million Grid Resilience and Innovation Partnerships grant awarded under the Biden administration and threatened with revocation under the Trump administration. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States* and *SPP Moving Forward with JTIQ Transmission Projects*.)

MISO said also that supply chain frictions pose a significant threat to constructing the infrastructure needed to meet regional projected load growth. DOE could help the power industry by better understanding these frictions and helping address them.

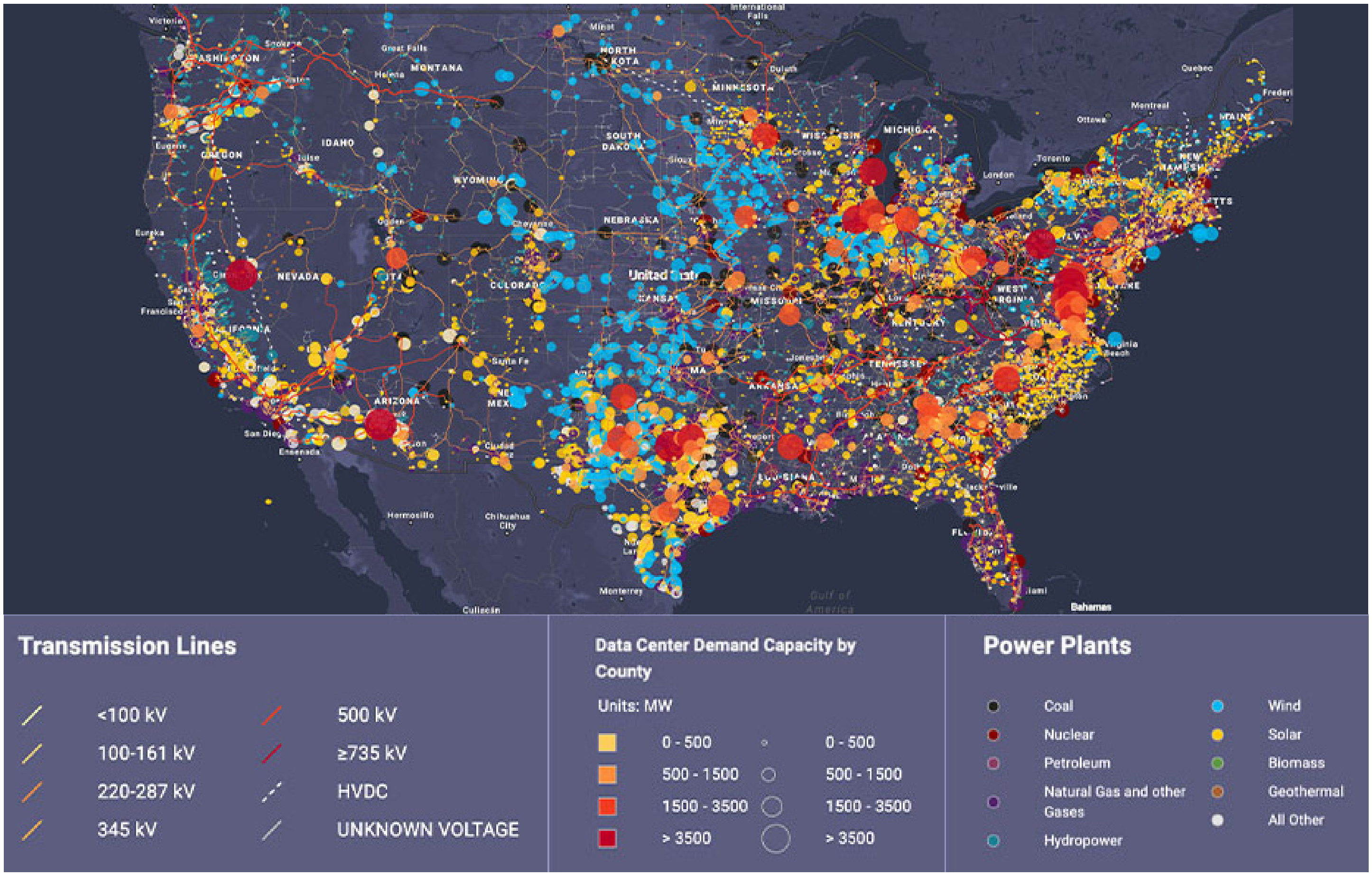
NRG Energy said DOE is best suited to a role in which it assists in creating a market for supply and flexible demand rather than directly subsidizing individual projects.

It said capital formation in the generation sector is lagging projected AI demand for three reasons: uncertainty of demand, high fixed costs throughout the supply chain and forward energy markets not signaling future demand sufficient to justify the level of investment needed to meet projections.

On this last point, NRG says: "The current situation of seeming underinvestment likely results from some combination of … overstated demand, few long-term buyers for supply relative to those seeking to sell long-term supply, and a tacit understanding that the market one would hope to do the lifting on capital formation is not the venue where this action necessarily takes place."

The *Electric Power Supply Association* emphasized the value of competitive wholesale electricity markets, accurate demand forecasting and regulatory and trade reforms.

Understanding the future demand



A National Renewable Energy Laboratory data viewer shows planned data centers and the generation and transmission assets that would serve them. | *NREL*

— how much, when and where — is foundational, EPSA said: "We should not rush headlong into potentially trillions of dollars of energy infrastructure investments without a calculated and realistic projection for what infrastructure is needed."

EPSA also said DOE should encourage voluntary partnerships between generators and large energy users to accelerate development while shielding ratepayers from financial risk; NEPA, the Clean Air Act and similar laws could be updated; and an independent bipartisan FERC would provide essential predictability for investors.

RA, Reliability, Gas Recommendations

Grid Action offered a series of suggestions:

- DOE should focus on facilitating transmission development that bridges interconnections and regions.
- DOE should expand the Transmission Facilitation Program for interregional transmission to address capital availability concerns.
- Congress should establish a siting and permitting framework for certain high-capacity interstate transmission lines similar to the Natural Gas Act for interstate pipelines; DOE should strengthen its Coordinated Interagency Transmission Authorizations and Permits Program; and the Trump administration should reduce environmental review bottlenecks.
- Congress and the administration should enact tax credits for high-capacity transmission; address supply chain constraints; cap wildfire liability; and maintain an agency workforce sufficient to support transmission siting and permitting.

The Institute for Policy Integrity at New York University School of Law said DOE should support NERC in development of a robust energy adequacy planning standard; initiate a nationwide study of interstate gas capacity; develop a rule to improve interregional transmission planning; assist development of a co-optimized transmission planning model; prioritize its funding decisions with a cost-benefit framework; and prioritize existing programs that incentivize grid expansion and innovation.

Americans for Prosperity urged consideration of generation, transmission and distribution occurring outside of the traditional grid, such as with microgrids, co-located generators and consumer-regulated electricity.

Secure The Grid Coalition offered a lengthy call for the DOE to protect the grid against geomagnetically induced currents, such as from solar storms or high-altitude nuclear warhead detonation.

DOE's National Renewable Energy Laboratory has created a data viewer in support of the Speed to Power initiative, with an *interactive U.S. map* showing some of the information developers need as they conduct site assessments, including: power demand from data centers that are planned, under construction or in operation; fiber-optic cable networks; transmission lines; power plants; substations; natural gas pipelines; day and night population; NERC reserve margins; FEMA risk indexes; and railroads. ■

Report Examines Interconnection Queue Rationing Efforts

Competitive Market Fairness Compromised, ACORE Analysis Concludes

By John Cropley

A new report examines CAISO, MISO, PJM and SPP efforts to accelerate interconnection queues and concludes that while some may succeed in speeding generation additions, some sacrifice fairness, transparency and open-access principles.

Early evidence also suggests that these emergency mechanisms produce portfolios heavily weighted toward thermal resources that potentially face high network upgrade costs, according to the analysis performed by Grid Strategies for the American Council on Renewable Energy.

The ACORE report warns that these programs are labeled as one-time measures but could be extended or repeated.

Instead of that, the authors urge a long-term strategy that upholds open access and competition, and they propose two paths to this goal:

- An Enhanced Readiness Fast Lane — a narrowly tailored, transparent pathway for projects that address verified near-term reliability needs, activated only under specific conditions and governed by transparent, objective and nondiscriminatory criteria.
- Proactive Integration with Transmission Planning — a restructured baseline queue that aligns project intake with available and planned transmission capacity, using scoring systems to prioritize commercially ready and policy-aligned resources.

ACORE released "*Interconnection Queue Rationing Reforms*" on Nov. 25. The authors acknowledge that while priority interconnection processing can be designed to uphold the open-access principles that are the cornerstone of competitive wholesale energy markets, many such efforts are failing to meet this ideal.

"Discriminatory queue processing undermines fair competition among technologies and interconnection customers," they write, "introducing regulatory uncertainty that ultimately harms consumers."

The report drills down on four efforts:

- CAISO's Interconnection Process Enhancements;
- MISO's Expedited Resource Addition Study;
- PJM's Reliability Resource Initiative; and
- SPP's Expedited Resource Adequacy Study.

All were implemented after FERC Order 2023 directed a shift from the first-come, first-served approach to queue management to first-ready, first-served.

The driving factors for the changes are well known: The U.S. interconnection queue has grown to more than 2.3 TW of potential capacity, interconnection timelines have grown to more than five years on average and fewer than 20% of queued projects reach commercial operation. Meanwhile, power demand is expected to grow significantly, costs are increasing and the supply chain to build all this capacity is bottlenecked in places.

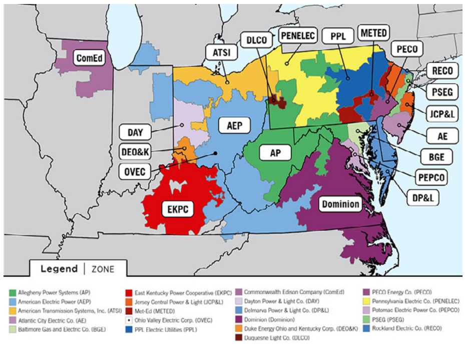
The authors say Order 2023 produced only modest changes, but early evidence suggests grid operators' additional reforms beyond the order have begun to streamline and speed queue processing, and show great promise.

The authors take a critical view of the emergency rationing mechanisms also being implemented and say the RTOs and ISOs should give their reforms enough time to work before resorting to emergency measures.

"Queue rationing mechanisms like these should not become the default operating model or a substitute for comprehensive reforms," the report states. "As a guiding principle, grid operators should exhaust all other alternatives that make the standard interconnection queue more effective before invoking new emergency rationings."

Why This Matters

Efforts to expedite capacity additions that include "queue jumping" have proved controversial.



A new report examines interconnection queue rationing reforms by PJM and three other major grid operators. | *PJM*

Rationing measures are also drawing legal challenges, with environmental groups recently filing suits against the MISO and SPP processes in the D.C. Circuit Court of Appeals, arguing the programs are unjustly preferential by allowing primarily fossil fuel generation to jump queues while ratepayers are billed for the upgrades needed to accommodate it. (See *Enviros Challenge MISO, SPP Queue Express Lanes*.)

The authors draw a distinction between the temporary fast-track programs MISO, PJM and SPP adopted and the permanent restructuring CAISO undertook.

CAISO's changes were not without controversy, they write, but "on balance, CAISO's IPE represents one of the most comprehensive queue reforms among system operators to date."

Nonetheless, timelines remain extended, the percentage of projects advancing remains low and transmission constraints continue to strand low-cost energy potential.

"The upcoming refinements under IPE 5.0, particularly around energy-only conversion, long lead-time upgrades and equitable scoring oversight, will determine whether CAISO can transform this framework into a sustainable, scalable model for integrating the volumes of clean energy required to meet California's 2030 and 2045 goals," the authors write. ■

Panelists: U.S., Canada Bound by Interties, Mutual Interests Despite Tariff Rift

Integrated Grid 'Purest' Example of Countries' Energy Partnership, NERC Exec Says

By Robert Mullin

SEATTLE — The longstanding links among U.S. and Canadian electricity grid operators won't be fractured easily by the tariff-driven political rift between Washington, D.C., and Ottawa, industry participants on both sides of the border say.

"The grid really recognizes no political boundaries," NERC Vice President of Government Affairs Fritz Hirst said Nov. 10 at the Annual Meeting of the National Association of Regulatory Utility Commissioners in Seattle. He was speaking during a "Northern Exposure" panel discussion moderated by Nevada Public Utilities Commissioner Tammy Cordova.

"Like any other region anywhere on the grid, we have a natural complementarity north and south of the border where different regions depend on each other for energy transfers when needed," Hirst said. "It's probably one of the purest examples of the energy partnership we have between Canada and the U.S."

Hirst noted that while Canada accounts for 10% of North American electricity load, it represents "a critical piece of the pie," with 30 U.S. states trading power with their northern neighbor to the tune of 70 million TWh per year — enough to power about 6 million homes.

Maine Public Utilities Commission Chair Philip Bartlett pointed to a concrete example of that cross-border relationship: Residents in the northern part of his state receive all their power from either local resources or transmission coming out of neighboring Canadian province New Brunswick.

"For us, this is particularly important, and when we started hearing news of tariffs and concerns about the relationship between the United States and Canada, we got pretty nervous, because these customers are really wholly dependent on the very positive relationship that we've built over the years," Bartlett said.

Bartlett pointed to the lines connecting New Brunswick with the larger ISO-NE system and noted that the New England Clean Energy Connect (NECEC), a 320-kV HVDC line capable of delivering 1,200 MW of Québec hydropower output to Massachusetts, is *expected to be completed* by the end of 2025.

New England's relationship with Canada is expected to grow in importance, Bartlett said, in part because of the region's lack of natural gas pipeline capacity to support new gas-fired plants and the Trump administration's halting of offshore wind projects. (See *Feds Pile on More Barriers to Wind and Solar*.)

From left: Tammy Cordova, Public Utilities Commission of Nevada; Philip Bartlett, Maine Public Utilities Commission; Francois Emond, Régie de l'énergie; Fritz Hirst, NERC; Amy Sopinka, Powerex. | © *RTO Insider*

Notable Quote

"The grid really recognizes no political boundaries."

—NERC Vice President of Government Affairs Fritz Hirst

"Maine and the region had been really expecting to rely on offshore wind as a really important way for us to meet increased load, and also to deal with the expected retirement of some of our older oil plants," he said. "So given that offshore wind is delayed in the United States, to the extent there are opportunities in Canada to move faster, that is something that could be a real reliability benefit to the region."

Canada's Internal Strains

"Yes, it's hard to be a neighbor to the U.S. right now," said Francois Emond, a commissioner with Régie de l'énergie du Quebec (part of the Canada Energy Regulator), referring to the tariffs Trump imposed on Canada earlier in 2025.

In laying out the top three challenges he thinks Canada faces now, Emond pointed first to the impact of the trade dispute with its southern neighbor.

"Canada's economic health is highly susceptible to global political and trade shifts, a vulnerability that's rooted in its heavy reliance on the U.S. market, with two-way trade accounting for about 65% of the GDP," Emond said.

Tariffs and other global disruptions — such as supply chain issues — drive up costs for consumer goods and construction materials, including those needed for transmission lines and other energy infrastructure, he said.

The second challenge is the "regional and political divisions" that threaten national unity, with parties in Alberta — and Québec — reviving talk about separating from Canada.

"Tensions persist between regions like Alberta and Ottawa, and Quebec and Ottawa, fueled by disagreements over resource allocation, federal fiscal policy and differing approaches to the energy development and climate actions," Emond said.

The third challenge has to do with the intersection of climate policy and energy affordability. Emond said that while Canada is committed by law to getting to net zero carbon emissions by 2050, the nation's carbon tax "has become a lightning rod for political contention, with some provincial leaders calling for its removal, citing its impact on the cost of living and business competitiveness."

"The priority for the country right now is to build resilience across its trade networks, critical infrastructure and the national unity to prevent increasing domestic and global volatility," he said.

But even in light of that priority, Emond acknowledged the reality that, from an electricity standpoint, Canada's provinces are more interconnected to their U.S. neighbors than to each other, a state of affairs he attributes to the country's internal politics and lack of a national energy policy.

"If any provinces in Canada are saying we're going to cut power to the U.S. because we don't like what they're doing, it's not possible … the grid is integrated, you cannot do that, and we need also the power coming from the U.S.," he said.

'Giant Battery for the West'

Amy Sopinka, director of market policy for Powerex, the power marketing arm of Vancouver-based BC Hydro, said the British Columbia grid is connected to the neighboring province of Alberta and to the Bonneville Power Administration system in Washington, but that 90% of its power trading is with U.S. entities.

Sopinka pointed to the B.C. grid's contribution to the broad geographical diversity of load and resources in the Western Interconnection: It's a winter-peaking system compared with the summer-peaking systems in the U.S. Southwest, so its periods of highest demand complement much of the rest of the Western Interconnection. Also, BC Hydro controls about 19 GW of generating resources, including 16 GW of hydroelectric capacity, much of which are storage dams that "can act like a giant battery for the West," Sopinka said.

"We've been both net importers and net exporters over the years," she said.

Sopinka noted Powerex's commitment to participating in Western Power Pool's Western Resource Adequacy Program (WRAP) and SPP's Markets+, the latter of which is to launch in 2027.

"The Western Resource Adequacy Program is a tool for formalizing the relationship of that resource diversity and demand diversity" for ensuring and accrediting RA, while Markets+ "will allow for the transactions" that support that diversity, Sopinka said.

'Continental Interconnection'

Cordova asked panelists to share their hopes for the future of the U.S.-Canada electricity relationship.

Bartlett said he hopes for "more integrated analysis" of certain benefits and needs on both sides of the border, as well as "additional partnerships" and the identification of new transmission lines that serve both countries.

"I think the magic wand is we need the [U.S.] federal government to be more encouraging in this effort, because I think it really would benefit the United States in terms of the economic development, [and] the ability for us to build out the renewable resources and other resources that we need, but also do it in a way that is much more reliable and probably a much lower cost, if we can have effective interconnections," Bartlett said.

But Bartlett also expressed concern that if the U.S. "were to go through two or three administrations like this one, that's going to make it very difficult for Canadian governments."

Emond said those in the electric sector might have to look beyond the current challenges to adopt "a more pragmatic way of thinking" that moves beyond politics to identify real needs and "keep discussing," "making deals" and "do what's needed for the consumers."

"We need more generation in North America; that evidence is quite clear as we confront our economic needs [and] the AI race," Hirst said. "So, I think I would just underscore the need to continue uplifting the North American relationship and truly think of us as a continental interconnection."

"We have advantages, and it's best if we can share them all, and then the system becomes more reliable," Sopinka said. ■

EIA: 2024 Hurricanes Led to Highest U.S. Outage Durations in a Decade

By James Downing

U.S. electricity outage hours reached their highest levels in a decade in 2024 due to the impact of Hurricanes Beryl, Helene and Milton, the EIA *reported*.

From 2014 to 2024, electricity customers averaged around two hours of outages a year unrelated to major events such as hurricanes or storms, interference from vegetation near power lines or "atypical" utility operations, EIA said.

Interruptions attributed to major weather events averaged four hours, the agency said.

In 2024, the major hurricanes added another seven hours to that figure — meaning the average customer experienced 11 hours of outages.

Outages are categorized by two metrics in the industry: The system average interruption duration index (SAIDI) measures the total duration of non-momentary outages, and the system average interruption frequency index (SAIFI) measures the number of outages in the year.

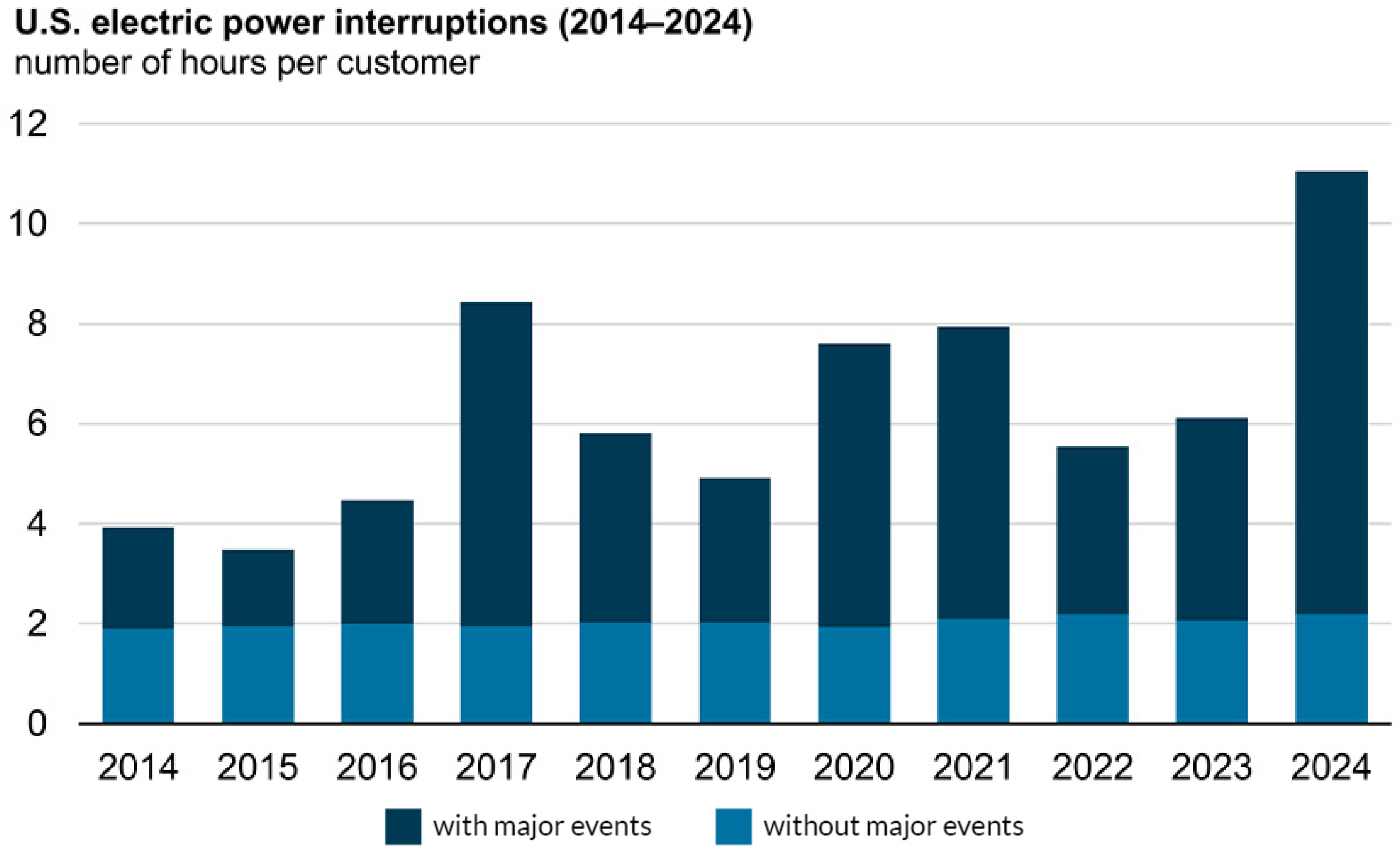
Nationally, customers averaged 1.5 outages last year. Hawaii led the country on the SAIFI, being the only state to see its power customers average more than four outages in 2024 — but the overall time they were without power was well below the national average. Hawaii had a high number of outages due to bad weather, volcanic activity, unexpected outages at oil companies and issues connecting new power plants.

Maine and Vermont took second and third place, though Mainers averaged nearly 30 hours in SAIDI and Vermonters just under 15 hours. Utilities in both states often have to deal with treefalls knocking out power, EIA said.

Maine customers averaged longer outages than customers in Florida, North Carolina and Texas, despite not being hit by any of the major hurricanes that drove the spike in SAIDI in those three states and nationally. Those Southern states saw customers average between 25 and 30 hours of SAIDI, about half the duration of South Carolina customers who averaged 53 hours of outages.

Hurricane Beryl knocked out power to 2.6 million customers in Texas in July 2024 while September's Hurricane Helene left 5.9 million customers across 10 states without power, with 1.2 million of those in South Carolina. In October, Hurricane Milton knocked out power to 3.4 million customers in Florida.

Arizona, South Dakota, North Dakota and Massachusetts experienced less than two hours of outages in 2024, while South Dakota, Maryland, Illinois and Massachusetts all averaged less than one outage that year. ■



EIA's graph showing the last decade of average outages by utility customer, split by major events such as hurricanes. | *EIA*

Pathways' ROWE Could Offer RA Program, PGE Says

By Henrik Nilsson

The West-Wide Governance Pathways Initiative could lead the charge on developing an alternative to the Western Resource Adequacy Program that would integrate with CAISO's Extended Day-Ahead Market, according to Pam Sporborg, Pathways co-chair and director of transmission and markets at Portland General Electric.

PGE continues to engage with the Western Power Pool on WRAP's development. But if the program cannot be aligned with both SPP's Markets+ and EDAM, Pathways' Regional Organization for Western Energy (ROWE) could step in as an alternative, Sporborg said in a Nov. 13 interview with *RTO Insider*.

ROWE was created to assume governance of CAISO's Western Energy Imbalance Market and the soon-to-be-launched EDAM. Some stakeholders have expressed an interest in building the program to also offer additional voluntary market services. (See *Pathways Initiative Exploring Funding Options, Issues RFP to Staff ROWE*.)

An RA program could be one of those offerings if EDAM participants' concerns about WRAP are not resolved, according to Sporborg.

"An alternative would be to have an RA program that was governed solely by the Pathways' new regional organization that would be more integrated into the EDAM," Sporborg said. She noted the alternative must "provide enhanced value for PGE and PGE's customers and other Western utility customers."

Her comments came after the Oct. 31 deadline for entities to commit to WRAP's first financially "binding" season covering winter 2027/28. The final WRAP commitments showed the program has mostly been divided along the line of participants in CAISO's EDAM and SPP's Markets+.

Among the five utilities withdrawing from the WRAP, four — NV Energy, PacifiCorp, PGE and Public Service Company of New Mexico — have committed to joining the EDAM, while Eugene Water & Electric Board will be participating in Markets+ by virtue of its location within the Bonneville Power Administration's balancing authority area.

Of the 16 committed to the first binding season, 11 are slated to join Markets+, two are leaning to EDAM and three are uncommitted to either day-ahead market. (See *WRAP Wins Commitments from 16 Entities*.)

| © RTO Insider

Notable Quote

"Before we can commit to a financially binding program that has financial penalties for withdrawal; financial penalties for noncompliance; and the risks that that would put our customers on, we want to actually see how those design evolutions materialize."

— Pam Sporborg, Pathways co-chair and director of transmission and markets at Portland General Electric

The divide and the fact that WRAP is a program requirement for Markets+ has raised concerns about the program's governance structure, Sporborg said.

Markets+ will gain a larger share of the voting power, "and we need to see and understand how that governance will evolve to ensure that we can be confident that the program will remain equitable for EDAM entities," she said.

Another issue is that WRAP was conceived before day-ahead markets in the West, and the program was intended to work within a different footprint from the one emerging under Markets+ and EDAM, according to Sporborg.

WRAP is realigning its operations program to reflect the day-ahead market reality. This will "fundamentally change" what the planning reserve margin is and what the diversity savings are, Sporborg said.

"We don't have enough information right now to make a financially binding decision based on that realignment," she said.

PGE listed its concerns in an Oct. 29 letter to the Oregon Public Utility Commission. The utility pointed to efforts by the WRAP's Planning Reserve Margin Task Force to evaluate new methodologies for setting planning reserve margins for program participants, as well as concerns about the technology underlying the program.

"Before we can commit to a financially binding program that has financial penalties for withdrawal; financial penalties for noncompliance; and the risks that that would put our customers on, we want to actually see how those design evolutions materialize," Sporborg said.

Talk of an alternative RA program has been ongoing since at least Oct. 21, after NV Energy said during a hearing before the Public Utilities Commission of Nevada that it is discussing the option with other EDAM participants.

Since then, a group of nine EDAM entities have commissioned the Brattle Group to study the impact on planning reserve margins of an RA program encompassing expected EDAM participants. (See *Brattle Study Finds Similar PRMs Under Alternative Western RA Footprint*.)

PGE was among those ordering the study.

"It's a consistent and expected result that the bigger your footprint, the more connected your footprint, the more savings that you can achieve through that diversity," Sporborg said.

But the study also suggested that there are savings to be made in a separate EDAM-aligned RA program, according to Sporborg.

"So, that gives us the confidence that we can continue to work with the [Western] Power Pool on the market alignment but also help us understand that if we can't find a solution that is equitable to the EDAM, we could pursue this alternative and not be worse off than we would from that geographic WRAP perspective," she added.

Pathways' potential RA role was suggested by Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition, during an Oregon PUC meeting Nov. 25 about the state's RA program and WRAP. (See related story *Oregon PUC Votes to Waive RA Penalties for Independent Suppliers*.)

Gray noted Pathways could eventually offer several "new solutions and services in the West."

"There's a good regional solution here that takes advantage of both load and resource diversity in multiple time zones and multiple latitudes," Gray said about Pathways. "And that was the value proposition of WRAP. That's the value proposition of both Markets+ and EDAM."

When asked how WPP is working to address EDAM entities' concerns about WRAP, organization Chief Strategy Officer Rebecca Sexton said, "With the commitments for 2027/2028, we are focused on binding operations and have a lot to do to get ready for that.

"The results of that work should improve the program and benefit our committed participants, as well as any participant who chooses to return," Sexton told *RTO Insider* in an email. ■

El Paso Electric Finds Solar Procurement Solution After Tariff Hikes

EPE Brings Renewable Plan Back to N.M. Regulators for Approval

By Elaine Goodman

El Paso Electric's past power purchases include 20 MW from the Roadrunner solar facility in Santa Teresa, N.M.. | *El Paso Electric*

El Paso Electric is again seeking regulatory approval for its New Mexico renewable energy plan after resolving tariff-related cost uncertainty of a solar-plus-storage procurement proposed in the plan.

The New Mexico Public Regulation Commission rejected the plan in October based on concerns about the cost of energy from the proposed 150-MW Santa Teresa solar project. EPE reported in August that developer DE Shaw Renewable Investments (DESRI) had told it the project had been "materially and adversely impacted by recent changes in law, in particular related to the imposition of tariffs by President Trump."

The tariffs were expected to "result in millions of dollars worth of unplanned cost increases for construction of the generating facility," the developer said. In an Oct. 16 order, the PRC said it could not approve EPE's plan because the cost of the Dona Ana County-based project was unknown.

But since then, EPE has worked out a deal with DESRI calling for the utility to pay the same rate for energy from the project as in their previous agreement but with the contract terms extended to 25 years rather than 20.

The plan the commission is being asked to approve covers the first 20 years of the agreement; EPE would bear the risk of the five-year extension, PRC staff said in a filing.

Why This Matters

El Paso Electric's struggles with renewable energy procurement come as New Mexico's renewable portfolio standard jumped to 40% in 2025, after being at 20% since 2020.

The expected cost of the project's energy assigned to New Mexico for 2026 is \$45.67/MWh. That is below an inflation-adjusted renewable cost threshold of \$74.14/MWh.

The PRC on Nov. 25 granted EPE's motion for a rehearing, which could take place as soon as Dec. 11.

EPE and DESRI had not responded to *RTO Insider*'s request for more details on the tariff impacts at press time.

RPS Challenges

New Mexico's investor-owned utilities file a plan each year on how they will meet the state's renewable portfolio standard in the following year.

The required percentage of zero-carbon resources supplied for retail electricity sales increased to 40% in 2025, after sitting at 20% since 2020. It will continue to rise through 2045, when it reaches 100%.

In 2023, EPE supplied about 16% of retail energy sales to New Mexico customers with renewable resources, a figure that grew to just over 20% in 2024.

EPE's 2026 plan includes renewables and renewable energy certificates from an approved portfolio as well as the proposed Santa Teresa procurement.

Santa Teresa will be built at the former site of the Hecate solar project, which at one time was expected to be in service by 2022 but was never built. DESRI took ownership of the project. EPE's power purchase agreement for Hecate was terminated in 2024, and the utility received \$14.9 million in liquidated damages, according to the 2026 plan.

EPE, which serves customers in New Mexico and Texas, noted in its plan the challenges of providing electricity in jurisdictions with different renewable energy requirements. The utility has previously received PRC permission to adjust the amount of renewable energy allocated to New Mexico, rather than Texas, to meet New Mexico's RPS targets.

For the Santa Teresa project, EPE has asked to purchase all the solar energy generated in 2026 and allocate it to New Mexico, starting when the project comes online midyear. That allocation would be needed to meet the 40% RPS target in 2026, but it would likely be a short-term arrangement.

"EPE would not expect to propose allocation of the total annual energy output of the [Santa Teresa project] in 2027," the company says in its proposed plan.

Of the project's 150 MW of battery storage, EPE wants to purchase and include 50 MW in its RPS portfolio. ■

Oregon PUC Votes to Waive RA Penalties for Independent Suppliers

Vote Prompted by WRAP Developments

By Henrik Nilsson

Citing developments within the Western Power Pool's Western Resource Adequacy Program, the Oregon Public Utilities Commission waived penalties for electric service suppliers participating in the state's alternative RA program.

The three-member commission voted Nov. 25 in favor of staff's recommendation to grant a waiver for electric service suppliers (ESSs) that make filings in Oregon's state resource adequacy program and directed staff to work with the PUC's Administrative Hearing Division to decide whether to open a rulemaking or investigation to consider amendments to RA rules.

ESSs are the product of Oregon's electricity restructuring law, which gave non-residential customers the option to purchase energy from independent PUC-certified suppliers rather than their utilities through the state's direct access program.

The PUC's vote came after the Northwest & Intermountain Power Producers Coalition filed a motion asking the commission to consider the waiver because of developments within WRAP, which impacted Oregon's separate RA program.

Entities not part of WRAP must participate in the state's RA program, which is mostly modeled on WRAP, except it does not have specified penalties. Those are instead determined by the commission, *according to a staff memo*.

The commission previously waived penalties for the 2025-2027 compliance period after WRAP delayed its first binding period. Until the recent vote, no waiver existed for the 2027-2029 cycle, but the commission approved one in response to recent WRAP developments.

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Why This Matters

The vote signals the impact recent commitments and exits from WRAP have on the West, and the difficulties of building an RA program.

WRAP participants had until Oct. 31 to commit to the program's binding season beginning in winter 2027/2028. Citing concern about the program's readiness, Oregon-based utilities PacifiCorp and Portland General Electric exited, along with Calpine Energy Solutions, which operates as an ESS in the state. (See *WRAP Wins Commitments from 16 Entities*.)

The entities could choose to rejoin WRAP, but if they do not, they must demonstrate compliance with Oregon's RA requirements unless another regional RA program becomes available.

In light of these developments, NIPPC asked the Oregon PUC to provide clarity by adopting a penalty framework for the state RA program and adopting an alternative compliance pathway for ESSs.

NIPPC said ESSs are struggling to meet both WRAP and state RA requirements, in particular because of difficulties procuring transmission rights from third-party transmission providers and rights holders.

"[NIPPC] said that uncertainty about ESSs' ability to comply with requirements or reasonably limit penalties for non-compliance in either WRAP or the state program could irreparably harm the direct access (DA) market by leaving DA customers with 'no reasonable choice' but to provide notice to their incumbent utilities of their intent to return to cost-of-service rates," according to the memo. "Although WRAP and state program penalties are not scheduled to apply until 2027, NIPPC stressed the urgency of its first request, that the commission clarify state program penalties, noting that DA customers must typically provide at least two years' notice to return to their incumbent utilities."

In response to NIPPC's motion, PUC staff said it "believes there is good cause for the commission to waive [RA penalties] for ESSs for the next state program compliance process. This waiver would remove the requirement for the commission to make a compliance determination on ESSs' forward showings and the firm requirements related to remedies and penalties."

Staff added that the waiver should give it enough time to investigate and consider changes to the state RA program.

Staff also provided a five-point checklist for what it believes the commission should accomplish moving forward:

- Provide load-serving entities with near-term clarity about state RA requirements and consequences of noncompliance.
- Ensure, to the extent possible, non-preferential treatment between ESSs and utilities and fair treatment between participants in the state RA program and those in WRAP.
- Minimize disparities between available RA programs while also incentivizing participation in a regional RA program.
- Ensure the commission maintains visibility into the RA positions of LSEs and the potential for impacts on all retail customers.
- Ensure compliance with state program requirements is feasible and incentivized by the program's design.

'Ensuring Reliability and Competition'

Stakeholders participating in the meeting backed staff's recommendations.

Marie Barlow, an attorney with NewSun Energy, said the organization supports the efforts.

"We just want to emphasize that the goal for the resource adequacy and the direct access programs should remain focused on ensuring reliability and competition," Barlow said. "The outcome that we absolutely do not want is for the direct access program to collapse under the weight of those resource adequacy obligations, resulting in those loads returning to the utilities and further burdening those utilities with their greenhouse gas reductions obligations and additional reliability obligations, especially at a time when they're already going to be burdened with rapidly increasing loads."

Other organizations and companies also voiced their support, including PGE, PacifiCorp and Calpine.

PUC Chair Letha Tawney noted that the vote does not mean there will be no RA obligations for ESSs and that most parties appear to agree they should continue to present forward showings.

"I think there may be interim data requests that staff will have to request and ESSs might need to be responsive to," Tawney said. "As we go forward through this time frame, it might be that every … 24 months showing is sort of sufficient given how dynamic the space is. But I'm hearing an openness to that dialog, and I appreciate that." ■

'Frustrated' CDWR Requests CAISO Reconsider Tx Access Charge Proposal

NV Energy Asks for More Thorough Policy Meetings

By David Krause

The California Department of Water Resources and other parties have asked CAISO to restart a transmission access charge initiative that was put on hold in 2018 due to the development of the ISO's Extended Day-Ahead Market.

CDWR, along with the Bay Area Municipal Transmission Group and the State Water Contractors, want CAISO to bring back a drafted final *proposal* regarding the ISO's Transmission Access Charge (TAC) rules in order to possibly reduce the amount of new transmission needed in the state.

CAISO's current TAC rules measure transmission use with a "volumetric-only" approach, which "fails to reflect cost causation and utilization of the transmission system, resulting in inequitable allocation of costs," the CDWR group said in Nov. 13 *comments* to CAISO's draft 2026-2028 policy initiatives road map.

"Costs should reflect that transmission networks are built to handle peak demand when the grid is strained the most," the group said.

CAISO should instead recover a larger portion of fixed electric transmission costs through a demand-based rate structure, and less from volumetric rates, the group said. Doing so would incentivize better load management practices and reduce the need for new transmission that is driven by peak demand requirements, they said.

Current TAC rules send inefficient price signals to behind-the-meter battery storage resources operators, the group said. If price signals were accounted for more specifically, CAISO might find it needs to plan for less new transmission infrastructure, the group said.

In February, CDWR proposed to restart the TAC initiative and bring back the 2018 proposal. However, CAISO dismissed CDWR's request because the "levels of behind-the-meter solar have stabilized, rendering these changes unnecessary and overly complex in today's market," CAISO said, according to the CDWR group's Nov. 13 comments.

CDWR is concerned about CAISO's "misunderstanding of the substance and need" for the TAC proposal and are "frustrated by the process used to date," they said.

"CAISO infrastructure staff have dismissed the need for this initiative, without any stakeholder meetings to discuss the issues that motivated the initiative in 2016-2018, or to consider input from stakeholders on the current need for the TAC structure changes that were fully vetted and proposed to be adopted in 2018," the group said.

The 2018 TAC initiative was supported by CAISO's Department of Market Monitoring, California's three largest investor-owned utilities, municipal utilities, independent transmission developers, retail marketers and the California Public Utilities Commission, the group said. The proposal supports CAISO's resource adequacy capacity program for required contributions to coincident peak demand and DMM's support for allocation of natural gas transmission infrastructure costs, they said.

The current TAC rules started in 2001, and the structure has remained "relatively stable" through the intervening years, CAISO staff said in the 2018 draft final proposal.

Why This Matters

With CAISO to release its 2026-2028 policy road map next month, the California Department of Water Resources is leading a push to have the ISO revive a plan to revise certain Transmission Access Charge rules as part of the upcoming policy update cycle.

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CDWR's comments were filed in CAISO's annual policy initiatives road map process, which determines the policy initiatives for the following three years. CAISO plans to release a final policy road map in December for the 2026-2028 cycle.

NV Energy Requests Policy Review Changes

NV Energy filed comments about CAISO's policy road map, asking CAISO to evaluate the frequency, length and content that is reviewed in stakeholder policy meeting sessions.

The ISO's policy meeting sessions have become longer but have been held less frequently. This approach to policy development with stakeholders has caused certain meeting materials to be condensed or skipped altogether, NV Energy representative Lindsey Schlekeway said in Nov. 13 *comments* to CAISO. The long gaps between meeting sessions have made it difficult to track and follow issues raised by stakeholders, Schlekeway said.

"It would be helpful for CAISO to be mindful of the resource constraints considering the activities that are underway in the West," Schlekeway said. "The stakeholder process may have large impacts to the market design, and NV Energy would like to dedicate sufficient time to each initiative in order to provide the most informed and helpful comments to CAISO."

NV Energy recommended CAISO hold three-day meeting sessions, rather than one meeting per month, to review complex issues with stakeholders. ■

Higher Prices Stressing Ontario Mines, Greenhouse Growers

Market Renewal Program Clears 6-Month Mark

By Rich Heidorn Jr.

Higher prices under Ontario's renewed market are causing heartburn for mines and greenhouse growers, stakeholders told IESO on Nov. 26.

During the ISO's quarterly market briefing, IESO officials said the market is performing well, with "intuitive price formation," and that no new "high-priority defects" have been discovered since their last briefing in August. (See *Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months*.)

"We've now got about six months of operating in the renewed market behind us and … I think everybody's learning and building their understanding of the new market dynamics that we're seeing as we shift through each season," said Candice Trickey, IESO's director of market readiness and customer experience. "Overall, [based on] everything I hear from you and that I see internally, we are all making, collectively, really good progress in working in this new system."

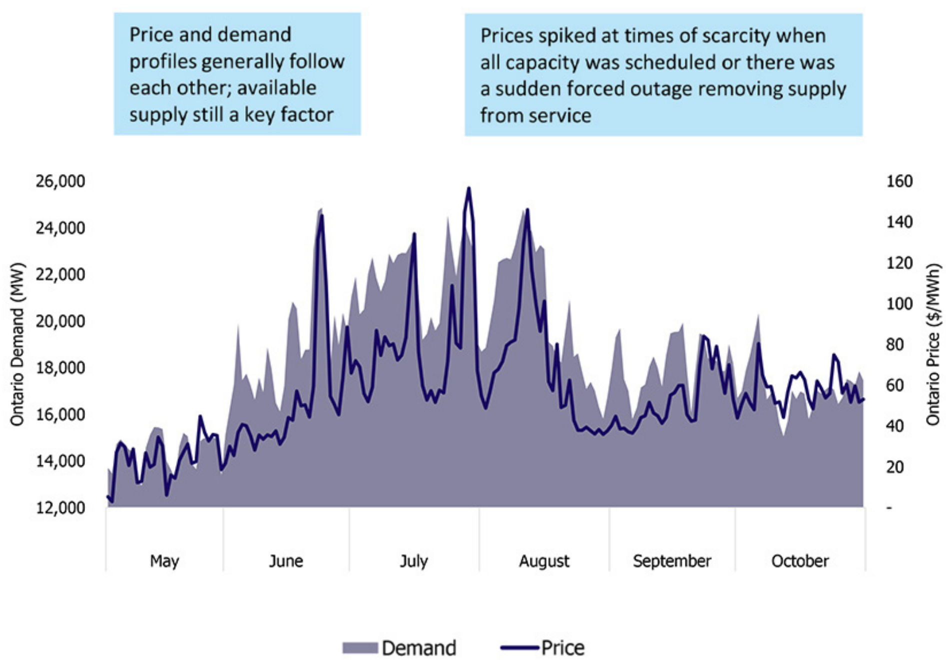
However, several stakeholders said they are facing challenges from higher prices since the new market launched May 1.

Alain Cote of Vale Canada — whose five mines and other operations use about 200 MW per hour — said Ontario Zonal Prices in November have risen from about $50/MWh to about $80/MWh in November.

"I'm just having a hard time … forecasting that," he said. "It's a big swing."

Consultant Stephanie Freund, who advises commercial greenhouse companies in southwest Ontario, said her clients have seen increasing price spikes since October, when they turn on their grow lights to nurture winter crops.

"They are really struggling … trying to keep up with the day-ahead [market] in order to manage their lighting schedules … to avoid the spikes," Freund said. "They've never seen such high electricity prices as now. … They won't be able to afford running" the lights. She asked if IESO had tools to help them manage the volatility.



Prices rose with demand, except where available supply was scarce, or there was a sudden forced outage. | *IESO*

Why This Matters

Ontario's nodal market, which created a financially binding day-ahead market and about 1,000 pricing nodes, is intended to increase market efficiency, transparency and competition.

Darren Matsugu, IESO's director of markets, said Ontario is seeing higher prices because it is the peak of the fall maintenance outage season. "We are definitely in the period where we have the most resources on outage to make sure that we have that availability before the winter," he said. He suggested Freund talk to the ISO's customer relations team about ways to manage the high prices.

Cal Brooks, of FirstLight Power, said that — even accounting for inputs like gas prices and system load — prices appear to be higher than under the Hourly Ontario Energy Price (HOEP), which the ISO used before the Market Renewal Program introduced nodal pricing and a financially binding day-ahead market.

"Do you see that as … something good in that maybe real supply and demand signals are now being reflected in a way they weren't under the old market?" Brooks asked.

Matsugu noted that the HOEP uniform clearing prices did not include congestion and losses, which are now reflected in LMPs.

"The structural changes that we put in place are to better align the price signals we're sending with the underlying system conditions," he said. "Those system conditions are continuing to change. We are getting into tighter and tighter conditions than we have before, and so certainly we would expect that … the underlying prices [would] be higher."

The ISO says the new market will produce net cost savings for consumers by reducing out-of-market payments and improving the efficiency of scheduling resources.

"I think we are seeing the benefits, particularly when we talk about our intraday unit commitment and our day-ahead commitment," Matsugu said.

IESO officials said market prices have reflected system conditions, with real-time and day-ahead prices converging when actual conditions match forecasts and varying with deviations in real time.

Jennifer Jayapalan, of Workbench Energy, said her company has seen big changes in how some resources are being used. "We've seen a lot more demand response activations, not just in peak conditions, but also into the fall and as recently as the last week or two," she said. "And we're seeing a lot more operating reserve [OR] activations across this period as compared to really all years prior to MRP. And neither of these two actions are really publicly reported anywhere by IESO, and both are quite expensive."

Matsugu said scheduled generation outages contributed to the DR and OR activations and that the ISO will consider whether it can provide more transparency on such actions. "We don't have, necessarily, all the same resources available that we had during our peak of the summer, but we do that outage planning to correlate with the expected levels of demand."

Defect Caused Demand Fluctuations

Trickey said the ISO investigated whether a defect that was causing demand fluctuations had an impact on hourly DR activations and concluded that it did not create any inappropriate activations.

The defect caused the Ontario demand values published in IESO's *Realtime Totals Report* to change by hundreds of megawatts for only a few five-minute intervals.

Because of the unpredictable nature of variables such as supply disruptions, sudden increases in heating or cooling demand, and neighboring system conditions, there are often changes in demand from one interval to the next. But "swings of several hundred megawatts for only a few intervals have historically been quite rare," the ISO said in a *presentation*.

IESO said it identified a calculation that overstated demand when hourly DR resources are on standby. The ISO has implemented a manual workaround to counter the defect pending a permanent fix.

Without the workaround, the defect could result in incorrect prices for impacted intervals and incorrect peak demand hours for the Industrial Conservation Initiative if they occur on a potential peak day. ICI participants pay their share of Global Adjustment charges based on their peak demand factor, which is calculated based on their contribution to the top five peak hours over a year.

IESO identified 38 intervals with incorrect prices and corrected them with administrative prices. It confirmed that the top 10 peaks posted on the *Peak Tracker* webpage were not affected.

Settlements, Defects

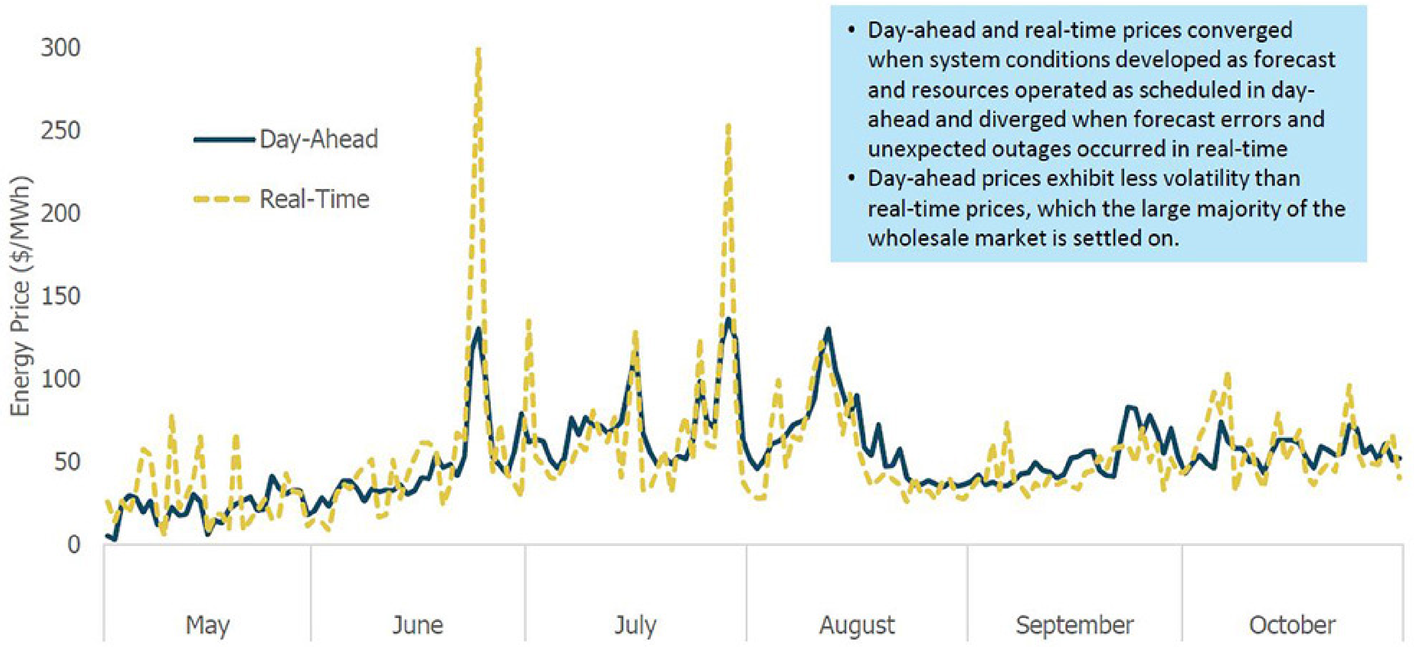
IESO officials said they have improved settlement processing times, and that statements and invoices issued in October and November were delivered ahead of the ISO's 5 p.m. goal.

Trickey said the new market is producing much more data "and that was taking longer to process than ideal. So we've been working on improvements."

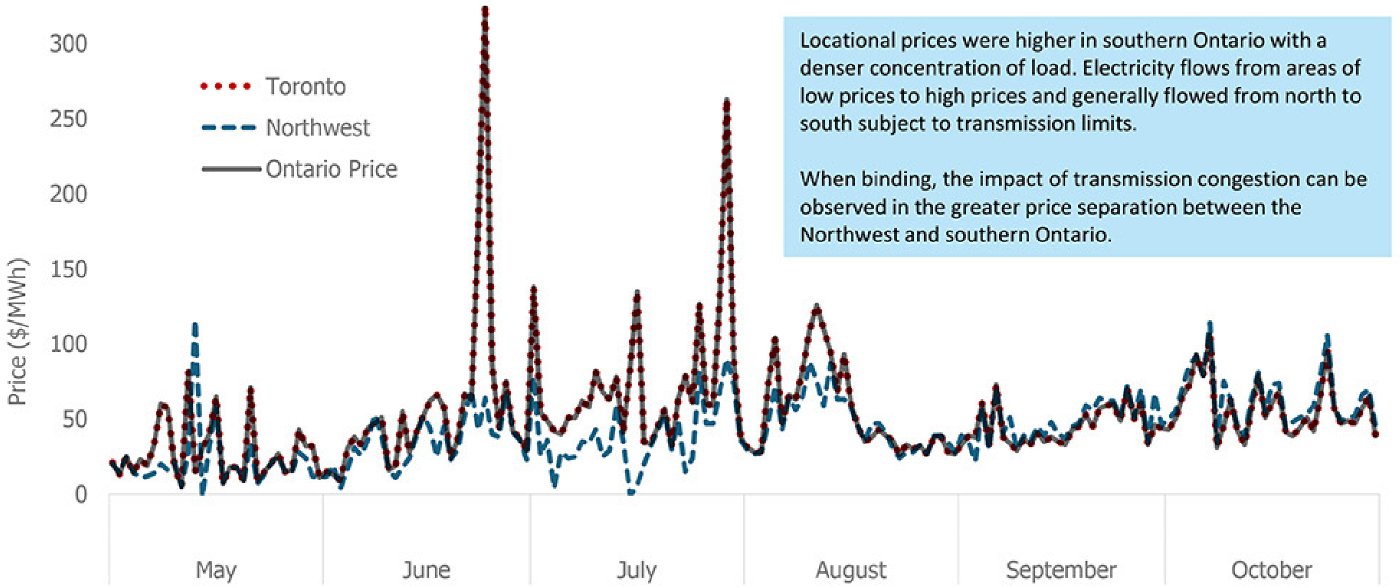
Of the settlement disagreements that have been resolved, the ISO said about 30% have been attributed to defects that have been corrected, with the remaining 70% of disputed statements confirmed as correct.

IESO is continuing to work through a backlog of disagreements, some of which are related to pending defect fixes. The ISO is notifying participants if there are delays in correcting settlements because of the pending fixes.

IESO officials said they had discovered



The summer brought higher demand, higher prices and greater price separation between day-ahead and real-time markets. | *IESO*



LMPs are similar throughout Ontario when there is little congestion. When demand — and congestion — is higher, as in summer, prices separate between the Northwest and the rest of Ontario. | *IESO*

several minor defects since August, including scenarios in which non-quick-start resources operating in combined cycle mode are receiving after-the-fact settlement mitigation calculated using the single cycle mode reference level.

The ISO also disclosed economic operating point (EOP) errors that may result in adjustments to real-time make-whole payments (MWPs) in resettlement statements posted Nov. 17 and Dec. 12. EOPs reflect the output a resource could have achieved based on its physical capabilities and LMP, under actual market conditions.

The impact of the resettlements will be small, "because they're all fairly specific scenarios impacting just certain types of resources," Trickey said.

The defects are separate from the MWP issues for which the ISO is proposing rule changes. (See *IESO Tweaking Make-whole Payments for Operating Reserves*.)

Advisory Forum

Trickey said IESO will continue its quarterly briefings on the Renewed Market's performance for the first year of operation.

In response to requests from market participants, the ISO also is creating a new group, the *Renewed Market Advisory Forum*, to discuss ways to improve the market.

Trickey said the group will focus on incremental improvements, not "long-term, evolutionary" changes.

"We've implemented this new market. Is everything working the way we thought it would, or as effectively as we hoped?" Trickey explained. "And if we're seeing some gaps — whether it's information that people need, or some parts of the system that aren't working as well as we hoped — this is where we would like to have those kind of conversations with participants that are really engaged in the market."

Candidates interested in participating should submit expressions of interest by Dec. 19 to *engagement@ieso.ca*. ■

Aging Oil Plants Face Unclear Future in New England as Winter Risks Rise

By Jon Lamson

Why This Matters

Several ongoing or anticipated market changes could have significant impacts on the fate of New England's aging fleet of oil-fired generators.

In New England, increasing winter reliability concerns are driving questions about how long the region's aging fleet of oil-fired power plants can, or should, remain on the system.

Power generation from oil has declined dramatically in New England since the start of the century. The oil plants that have remained on the system have run less frequently, mostly during tight winter periods when gas generators have limited access to pipelines.

Several high-profile oil units have already retired, and the large oil resources that remain face significant retirement risks.

Continued reliance on aging oil generators has real consequences: The units are among the dirtiest in the ISO-NE resource mix, both in terms of climate-warming emissions and local air pollution that can have significant health effects on nearby residents.

But ISO-NE forecasts that growing winter demand, coupled with obstacles to offshore wind development and limits to the region's gas supply, will increase the need over the next decade for dispatchable generators with fuel storage capabilities. This may force the region to keep the units online longer than many policymakers hoped, or to invest in adding dual-fuel capabilities to existing gas-only units.

Uncertainty remains, however, around when a significant spike in winter demand will materialize. And changes in the wholesale markets — including ISO-NE's ongoing capacity market overhaul, evolving Pay-for-Performance risks and the introduction of longer-duration reserve products — could also have significant effects on plant revenues, making it difficult to predict how long the resources will remain online.

"You see a lot of the owners of some of these oil facilities caught in between and not being able to see a clear picture as to whether the ISO, the states and other policymakers want to try to preserve those facilities or drive them into retirement," said Dan Dolan, president of the New England Power Generators Association.

"A lot of them have been driven into retirement or been driven into a place in which they are right on the cusp of financial viability," he said. "I, at this point, don't have a clear line of sight as to how some of those standalone large steam units are going to function."

Changing Economics

The New England oil fleet is old: Most of the oil-fired steam units were built in the 1970s. As cheaper, cleaner and more efficient sources of energy have come online, oil generation has declined dramatically, dropping from 18% of the total energy production in 2000 to 0.3% in 2024, according to ISO-NE.

The steepest decline occurred between 2000 and 2010. Over the past 10 years, annual oil generation has fluctuated, often following the severity of winter conditions.

But the region has continued to see retirements and a declining amount of oil capacity on the system. Between Forward Capacity Auctions 15 and 18, capacity supply obligations for generators running on distillate and residual fuel oil declined from over 4,700 MW to about 3,500 MW.

"Many of these units are at risk of retirement," ISO-NE noted in its draft 2025 *Regional System Plan*. "They run infrequently, are less efficient and are nearing the end of their economic life."

As the resources have run less frequently, they have become more reliant on capacity revenues, while low capacity clearing prices have pushed higher-priced generators out of the market, according to ISO-NE's Internal and External Market Monitors.

Potomac Economics, ISO-NE's External Market Monitor, wrote in its 2024 *annual report* that "the sustained low prices led to 760 MW of retirement bids from units with on-site fuel supplies clearing in FCA 18," which applies to the 2027/28 capacity commitment period (CCP).

With essentially no dispatchable generating resources in the region's interconnection queue, "it will be critical to retain a large share of the existing dispatchable generation and avoid mandating retirements of fossil fuel resources," Potomac wrote.

ISO-NE analyses have "made it clear that we need dispatchable resources, and we need a fairly significant quantity of readily available fuel for those dispatchable resources," said Brian Forshaw, principal at Energy Market Advisors and a longtime NEPOOL participant. He emphasized that his comments are not on behalf of any of his clients.

"The challenge is going to be how to identify what the value of retaining that capability is, and then developing some kind of a market mechanism, or a reserve product or whatever else to compensate them enough to keep them around," he added.

ISO-NE's Capacity Auction Reform (CAR) project, a major multiyear effort, is intended to help better align capacity procurements with actual reliability benefits.

The project proposes transitioning the RTO from a forward, annual capacity market, with auctions held three years prior to the relevant CCP, to a prompt, seasonal market, with auctions held about a month prior to each CCP, which would be divided into winter and summer seasons.

The effort also includes significant changes to how much capacity value ISO-NE assigns to different resource types. Under the current rules, the capacity market typically accredits resources based on an audited value intended to capture the maximum output they can provide. The methodology does not account for outage rates and maintenance requirements, which ISO-NE instead factors into its calculations for the installed capacity requirement.

Under the proposed CAR changes, resources would be accredited based on their marginal reliability impact value, which is intended to capture contributions to reducing energy shortfall during extreme model scenarios. Accreditation values would account for a wider range of factors, including resource outage rates, maintenance requirements, stored fuel and intermittency.

The changes could have major implications for the capacity revenues available to different resource types, though it is still early in the process to predict how the project will affect various resource classes.

"It is vitally important that the ISO-NE markets accurately signal which resources effectively support reliability and how much capacity is needed," Potomac wrote in its annual report. "This is necessary to avoid premature retirement of fuel-secure resources, incentivize generators to acquire inventory or firm fuel arrangements, and avoid overpaying for capacity that does not support reliability."

The changes to accreditation will likely be both positive and negative for oil generators.

Accounting for fuel storage appears likely to increase the accreditation values for oil units relative to other resources, and multiple participants involved in NEPOOL discussions also said the shift to a seasonal market may push prices up in the winter, providing an additional boost.

However, oil-fired steam resources tend to have higher outage rates and greater maintenance requirements, which will likely limit their accreditation values, regardless of their stored fuel capabilities or potential winter benefits.

The shift to a prompt market would also allow resources to submit retirement notifications much closer to each CCP; it would reduce this notification deadline from about four years to about one. This would enable participants to make retirement decisions based on more up-to-date information about the conditions of the market and their resources.

"There's so many variables and moving pieces to that design — it's going to be hard to get a clear picture until we see more about how all those pieces fit together," NEPGA's Dolan said.

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

Some stakeholders also expect future capacity prices to reflect a perceived increase in PFP risk. Capacity scarcity events trigger the PFP rules, which penalize resources with capacity obligations that fail to perform and reward resources that deliver more than their obligations.

Some oil-fired generators have racked up significant penalties during PFP events in recent years. The resources generally require significant advance notice to ramp up and come online, making them ill-suited to perform during unexpected scarcity periods.

"I think it's fair to assume that the higher Pay-for-Performance risk that people are now starting to perceive will work its way into the supply offers that will get submitted into the market," Forshaw said, adding that this will likely put "some upward pressure on prices."

New Mechanisms

Taking all factors into account, "the expectation is: Some of the older resources that do maintain significant inventories of residual oil are going to face challenges going into [the 2028/29] time frame and may consider submitting deactivation notices one year prior to the start of the delivery period," Forshaw said.

With looming retirement risks and ISO-NE's forecast that winter reliability risks will rise in the mid-2030s, it is important to begin discussions on potential solutions and new mechanisms, he said.

In a statement, ISO-NE noted it is evaluating "the potential addition of a longer response reserve product, such as a 60- or 90-minute reserve, to help manage uncertainties caused by the increasing variability of renewable generation and real-time system demand," which may provide additional opportunities for oil resources.

The RTO also recently established a new Regional Energy Shortfall Threshold (REST), which is intended to define an acceptable amount of shortfall risk in the region. It plans to use the threshold to evaluate risks prior to each winter and summer season, as well as in long-term assessments. (See *ISO-NE Proceeding with Shortfall Threshold After Positive Feedback*.)

It has yet to determine how it would select and develop solutions to mitigate risk if the threshold is violated.

Data from long-term assessments "will guide evaluation of whether the possibility of exceeding the REST in those time frames requires development of regional solutions to mitigate modeled risks and, if so, when to begin to develop solutions; these efforts would be signaled in future annual work plans," ISO-NE wrote in a statement.

The RTO has yet to deploy the threshold in long-term, forward-looking studies. ISO-NE's probabilistic modeling for the upcoming winter indicates the region is well short of the risk threshold. (See *ISO-NE Forecasts Minimal Shortfall Risk for Upcoming Winter*.)

Forshaw emphasized the importance of establishing the process for addressing REST violations well before they occur, noting that major market reform frequently is a multiyear process.

If studies show high risks of energy shortfall because of a lack of fuel, it could make sense to procure fuel, or another type of energy, that would "only be used when we're facing load shedding, rather than in the normal course of dispatch," he said.

Interest in Dual Fuel

Regardless of potential new mechanisms or the specifics of the accreditation changes, some of the region's aging oil generators may be nearing the end of their useful life. Resource owners that are willing to keep units online, waiting for a spike in capacity prices, may be unwilling to make large capital investments in the case of major mechanical failures.

This long-term outlook, coupled with the region's winter gas constraints, has driven some increased interest in adding dual-fuel capabilities to existing gas plants, enabling them to burn oil during winter periods when gas prices spike or the units are unable to access gas.

"Given the slowdown on offshore wind and the other changes at the federal level that have really slowed down the scale and the pace of other clean energy entry, there's been a lot of interest from state policymakers, ISO New England and others about exploring what capabilities exist out there for adding more dual fuel to make up this megawatt-hour gap that may be in front of us," Dolan said.

Potomac wrote in its report that adding on-site fuel storage to gas-fired resources is "likely the lowest-cost strategy for addressing winter reliability concerns in the near-term in light of the issues with offshore wind development."

However, there is uncertainty as to whether the states would allow the facility changes, or if the market would support the investments, Dolan said. He added that dual-fuel investments likely would require "over a decade of payback … and years of development to put it into place."

He noted that the tensions and contradictions between state and federal policy have created significant development challenges for a broad range of resource types.

"It's a really tricky environment, and I don't have a clear answer of what to do about that," Dolan said.

Clean Energy Solutions and Environmental Impacts

The decline in oil generation, and the replacement of inefficient oil and coal units with cleaner gas plants and renewable energy, has coincided with significant reductions in emissions from nitrogen oxides and sulfur dioxide, according to ISO-NE's 2024 emissions *report*.

The RTO notes that between 2015 and 2024, sulfur dioxide emissions declined by 82% and emissions from nitrogen oxides dropped by 42%. This compares to a 15% decline in carbon dioxide emissions.

Oil-firing power plants "are among the highest-polluting resources that we have," said Joe LaRusso, manager of the clean grid program at the Acadia Center. "Many of them are located in communities that are overburdened with air pollution as it is."

Nitrogen oxides and sulfur dioxide, along with fine particulate matter, are air pollutants associated with a range of heart and lung issues, child asthma, cancer, autoimmune diseases and neurological harm, *according to* the American Lung Association.

In Massachusetts, these pollutants were responsible for 2,780 excess deaths in 2019, *according to* Boston College researchers.

While it is difficult to attribute deaths to specific generation types or plants, the study notes that stationary sources, which include power plants, industrial facilities, and heating and cooking, were responsible for about 30% of fine particulate pollution in the state.

Concerns about health effects have motivated grassroots movements to block the development of new peaking plants. In Peabody, Mass., residents fought bitterly and, ultimately, unsuccessfully to stop the construction of a dual-fuel peaker, which came online in 2024.

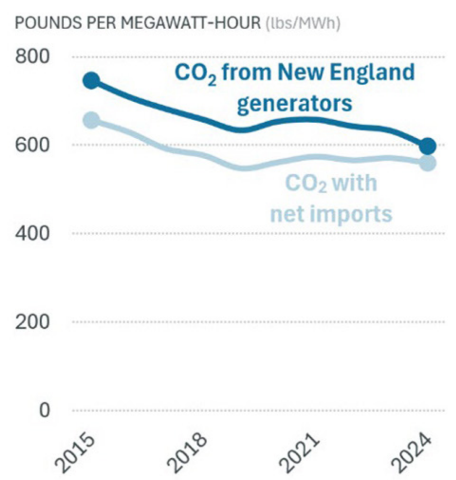
Any efforts to add oil capacity in the region, or to implement market mechanisms propping up these units, would likely be met with opposition from environmental groups.

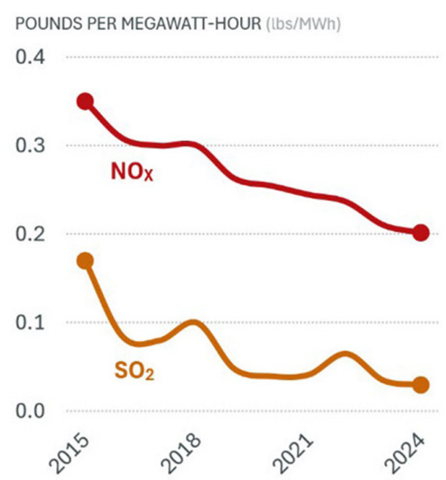
LaRusso said he is optimistic that three large projects nearing completion — Revolution Wind, Vineyard Wind and the New England Clean Energy Connect (NECEC) transmission line — will reduce the need for oil peakers, potentially pushing additional units into retirement.

NECEC is intended to supply the region with a consistent source of baseload power, while offshore wind performs best in the winter, when oil units run the most. Clean energy and consumer advocates also hope that aggressive demand-side initiatives will cause load to grow at a slower pace than is projected by ISO-NE.

In the long term, LaRusso said the resumption of offshore wind development in New England, the start of offshore wind development in Nova Scotia and increased bilateral power exchanges with Quebec could help the region meet growing winter demands while eliminating most of the remaining need for oil-fired generation.

"It seems that oil is going to follow the same path as coal, unless the demand curve starts rising so fast that batteries can't keep up," he said. "There are so many factors in play, but none of it appears to provide a rosy picture for an oil-firing plant." ■





New England annual average emission rates, 2015 to 2024 | *ISO-NE*

Mo. PSC Adds Consumer Protections to Ameren Large Load Rate Plan

By Amanda Durish Cook

The Missouri Public Service Commission unanimously approved a settlement agreement on rates for Ameren's large load customers that insulates ratepayers from most costs associated with supplying data centers' electricity needs.

The plan defines large load customers as those requiring a maximum 75 MW or more in monthly demand. Supply contracts under the rate would have minimum 12-year terms, with an option for a five-year load ramp period, making for potential 17-year contracts. The PSC sanctioned the rate Nov. 24 (*ET-2025-0184*).

Agreements would automatically extend for five-year increments unless customers provide a 36-month written notice that they intend to end or reduce their service. Customers who elect not to extend their service must pay exit and early termination fees.

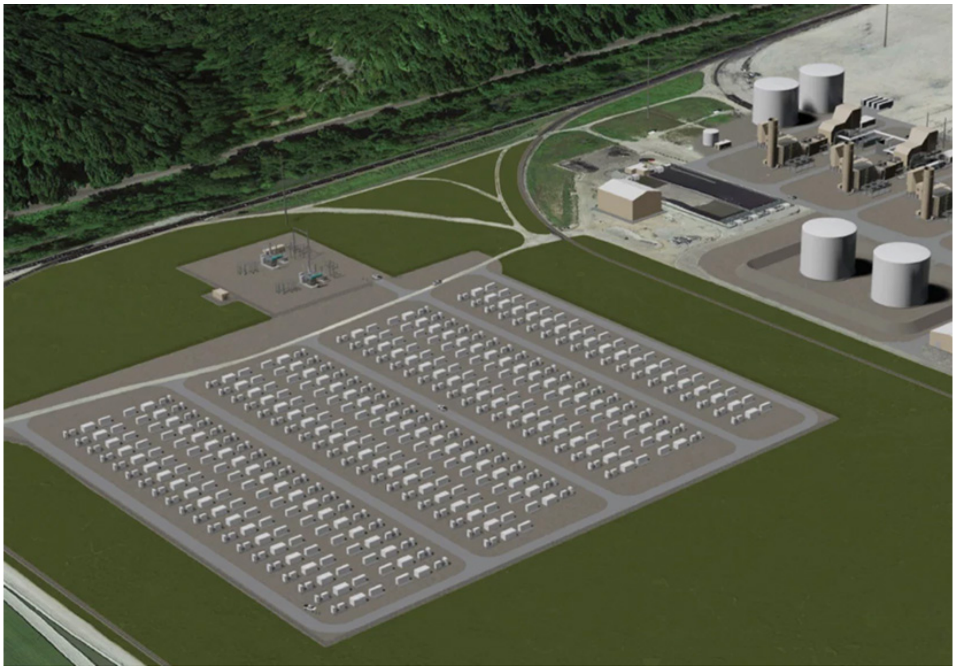
Large load facilities would be required to post collateral equal to two years of minimum monthly bills. Under the plan, they would be able to participate in Ameren's nuclear and clean energy programs through an expanded clean energy choice rider.

The rate also stipulates that a percentage of excess revenues from large customers be dispersed to benefit ratepayers, with half of the revenues earmarked for low-income customers. Finally, Ameren must evaluate the cost allocations for large loads and ensure that existing customers aren't paying for costs that should be paid by data centers and manufacturers.

The Missouri PSC said its approval of the agreement is "a significant step forward in implementing" 2025's Senate Bill 4. The omnibus energy bill enacted by the state legislature prevents large customers' "unjust or unreasonable" costs from bleeding into other customers' bills, among other directives.

"Efforts were also made to design a plan that was similar to other tariffs throughout the country, and across Missouri, ensuring Missouri can properly compete for the economic development benefits that these loads represent," the PSC said in a press release.

Several parties signed off on the settlement agreement, including Ameren, the PSC staff, Google, Sierra Club, Missouri Industrial Energy Consumers, Renew Missouri and Evergy.



Ameren Missouri's planned Big Hollow Energy Center includes 800 MW of gas generation and a 400-MW battery storage facility. The plant would replace the retiring Rush Island Energy Center. | *Ameren Missouri*

Why This Matters

Ameren Missouri is the latest utility to receive a large load rate plan from its public service commission. This one includes 12-year contract terms and a 75-MW monthly demand threshold.

The PSC's vote enshrined more consumer protections than originally were drawn up in the large load rate; an earlier version applied the rate to customers of 100 MW and above and included a 10-year contract term.

Jenn DeRose, a strategist with the Sierra Club's Beyond Coal Campaign in Missouri, said the rate plan is a "step in the right direction" to protect ratepayers from cost increases from data centers and discourage speculative moves from developers.

"Missourians are rightly concerned about the impacts of new data centers on their electric bills and communities, and they deserve protections," DeRose said in a statement. "How will customers be protected after Ameren spends billions of dollars of our money on new gas-burning power plants if the AI bubble bursts, the utility overbuilds power plants due to AI speculation, or AI data centers become significantly more efficient?"

Senate Bill 4 also requires utilities to replace retiring plants with dispatchable resources and mandates that utilities source at least 80% of their capacity with dispatchable generation.

That means large loads in Missouri likely would take a lot of natural gas-fired power. Ameren Missouri is planning a significant gas expansion, including the Castle Bluff Energy Center anticipated in 2027 and the Big Hollow Energy Center in 2028. The utility's 2025 preferred resource plan *includes* building 1.6 GW of new natural gas generation by 2030 and a total 6.1 GW by 2045. Ameren Missouri's next integrated resource plan filing is due to the commission in 2026. ■

FERC Allows MISO to Increase Project Count in Queue Fast Lane

By Amanda Durish Cook

FERC approved MISO's proposal to increase the number of generation projects it may study under its expedited interconnection queue lane from 10 to 15 per quarter.

The commission in a Nov. 25 order found that the increased quarterly project limit appears to be fair and aligns with its previous orders to speed up interconnection timelines reliably and transparently (*ER25-3543*).

FERC said it agreed with MISO that increasing project counts would help projects reach generation interconnection agreements faster and meet resource adequacy needs quicker. It said faster processing wouldn't "adversely affect" MISO's normal generator interconnection queue. (See *MISO Moves to Increase Quarterly Project Count in Queue Express Lane*.)

The change becomes effective Nov. 26, days before MISO kicks off acceptance of a second cycle of expedited generation requests.

The grid operator in late September filed with FERC to raise the quarterly rate, saying it could handle 15 project slots per quarter and could close the temporary queue process earlier than the originally planned Aug. 31, 2027, retirement date.

FERC endorsed MISO's interconnection fast lane in late July (ER25-2454). Since then, MISO has designated a 5.3-GW first cycle for study among a 26.5-GW pool of applicants. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class* and *26.5 GW of Mostly Gas Gen Compete for MISO's Sped-up Grid Treatment*.)

What's Next

MISO could conclude its generator interconnection fast lane earlier than its planned Aug. 31, 2027, sunset date with FERC authorizing a 15-project study count per quarter.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MISO has to date received 49 project applications for its expedited queue, with most of the megawatts coming from gas-fired generators.

MISO's Kyle Trotter told stakeholders the RTO discovered it could process the generation projects faster than it previously anticipated.

"We didn't see a reason not to try to go faster and expedite them even more. It doesn't go deeper than that," Trotter said at an October Interconnection Process Working Group meeting.

MISO Vice President of System Planning Aubrey Johnson told the Entergy Regional State Committee on Nov. 11 that the RTO believes the fast lane has met its objectives to accelerate resource additions.

However, environmental groups have challenged both MISO's and SPP's queue fast tracks at the D.C. Circuit Court of Appeals, arguing the processes are unduly preferential, allowing primarily fossil fuel generation to skip queue lines while ratepayers fund the grid upgrades needed to accommodate them. (See *Enviros Challenge MISO, SPP Queue Express Lanes*.)

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

FERC Declines to Decide Possible Ameren Bypass of MISO Tx Competition

By Amanda Durish Cook

FERC has dismissed Ameren's bid to gain exclusive rights to build nearly $2 billion of MISO regional transmission projects in the state free of competitors.

The commission in a Nov. 24 order refused to interpret Illinois' "first-in-the-field" doctrine as Ameren Illinois asked (*EL25-105*). It said the matter is best left to the state.

Ameren argued in a July petition that Illinois' first-in-the-field doctrine is the functional equivalent of a right-of-first-refusal law and gives it license to develop the Illinois portions of the lines in MISO's second, $22 billion long-range transmission plan. (See *Ameren Argues Exclusive Rights to MISO Illinois Competitive Tx Projects*.)

"We believe that the interpretation of Illinois' first-in-the-field doctrine is a matter of state law," FERC agreed. "We are concerned that issuance of a merits order on the petition at this time could conflict with subsequent Illinois court decisions or inappropriately interfere with the Illinois courts' consideration of Ameren's arguments."

FERC said its "declaratory orders to terminate a controversy or remove uncertainty are discretionary" and that it exercised its discretion not to take up the petition.

MISO has put two Illinois *projects* up for bid from the second long-rang portfolio: the $717.6 million portion of the $984.6 million Woodford County–Illinois/Indiana State Line 765-kV project; and the $940.1 million Sub T–Iowa/Illinois State Line–Woodford County 765-kV project. Ameren argued it should build both.

Among others, the Illinois Commerce Commission asked FERC to reject Ameren's petition and let the state deal with the issue.

FERC pointed out that Ameren already has asked an Illinois court to declare the first-in-the-field doctrine the functional equivalent of a right-of-first-refusal law and allow it to bypass MISO's competitive bidding.

FERC said it believed Ameren was asking it to construe the law for not only the two long-range transmission projects, but all future transmission projects in Ameren's Illinois service territory that "otherwise would be eligible to be included in MISO's competitive developer selection process."

Why This Matters

Ameren asked FERC to interpret Illinois' 'first-in-the-field' doctrine as the functional equivalent of a ROFR law. FERC refused, saying it would stay out of state affairs.

"In this sense, Ameren appears to request a categorical finding from the commission that the first-in-the-field doctrine will always result in a finding that the doctrine applies. But in each of the cases cited by Ameren in setting forth the doctrine, first-in-the-field determinations appear to have been made on the basis of a contemporaneous record," FERC wrote.

Ameren argued that Illinois had "broadly" applied the doctrine in bus service, telephone and pager service, for moving companies and for water and sewer service.

FERC concluded Ameren could not cite any case law where the ICC or Illinois courts applied the doctrine "in this manner."

"[W]e believe that Ameren's request implicates a question of first impression under Illinois law, and we are not the correct forum for such a novel application of state law," FERC wrote.

Ameren claimed it wasn't seeking an interpretation of Illinois law, just FERC's confirmation that the doctrine is an applicable law MISO should recognize. The ICC accused Ameren of "forum shopping," with FERC on its list as a means to crush transmission competition.

MISO disagreed with Ameren's claim that it was wrong to put the projects up for solicitation. The RTO said there wasn't a "binding determination from an Illinois court or other competent tribunal" to clearly show the doctrine is applicable to the projects. ■

Ameren Illinois

MISO to Debut Transmission Warning System in 2026

By Amanda Durish Cook

MISO is to roll out a new transmission warning declaration to give its members advanced notice when scarce transmission capacity is raising the risk of load shed.

Speaking at a Nov. 20 MISO Reliability Subcommittee meeting, Clayton Umlor, a MISO manager of reliability coordination, said a transmission emergency warning would establish "more transparency around transmission risk," especially when load loss is imminent.

The RTO wants to put the new system in place sometime in the first quarter of 2026.

Umlor said MISO would institute the warning only after it has exhausted all normal congestion management procedures without relief, including generation redispatch, transmission loading relief and reconfiguration plans. The RTO would also try deploying units' emergency ranges and calling on its emergency-only units and load-modifying resources before sounding the alarm, he said.

MISO intends to use the warning when 100 MW or more of load is at risk after those actions, or when it finds transmission facilities rated above 100 kV have post-contingent flow greater than or equal to 115%.

Umlor said MISO would also issue warnings when a reliability coordinator believes "system conditions warrant heightened awareness of potential transmission risk," such as when load is being served radially due to a forced transmission outage or when a real-time flow of a transmission facility rated more than 100 kV is expected to exceed 100% of transfer capability.

The RTO would call off warnings once risk recedes.

Umlor said the new warnings would require software changes for its operator interface and some stakeholder training.

"We want this to be a meaningful communication tool," Umlor said, adding that MISO doesn't want to issue the warnings so frequently that it becomes a "boy who cried wolf" situation.

He asked stakeholders to provide opinions on MISO's proposed 100-MW threshold.

The Bottom Line

MISO wants a new transmission emergency warning system in place in early 2026, a change instigated by the May 2025 load shed event in greater New Orleans.

'A Lot of Stakeholder Confusion'

The new warning category is the latest change MISO is pursuing after a May 2025 load-shedding event in New Orleans where 600 MW was forced offline abruptly to avoid exceeding an interconnection reliability operating limit (IROL) on Entergy's transmission system. (See *MISO Mulling New Way to Convey Spate of Advisories in South*.)

MISO has said an IROL "is the point when operational congestion becomes a reliability risk; crossing it isn't just a violation — it's a systemwide emergency."

The RTO told its Board of Directors following the blackout that it could

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have done more to convey the danger it perceived ahead of time. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

An Entergy representative at the RSC meeting said MISO's designated actions during close calls aren't always consistent.

Entergy associate general counsel Matt Brown said one shift of MISO operators could make one decision on a transmission plan of action while another shift could revoke that decision, even though criteria and conditions are unchanged.

"What it leads to is a lot of stakeholder confusion about what the risk level might be," Brown said.

Brown said he understood MISO operators are under "tremendous pressure," but added they sometimes make ambiguous declarations or split-second decisions the RTO struggles to explain afterward.

Umlor reiterated that the warning system is a "tool for communication that should be used infrequently enough that it is meaningful." He said the set of criteria should be clear enough that the warning conveys real and present danger. MISO must be "vigilant to make this calibrated properly," Umlor said.

Bill Booth, a consultant to the Mississippi Public Service Commission, asked if the warnings would come with any corrective actions for members.

"What's the value of this warning if it doesn't come with a directive?" Booth asked. He said when MISO delivers a capacity advisory, for instance, it comes with zero instructions.

Umlor said requests for action would come separately from MISO and not be tied to the warnings themselves.

John Harmon, MISO senior operations director of reliability, said the grid operator isn't looking to change the existing action plans that it and utilities have in place — or their approach to public appeals for conservation.

Harmon said the intent is to "create an additional risk trigger instead of going straight to an emergency."

Because transmission emergencies can involve shedding load, he said, it's useful to add a layer of communication before outages that other MISO members can see. He added that MISO communicates directly in real time with utilities directly tied to the risk.

MISO has been *declaring* transmission and capacity advisories — mainly for its South region — since the springtime load shed.

Shedding Timed IROL Analyses

Relatedly, MISO plans to expand its IROL study timeline so it isn't pressed to evaluate potential transmission emergencies in 15 minutes or less.

Harmon said the RTO would remove a 15-minute time limit to conduct cascade analyses from its emergency transmission procedures.

The grid operator's current rules require it to complete an analysis on the possibility of cascading outages within 15 minutes before declaring a temporary IROL.

Harmon said MISO would be removing "an artificial time limit" and that additional minutes would allow it and its transmission owners to study, agree on and implement mitigation strategies before declaring a temporary IROL.

MISO said it's "overly prescriptive" to assign a specific time limit on conducting studies. While the limit is "well intentioned," it could rush decision-making and cause it to declare an IROL too quickly, especially in situations where load shed is pre-contingent, the RTO said. ■

Former Ontario Power, NRC Leaders Join NYPA Nuclear Effort

New York Seeking to Develop at Least 1 GW of Advanced Nuclear Generation

By John Cropley

New York is adding new leadership to its advanced nuclear energy initiative: Todd Josifovski, director of the $13 billion overhaul of an Ontario nuclear power facility, and Christopher Hanson, who chaired the U.S. Nuclear Regulatory Commission during the Biden administration.

The New York Power Authority announced the appointments Dec. 1.

Josifovski will become NYPA's senior vice president of nuclear energy development Jan. 1. Hanson will serve as a senior consultant on financing and the federal permitting process.

New York Gov. Kathy Hochul (D) in June directed NYPA to develop at least 1 GW of new advanced nuclear generating capacity. (See *N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility*.)

Popular acceptance of nuclear energy has increased in recent years, and President Donald Trump has ordered the federal regulatory process to be accelerated and streamlined, but the process of building a new commercial reactor remains potentially slow, expensive and complex. Josifovski and Hanson are expected to help New York with this.

Josifovski has worked in clean energy and nuclear power development for more than 20 years, including at Ontario Power Generation, where he was a senior manager and then director of the refurbishment of the four-unit Darlington Nuclear Power Station. That project is nearing completion at an expected cost of $13 billion CAD. Josifovski currently is vice president of development at Peak Power.

Why This Matters

New York is adding deep experience to the team pursuing an ambitious nuclear goal.

New York's R.E. Ginna Clean Energy Center is the smallest and second-oldest commercial nuclear reactor in operation in the U.S. | *Constellation Energy*

Hanson joined the NRC as a commissioner in 2020, during Trump's first term, and served as chair from Jan. 20, 2021, to Jan. 20, 2025. He continued as a commissioner until Trump fired him June 13.

His *NRC bio* notes that he previously accrued three decades of public- and private-sector experience in the nuclear fuel sector.

NYPA President Justin Driscoll said Josifovski and Hanson would play important roles in moving the state's nuclear initiative forward.

"Todd has managed the development and execution of more than 7 GW of clean energy and nuclear projects, and his approach integrates technical rigor with pragmatic risk management, stakeholder engagement and a strong commitment to operational excellence," Driscoll said. "Additionally, Chris' extensive experience on the federal level will prove invaluable to NYPA as we navigate this next chapter and form lasting partnerships that will deliver firm, emission-free generation for New York state."

New York has a challenging path ahead as it tries to expand and upgrade its grid. Its renewable energy buildout was behind schedule even before Trump began his second term, and his policies are expected to further impede progress.

As a result, the aging fossil fleet that policymakers want to phase out remains indispensable: 25% of total statewide generating capacity is fossil-fired plants that are more than 50 years old.

New York's four commercial reactors — on the opposite shore of Lake Ontario from Darlington — are a combined 198 years old and draw half a billion dollars a year in ratepayer-funded subsidies to continue operation. The state expects to rely on their output into the middle of the century. Meanwhile, state policymakers expect to need more electricity as New York decarbonizes transportation and buildings.

The confluence of factors is such that NYISO opened its *2025-2034 Comprehensive Reliability Plan* with this warning: "New York's electric system faces an era of profound reliability challenges as resource retirements accelerate, economic development drives demand growth and project delays undermine confidence in future supply."

The existing nuclear fleet provided 21% of the power produced in-state in 2024, NYISO said in the report *issued Nov. 21*; a scenario in which the four reactors are retired would create shortfalls in summer and larger shortfalls in winter.

The challenge facing NYPA — and now Josifovski and Hanson — is to move the advanced nuclear initiative forward not just quickly but safely and affordably, and with a politically acceptable siting mechanism.

NYPA has issued requests for information from potential developers and potential host communities on how best to do this. (See *Wanted: N.Y. Community Eager to Host Nuclear Reactor*.) Their responses are due Dec. 11. ■

NYISO Begins to Discuss Demand Curve Reset Process Changes

By Vincent Gabrielle

Discussion about potential *changes* to the NYISO demand curve reset (DCR) process dominated a recent Installed Capacity Working Group meeting and will likely take up more oxygen in stakeholder meetings throughout the coming year.

"This project has the potential to deliver transformational changes to the market in the face of evolving grid conditions," Michael Ferrari, NYISO market design specialist in capacity and new resource integration, told the working group Nov. 17 in presenting the project's kickoff.

The Capacity Market Structure Review project identified the DCR as an area that needed improvement. The improvement project was prioritized for 2026, meaning NYISO has budgeted resources and labor hours for it.

Stakeholders have long complained that the DCR does not provide adequate price signals for new investment, value reliability contributions or provide sufficient consideration of long-term reliability impacts. During the latest DCR, stakeholders debated whether NYISO's preferred proxy unit, a two-hour battery system, was appropriate or reflective of what might enter the market. In addition, stakeholders said the DCR has a steep learning curve, requires a lot of stakeholder engagement and provokes contentious debates during working group meetings.

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Though Ferrari's presentation noted all these concerns, "it doesn't seem like the concerns expressed by Con Edison are in here," a representative of the company said. "There have been multiple conversations on our end about concerns of higher costs to customers."

Ferrari said stakeholder feedback highlighted in his presentation was "not a comprehensive list," though the omission of price considerations was indeed an accident.

The presentation indicated NYISO would study how to improve or refine the definition of the proxy unit used to undergird the DCR process. The ISO also would look at restructuring the development of the net cost of new entry of the proxy unit, which sets prices for the curve; look at alternative curve slopes; and possibly develop a technology-agnostic approach to net CONE.

Stakeholders asked what a "technology-agnostic approach" meant with respect to net CONE. Ferrari said it meant NYISO was considering not choosing one specific unit to serve as the proxy for new generator entry to the market.

The ISO plans to issue a draft Issue Discovery Report at the ICAP Working Group's Dec. 16 meeting. It will present the group with a detailed proposal of initial market design enhancements for consideration at a later meeting. ■

Why This Matters

The demand curve reset sets capacity prices every four years. Because the DCR itself is often contentious, it is likely the project to change the process will dominate stakeholder discussions in the coming year.

FERC Approves PECO-Amazon Transmission Agreement for Pa. Data Center

By Devin Leith-Yessian

FERC has approved a transmission security agreement between PECO Energy and Amazon for a data center planned in Falls Township, Pa. (*ER25-3492*).

The data center is among the first in a $20 billion pool of investments Amazon *announced* it is making across Pennsylvania. It would not be co-located with any generation and would receive retail service under a schedule approved by the Pennsylvania Public Utility Commission, FERC said in an order issued Nov. 21.

The agreement includes a set of provisions intended to prevent costs associated with the interconnection from being shifted to other customers if the data center does not materialize. It lays out a ramp schedule on which the load is expected to come online, with shortfall payments if those milestones aren't reached and termination fees if the load is permanently reduced. There is a committed revenue contribution that sets the baseline Amazon must pay, equal to 80% of what a load-serving entity would pay to serve 80% of the monthly load and billing — though that is subject to a customer shortfall event liability cap.

Monarch Energy Development and Constellation Energy argued the agreement should be considered on its own and not as setting precedent on other large load interconnections. The former said there are parallels between the agreement and a pending proposal from Commonwealth Edison seeking to require large loads to obtain a TSA.

Monarch also encouraged the commission to explore whether the PECO-Amazon agreement adheres to cost-causation principles, overestimates the risks large loads present to other customers and conflicts with the federal government's goal of developing the infrastructure needed to support artificial intelligence.

The PJM Independent Market Monitor argued the agreement should not be approved unless it could be demonstrated that the data center would not adversely impact transmission reliability and resource adequacy. It also faulted the agreement for not considering the implications for energy and capacity market costs the added load could present for customers across PJM.


Amazon data center | *Amazon*

Throughout PJM's Critical Issue Fast Path (CIFP) process focused on large load interconnections, Monitor Joe Bowring held that the RTO should not be obligated to accept load it cannot serve reliably, a stance the IMM extended to LSEs in comments on the TSA.

"Despite the protections included in the TSA, it is not just and reasonable to allow the interconnection of this large new data center load when it has not been demonstrated that either PECO or PJM has the capacity available to reliably serve this load," the Monitor wrote.

It also filed a complaint against PJM on Nov. 25 arguing that its CIFP proposal would require it to accept large load interconnections it cannot reliably serve, degrading the quality of service for existing customers while imposing higher costs (*EL26-30*).

The commission determined the agreement can be limited to ensuring that Amazon contributes to PECO's transmission revenue requirement without needing a demonstration that the load will not affect reliability.

"Given that the IMM raises no issue with the terms of the transmission security agreement itself, but rather raises concerns with the provision of service to the data center under PECO's retail tariff and the provision of transmission service to large loads generally, the IMM's concerns do not provide a basis upon which to reject the transmission security agreement," FERC wrote. "We also note that the Pennsylvania commission retains authority to establish terms of retail service between Amazon and PECO, including retail consumer protection provisions."

Commissioner Judy Chang concurred, writing that the agreement includes some consumer protections and recognition of state authority over retail rates, while urging the commission to develop a comprehensive framework for assigning transmission upgrade costs.

As large load interconnections with significant impacts to the grid become more common, she said the commission's "higher of" policy could serve as a framework for determining how those costs could be allocated. Under that model, large loads pay the greater of the embedded or incremental cost rates, which she wrote would ensure that a large load pays for network upgrades it triggers.

"It may be time for the commission to proactively consider how to guarantee sufficient customer protections, such as the 'higher of' pricing policy, to ensure that we do not outsource our customer protection responsibility to bilateral agreements by the utilities we regulate," she wrote.

She wrote it's especially important for agreements between utilities and large customers to recognize the contours of state jurisdiction, particularly when the Mobile-Sierra public interest standard of review is applied, as in the PECO and Amazon agreement.

"Given the potential magnitude of new transmission investment triggered by large load additions, concerns about costs are increasingly spilling into commission proceedings, raising complicated jurisdictional and policy questions with significant implications for both state and federal regulators," she wrote. "This critical affirmation will help ensure that the commission's acceptance of the agreement and possible similar agreements in the future recognizes and preserves states' essential role in protecting retail customers." ■

Virginia SCC Approves Rate Increase, New Large Customer Class for Dominion

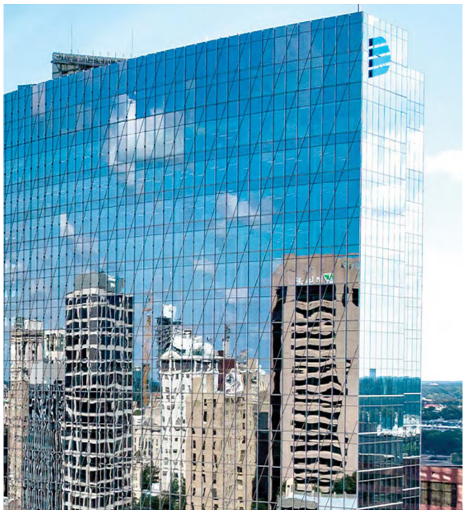
By James Downing

The Virginia State Corporation Commission trimmed Dominion Energy's rate increase and approved its plan to create a new rate class for large load customers like data centers.

In an *order* issued Nov. 25, the SCC approved the new GS-5 rate class to become effective Jan. 1, 2027. The new class will help insulate other customers from the rapid buildout of infrastructure needed to serve new data centers, the commission said. Any customers with demand of 25 MW or greater and a load factor of at least 75% will go into GS-5.

Customers in the new class will sign electricity service agreements that last 14 years. If they leave Dominion's service early for a competitive service provider (CSP), they will have to pay an exit fee that covers 85% of the contracted demand's distribution and transmission costs and 60% of its generation costs.

"Dominion must consider aggregate forecasted demand over a long-term planning period, must plan to meet those needs with supply resources that typically require many years to develop, and must construct generation to be ready to serve high load customers who are eligible to select a CSP in the future," the SCC said in its order. "Accordingly, the commission finds that the minimum generation demand charges shall apply to these new shopping customers."



Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

That will reasonably recover the costs of infrastructure Dominion built to serve such customers even if they retire early, the commission said.

GS-5 customers can reduce their capacity during the ESA term by up to 20% at no cost and an additional 30% if another customer agrees to assume the associated capacity. Each capacity reduction requires a 36-month notice.

The SCC also rejected Dominion's requested base rate increases of $822 million for 2026 and $345 million for 2027, instead approving $565.7 million in 2026 and $209.9 million in 2027. Those translate into $11.24 more on a typical residential customer's bill in 2026 and $2.36 more on monthly bills in 2027, which are 23.7% and 51.2% lower than what Dominion had requested, respectively.

The SCC also approved a higher return on equity for Dominion, raising it from 9.7% to 9.8%, which is below the 10.4% it requested.

"As the utility regulator, we are obligated by law to set a revenue requirement that affords the company an opportunity to recover reasonable and prudent projected costs and earn a reasonable rate of return," the SCC said. "In this case, that has resulted in an increase in rates, but not to the extent requested by Dominion."

In another *order* issued Nov. 25, the SCC approved Dominion's Chesterfield Energy Reliability Center (CERC), a 944-MW natural gas plant made up of four GE Vernova 7F combustion turbines. The turbines will be built in the footprint of a retired coal plant and alongside two existing combined cycle power plants.

The plant is the first natural gas-fired generator that the SCC had to evaluate since the Virginia Clean Economy Act was passed in 2020. Dominion said it was needed to keep pace with demand growth. The plant will cost the average residential customer 60 cents on their monthly bill.

"This case therefore is not about choosing CERC over compliance with the VCEA (or CERC versus renewable generation, demand-side management or batteries, for that matter). Instead, the commission is called upon to determine whether a 'threat to the reliability or security of electric service to the utility's customers' exists, such that the CERC project is required to obviate such threat," the SCC said in its order. "As discussed herein, the evidence in this case clearly establishes that there is an imminent reliability threat for Dominion and its customers and that the CERC project addresses that threat in a manner that is in accordance with the public interest and the VCEA."

The Bottom Line

The SCC approved a new rate class for large customers including data centers and authorized Dominion to build new natural gas combustion turbines to meet rising demand driven by those new customers.

While the commission acknowledged that some of the forecast load growth for Virginia and the rest of PJM may be overstated, it also said the demand for power is certainly on the rise. It cited the spiking capacity prices in the RTO, as well as NERC reports that PJM could run short of reserves in extreme weather in the second half of this decade.

The CERC order was opposed by environmental groups including Clean Virginia, which called the approval disappointing.

"Despite major flaws in Dominion's application and planning process, the commission granted approval to a gas plant that breaks Virginia's commitments to clean air, further drives up electric bills and which would not be necessary absent the gluttonous energy demands of Big Tech companies," Executive Director Brennan Gilmore said. "If this is the decision the commission came to under existing rules, then it is upon Virginia's elected leaders to better align these rules with the interests of all Virginians." ■

Departing N.J. Governor Touts Clean Energy to Solve State Power Woes

Murphy's Master Plan Calls for Widespread Electrification

By Hugh R. Morley

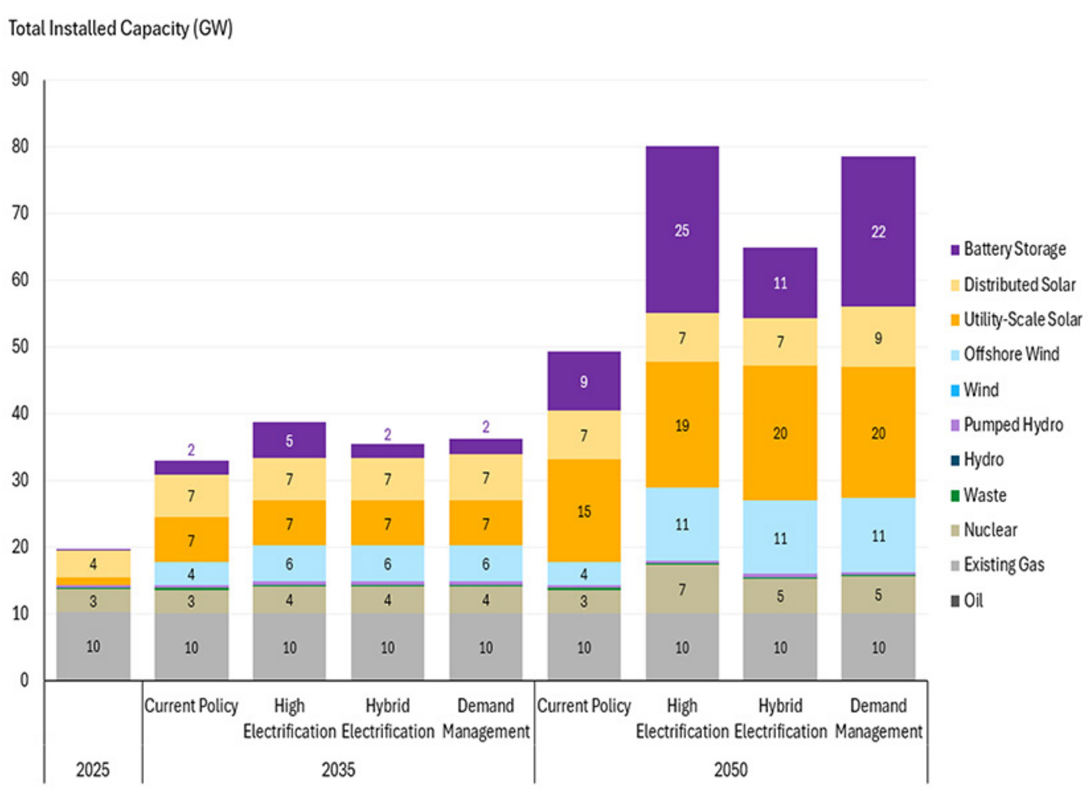
New Jersey should continue to pursue a strategy of heavy reliance on clean energy to head off the state's looming energy shortage, with no increase in natural gas generation, says a new plan released by outgoing Gov. Phil Murphy (D).

The governor's *2024 Energy Master Plan* pays little heed to critics who say the state's pending energy shortfall requires renewed consideration of new natural gas plants. Instead, it outlines a future that is heavily dependent on clean energy, along with building electrification and enhanced use of electric vehicles.

The plan says the "pillars of planning and decarbonization" should provide the state with stability in the face of a future in which the PJM region — which includes New Jersey — faces annual demand increases "for the first time in two decades." That includes a forecast of 32 GW in additional peak demand in the PJM region by 2030 and a 58 GW increase by 2035.

"Any future aligned with the state's economic, energy, and climate goals will require accelerated clean energy generation — solar, wind, advanced nuclear, green hydrogen and battery storage," according to the plan. "Doing so will reduce electricity imports, boost in-state generation, grow clean energy jobs, increase resource diversity and support long-term cost stability."

The clean energy recommitment by Murphy, who leaves office in January 2026, comes amid heated debate about how to speedily increase the state's affordable energy generating structure to meet accelerating demand from artificial intelligence companies and data centers. Some politicians argue that the potential electricity crisis is so severe that the state should adjust its carbon emission commitments and consider expanding its natural gas generating fleet.



Total installed capacity across scenarios | *New Jersey Energy Master Plan*

Why This Matters

The state "is projected to rely on investments in solar, battery storage, and offshore wind to support growing demand" and meet its goal of zero emissions by 2035, the plan says.

Former Gov. Chris Christie (R) said at an Oct. 28 energy conference organized by the New Jersey Business & Industry Association that the winner of the November gubernatorial election should look to "open two or three new natural gas generation plants as quickly as possible" (See *N.J. Forum Explores Solutions to Looming Energy Shortfall*.)

U.S. Rep. Mikie Sherrill (D), the eventual winner, said during a debate in October that she would "improve our gas generation in the state." In a Nov. 20 *television interview*, she said: "We need to make sure our gas generation, which is about 40% of our production right now, is more, is modernized, so we can drive down carbon emissions while driving up much of the generation from gas generation."

The New Jersey League of Conservation Voters released a statement calling the plan "an affordable energy road map at exactly the right moment."

No Plans for Gas Plant Construction

Murphy, releasing the plan, called it the "culmination" of his two-term effort to tackle "the challenges of energy affordability, supply and demand, and climate change."

Murphy's staff, in a briefing on the plan, said it considers gas generation to be important as a "dispatchable resource" but contains no prescription to build more gas generators in the state.

The state "is projected to rely on investments in solar, battery storage and offshore wind to support growing demand" and meet its goal of zero emissions by 2035, the plan says. "Total gas generation declines by 2050 across all [the plan's proposed] mitigation scenarios … driven by the expansion of renewable and nuclear capacity."

The plan adds that the strategy will reduce the amount of imported electricity as battery storage, nuclear, wind and solar — utility-scale and distributed — expand to meet the new demand.

Changing Energy Landscape

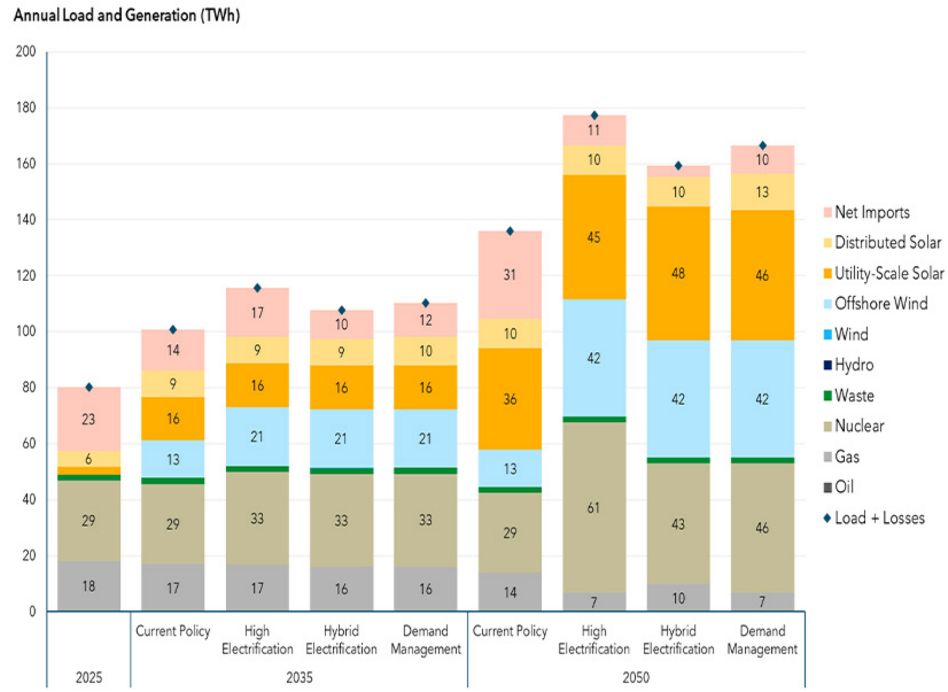
What effect the master plan will have is unclear given that the transition from Murphy to Sherrill will take place in January. A Murphy staffer said the plan offers a "compendium" of what the state has done under his tenure, and it is up to Sherrill whether to incorporate the suggestions into her own strategy.

Sherrill's transition team did not respond to a request for comment.

Murphy has come under criticism that his focus on developing a robust wind sector — he set an offshore wind goal of 11 GW — left the state short on new generating sources when the bet on wind failed. The state has no active wind project after developer Ørsted abandoned its two Ocean Wind projects in 2023 due to logistical issues and rising costs. A third, Atlantic Shores, withdrew amid the Trump administration's opposition to offshore wind. (See *Developer Shelves Atlantic Shores, Seeks to Cancel ORECs*.)

A release from Murphy's office said the master plan offers a "flexible, adaptive framework of 'no-regrets' strategies and policies" that can adapt to the "changing energy landscape." Murphy's staff said the concept means the state can pursue them, and any investment, without wholly committing the state to the strategy if the environment changes and a direction shift becomes necessary.

The strategy includes "doubling down on the state's successful solar programming, while at the same time expanding programming to deploy battery storage projects, clean firm generation options, virtual power plants, as well as exploring the potential for advanced nuclear resources in the state," the plan says.



Annual energy balance by scenario | *New Jersey Energy Master Plan*

Reliable and Modern Grid

The master plan was compiled by Energy + Environmental Economics (E3) through research, modeling and stakeholder input. A draft plan outlined three different scenarios that varied in how aggressive their pursuit of the state's emissions reductions goals would be, and compared them with the scenario if the state did nothing. That comparison evaluated the effect on electricity rates.

The plan predicts that electricity use will increase by between 66 and 109% by 2050, depending on which scenario is pursued. It reports that customers wholly using electric appliances and vehicles will see a $50 increase in their monthly energy costs from 2025 to 2035. Customers using mainly gas would see a $95 increase, while those using a hybrid of both would see a $59 increase.

The completed plan does not recommend which of the three scenarios the state should adopt but instead makes a series of recommendations for strategies and policies. They include "accelerating clean energy deployment" and "expanding decarbonization and efficiency programs."

"Not only does more efficient equipment provide lower bills for program participants, it reduces overall electric demand, thereby taking pressure off the wholesale power market and reducing emissions from both the power and buildings sectors," the plan states.

The plan calls for moves to ensure a "reliable and modern grid," and for the state to continue pursuing transportation electrification. Although the state, with 260,000 EVs on the road, is nearly 80% of the way to reaching its target of 330,000 EVs, the plan does not suggest a new one.

The plan also calls for the state to enhance "regional coordination and advocacy."

"New Jersey must continue to actively engage with PJM and neighboring states to ensure grid reliability, affordability and accelerate clean energy integration," the plan says. "Additionally, the state should continue to take steps to have more formal involvement in the PJM decision-making process to ensure that its policy objectives are reflected in PJM's market rules and policies." ■

Energy Secretary Wright Issues 3rd Order Keeping Eddystone Open

By James Downing

U.S. Secretary of Energy Chris Wright has extended the *order* under Section 202(c) of the Federal Power Act to keep Constellation Energy's Eddystone Generating Station in Pennsylvania running through this winter.

Orders under the law are effective for 90 days. This is the third order issued in 2025 to keep the dual-fuel power plant running. (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online*.)

"Thanks to President Trump's leadership, the Department of Energy is using all tools available to keep the lights on and heat running for the American people," Wright said in a statement. "This emergency order is needed to strengthen grid reliability and will help provide affordable, reliable and secure power when Americans need it most."

PJM has been charging all the load in its market to pay for the power plant under a tariff FERC approved this summer. (See *FERC Approves Cost Allocation for Eddystone Emergency Order*.)

Wright also recently extended the 202(c) order keeping Consumers Energy's J.H. Campbell coal plant open in Michigan. (See *DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open*.)

The Campbell and Eddystone orders have been challenged in court by state authorities and environmental groups. The former case is further along, with the first substantive briefs due Dec. 19.

Eddystone was scheduled to retire before the summer. PJM dispatched the units during heat waves in June and July, DOE said. The current order will keep the plant running until Feb. 24, 2026. DOE noted the RTO set a winter peak in January 2025.

"Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction and characteristics of resources in PJM's interconnection queue," DOE's order said. "Upcoming retirements, including the planned retirement of the Eddystone units, would exacerbate these resource adequacy issues."

In total, the two units subject to the order generated 26,434 MWh between June 2025 and September 2025, DOE said in the order.

PJM has been dealing with rising demand and retirements in recent years. DOE's order said that "will continue in the near term and [is] also likely to continue in subsequent years."

"This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety," the order said. ■

Eddystone Generating Station in Eddystone, Pa. | *Constellation*

Market Monitor Files Complaint Over PJM Large Load Interconnections

By Devin Leith-Yessian

The Independent Market Monitor has filed a *complaint* asking FERC to determine that PJM has the authority to hold off on large load interconnections if they would jeopardize transmission security or resource adequacy (*EL26-30*).

"The question is clear. If PJM has an obligation to provide reliable service to all PJM loads, is it just and reasonable for PJM to add new loads that it cannot serve reliably? The answer to that question is no," the Monitor wrote in the Nov. 25 complaint.

It argues the proposals PJM and stakeholders made in the recent Critical Issue Fast Path (CIFP) process rest on the faulty assumption that the RTO does not have the ability to turn away large loads even when there is not sufficient capacity to serve them.

The Monitor's proposal, which received the second-greatest amount of support out of a dozen, would establish a queue for large loads, preventing them from coming online until they could be served reliably. The queue could be bypassed by loads bringing their own generation, with an expedited study process for those resources. (See *PJM Stakeholders Reject All CIFP Proposals on Large Loads*.)

"The solutions offered by PJM and most stakeholders simply assume that PJM must agree to add large loads to the system when the loads cannot be served reliably because PJM does not have the required capacity resources. From another perspective, the position of PJM and market participants assumes that PJM does not have the authority to require that large new data center loads can be served reliably before those loads are added to the system," the Monitor wrote.

Why This Matters

The complaint makes the case that if a large load cannot be served while maintaining the reserve margin, PJM should be able to deny interconnection until that can be accomplished.


Monitoring Analytics President Joe Bowring | © RTO Insider

The Monitor wrote that data center load is the primary driver of a reliability gap that is expected to grow over the coming years. It states that the 2026/27 Base Residual Auction (BRA) was short of the reliability requirement by 200 MW; those tight conditions also caused a $7.3 billion, or 82.1%, increase in auction revenues which would not have occurred without that load growth. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

PJM spokesperson Jeff Shields said the RTO is reviewing the complaint and does not have any comments before it submits a formal response.

"We have said that higher pricing is being driven by a supply and demand crunch, with the dominant driver on the demand end being data center electricity needs," Shields added.

Monitor Joe Bowring told *RTO Insider* the complaint would clarify PJM's authority to its Board of Managers before it decides on how to proceed with filing governing document changes in the wake of the CIFP.

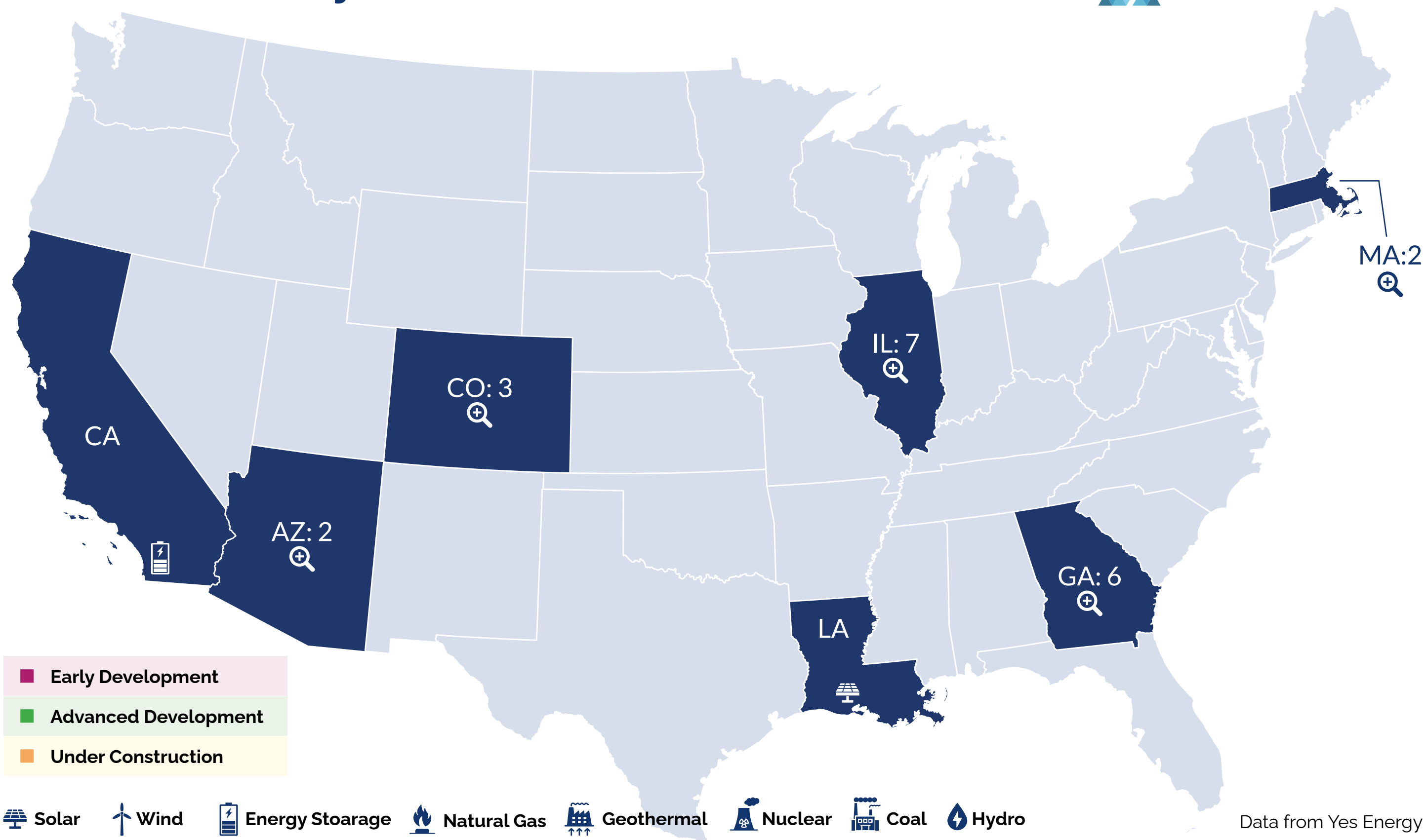
The complaint makes the case that Order 2000 requires RTOs to maintain a reliable transmission network, which PJM has accomplished through its capacity market and Regional Transmission Expansion Plan. If a large load cannot be served while maintaining the reserve margin, PJM should be able to deny interconnection until that can be accomplished.

"Interconnecting large new data center loads when adequate capacity is not available is not providing reliable service. The obligation to provide service is the obligation to provide reliable service. The obligation to provide service is not met if customers are simply interconnected without adequate resources to meet their demand," the Monitor wrote.

The Monitor made similar comments on a transmission security agreement between Amazon and PECO, arguing that utilities should be required to demonstrate there is sufficient capacity and transmission capability before bringing large loads online. The commission's Nov. 21 order determined such a demonstration is not needed for agreements between customers and utilities (*ER25-3492*). (See related story *FERC Approves PECO-Amazon Transmission Agreement for Pa. Data Center*.) ■

Generation Projects Added in the Past Week

YES ENERGY



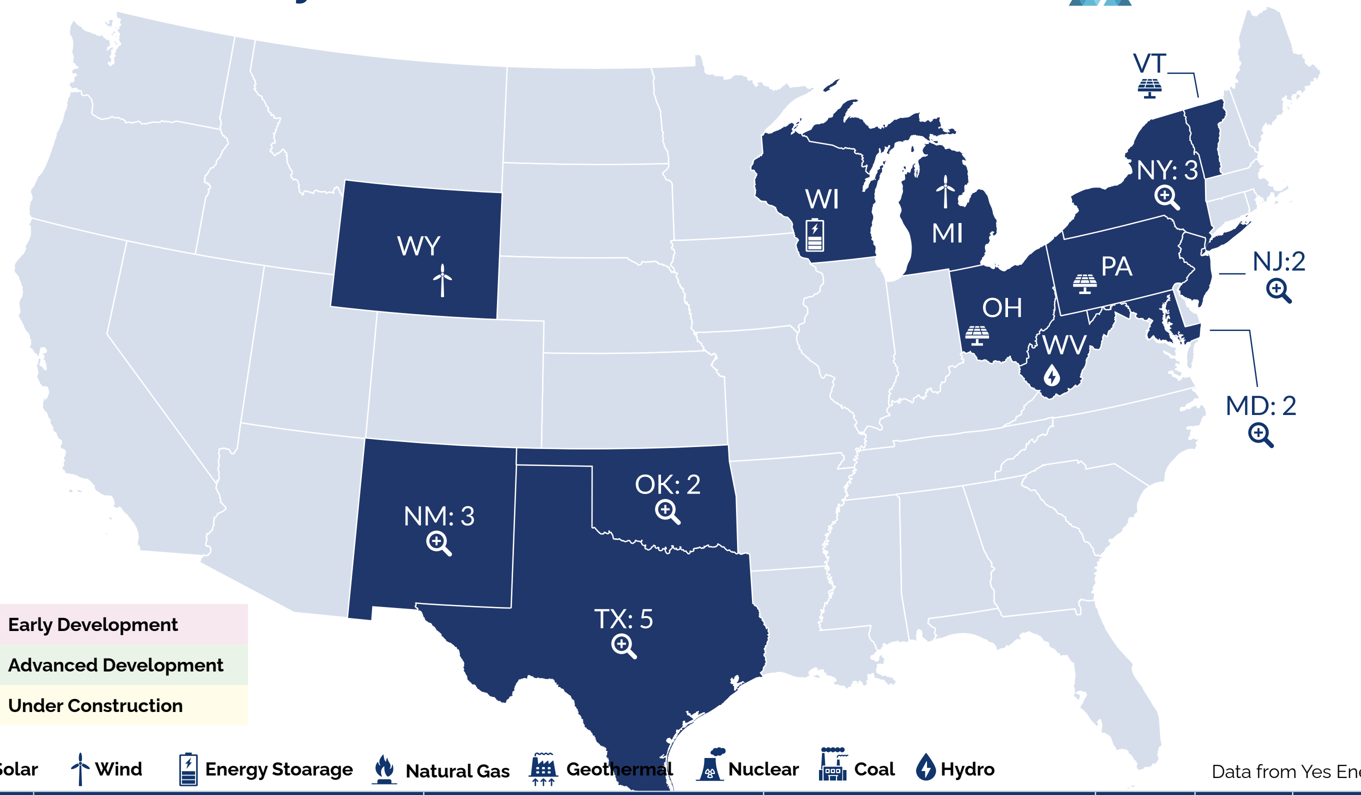
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Harquahala Solar (Phases 4 & 5)	Carlyle Group LP	Copia Power	AZ	250	2028
	Atlas V (Atlas 5) & VI (Atlas 6)	Hanwha Group	Qcells	AZ	237, 120	2028
	Desert Jewel Energy Storage	AES Corp.	AES Clean Energy	CA	200	2029
	Keenesburg Solar	ENGIE SA		CO	7	2026
	Southern Star Solar (CO)	Invenergy, LLC		CO	200	2028
	Southern Star Solar BESS (CO)	Invenergy, LLC		CO	100	2028
	Colquitt Beadles Solar Farm	Inman Solar		GA	6	2027
	Laurens Roche 1 & 2 Solar Farm	Inman Solar		GA	5, 3	2027
	Murray Treadwell IIA & IIB Solar Farm	Inman Solar		GA	6, 2	2027
	Amber Meadow Solar	Nextera Energy, Inc.	Nextera Energy Resources, LLC	GA	200	2028
	Goat Rock Solar	Nextera Energy, Inc.	ESI Energy	GA	430	2032
	Pinewood Solar (GA) BESS	Nextera Energy, Inc.	Nextera Energy Resources, LLC	GA	200	2028
	Rockford Plant 7	ENGIE SA		IL	2	2026
	Harlem School Solar	Blackrock, Inc.	New Energy Equity	IL	4	2026
	MegaPlant Crystal Lake	Blackrock, Inc.	New Energy Equity	IL	2	2026
	Peony Solar Project	Generate Capital		IL	5	2026
	Wild Cat Solar 22	Dimension Renewable Energy	Dimension Energy, LLC	IL	2	2026
	McConnell Road Solar 1	Brookfield Asset Management	Standard Solar	IL	5	2026
	Big Muddy Solar	Arevon Energy		IL	95	2027
	Bayou Teche Solar	ib vogt GmbH	IBV Energy Partners	LA	95	2029
	Kearsarge Sterling	Kearsarge Energy		MA	1	2025
	Callaway Facility	Bloom Energy		MA	4	2026

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

Generation Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

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

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Wheatley Solar	Halo Energy LLC		MD	5	2027
	Berlin Solar	Soltage	Soltage MD DevCo, LLC	MD	18	2028
	Tuscola Wind Energy II (Repower)	Nextera Energy, Inc.	ESI Energy	MI	112	2028
	Gourmet Lane - SLNNJ480 Solar	Prologis		NJ	2	2026
	Bergen Station Uprate	Arclight Capital Partners	Arclight Energy Partners Fund VII, L.P.	NJ	50	2027
	Gonzo Sol Solar Community Solar Garden	Sunshare	CSolPower, LLC	NM	5	2026
	Chaves BESS	Nextera Energy, Inc.	Nextera Energy Resources, LLC	NM	50	2028
	Sagamore BESS	Xcel Energy Inc.	Southwestern Public Service Co.	NM	322	2030
	Barton Solar Farm	EQT Corp.		NY	4	2026
	Cold Springs Solar	Generate Capital		NY	5	2026
	NY Lyons I	Generate Capital		NY	5	2026
	Trenton Solar (OH)	ENGIE SA		OH	10	2027
	Mammoth Plains BESS	Ownership Undisclosed		OK	150	2029
	Panhandle BESS	Nextera Energy, Inc.	Nextera Energy Resources, LLC	OK	70	2028
	Maple Ridge A & B	ENGIE SA		PA	3	2026
	Spinning Spur Repower	Ownership Undisclosed		TX	173	2030
	Palo Duro Energy Storage	Nextera Energy, Inc.	Nextera Energy Resources, LLC	TX	150	2030
	Lariat Wind at Tolk Station	Xcel Energy Inc.	Southwestern Public Service Co.	TX	800	2032
	Plant X BESS	Xcel Energy Inc.	Southwestern Public Service Co.	TX	150	2029
	Sandy Loam at Plant X	Xcel Energy Inc.	Southwestern Public Service Co.	TX	189	2030
	Novus Buck Solar	Novus Energy Development LLC		VT	5	2028
	Cassville BESS	Alliant Energy	Wisconsin Power And Light Co.	WI	25	2028
	Robert C. Byrd Locks & Dam	Conifer Infrastructure Partners LP	Current Hydro	WV	24	2028
	Chalk Bluffs Wind	Black Hills Corp.	Cheyenne Light, Fuel And Power Co.	WY	150	2029

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

Company Briefs

RWE Brings Texas Solar Park Online

RWE Clean Energy last week announced it has brough its Stoneridge solar-plus-storage complex online.

The park, located in Milam County, has 200 MW of capacity with 100 MW of battery storage.

More: *Renewables Now*

Amazon to Build New Data Center Campus in Indiana

Amazon plans to invest an additional $15 billion in Northern Indiana to build 2.4 GW of data centers.

Under an agreement with Northern Indiana Public Service Co., Amazon will pay fees to use existing transmission lines and cover the costs for any new power plants, lines or equipment needed to serve the new campus. The company has invested $31.3 billion in the state since 2010.

The company said the investment is expected to create 1,100 jobs.

More: *Reuters*

SunPower Wraps up $37.5M Deal for Ambia Solar

SunPower said last week that it had finalized the acquisition of Utah-based installation firm Ambia Solar in a $37.5 million deal, a move the company expects will boost fourth-quarter revenue and expand its position in the U.S. residential solar market.

The transaction would create the country's fifth-largest residential solar provider. SunPower said the rapid close of the deal prompted it to raise its revenue estimate for the fourth quarter to $88 million.

SunPower said Ambia brings an operations management team intended to strengthen its direct-to-consumer unit.

More: *Renewables Now*

Federal Briefs

Interior Announces $14.61B in 2025 Energy Revenue

The Department of the Interior's Office of Natural Resources Revenue last week announced the disbursement of $14.61 billion in revenue in fiscal 2025 from energy production.

Disbursement highlights included $5.01 billion to the U.S. Treasury, $4.07 billion to 34 states, $2.98 billion to the Reclamation Fund, $1.05 billion to the Land and Water Conservation Fund, $1 billion to Tribes and individual Indian mineral owners, $350 million to federal agencies and $150 million to the Historic Preservation Fund. New Mexico received $2.76 billion and was one of four states to receive more than $100 million.

More: *Department of the Interior*

TVA Board Nominee Beaman to Appear at Senate Hearing

Lee Beaman, a Nashville businessman, will appear before the Senate Committee on Environment and Public Works on Dec. 3 for a hearing as one of President Donald Trump's nominees to the Tennessee Valley Authority Board of Directors.

Trump nominated Beaman on July 1 along with three others. The president named a fifth nominee, Art Graham of Florida, on July 17. The four nominees other than Beaman appeared at a confirmation hearing Oct. 22 and were affirmed by the committee one week later.

The nominees await a full Senate floor vote before they can be sworn onto the board.

More: *Chattanooga Times Free Press*

EPA Delays Requirements to Cut Methane

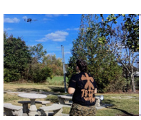
EPA announced last week that it would delay a Biden-era requirement that the oil and gas industry limit emissions of methane.

Under the requirement, oil and gas companies this year were supposed to start reducing the amount of methane they release into the atmosphere. Instead, the Trump administration is giving them until January 2027 and is considering repealing the measure altogether.

Administrator Lee Zeldin said the delay would save oil and gas companies an estimated $750 million over 11 years in compliance costs.

More: *The New York Times*

National/Federal news from our other channels



CISA Releases Drone Security Guides for Infrastructure Operators

ERO Insider

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

State Briefs

ARIZONA

Court Blocks Proposed Utility Rate Pricing Process

The Arizona Court of Appeals last week unanimously blocked the Corporation Commission's expedited process for rate hike requests by utilities.

The judges said the Residential Utility Consumer Office (RUCO) should be given the chance to prove the process for reviewing rate increases adopted by the commission last year is a formal rule, and in turn refused to accept the ACC's argument that what it had done was a mere change in policy. The ruling also means that pending rate hikes cannot use the commission-adopted truncated process until there is a final decision.

Last year, the commission adopted "formula rate plans," allowing for annual adjustments based on a pre-established formula. Commissioners argued this new system allows utilities to recover costs more promptly while passing along any savings or benefits directly to consumers. However, RUCO Director Cynthia Zwick said evidence shows the process could result in higher rates for customers without an opportunity to object.

More: *Arizona Capitol Times*

CALIFORNIA

Sacramento County Approves Solar Farm

The Sacramento County Board of Supervisors has unanimously approved the 200-MW Coyote Creek solar-plus-storage project.

The facility, which will be operated by D.E. Shaw Renewable Investments, will span almost 3,000 acres and will connect to the Sacramento Municipal Utility District. It will also have a 100-MW battery energy storage system.

More: *Renewables Now*

CONNECTICUT

Revolution Wind Continues After BOEM Misses Deadline

The Bureau of Ocean Energy Management missed the deadline to appeal a federal judge's decision ordering work to resume on the Revolution Wind project.

Construction of the of the 704-MW wind farm was allowed to resume Sept. 22 after U.S. District Court Judge Royce Lamberth ruled the federal government lacked justification when it halted work on the project this year. BOEM, which issued the stop-work order, had 60 days to appeal the judge's decision. That deadline passed Nov. 21.

Construction is currently slated to finish in the second half of 2026.

More: *CT Mirror*

OREGON

BPA to Buy Power from OSU Wave Facility

The Bonneville Power Administration has agreed to procure power from the PacWave open ocean wave energy testing facility administered by Oregon State University.

The project spans 2.65 square miles in the Pacific Ocean and is 7 miles off the coast between Newport and Waldport.

Construction was completed this year. Operations are expected to begin in 2026.

More: *Renewables Now*

VIRGINIA

SCC Approves Appalachian Power Rate Increase

The State Corporation Commission has approved a $69 million rate increase for Appalachian Power.

The increase, which will raise the average residential customer bill by $4.36 starting March 1, will allow the company to recover costs associated with renewable energy projects.

More: *Cardinal News*

WEST VIRGINIA

PSC Approves Kanawha County Solar Project

The Public Service Commission last week approved a 90-MW solar project in Kanawha County.

The PSC issued a certificate to allow Mammoth Solar to begin the project. The facility is expected to sit on 446 acres and consist of 193,000 solar photovoltaic modules.

More: *West Virginia MetroNews*

WISCONSIN

PSC Approves Rate Hikes for 3 Utilities

The Public Service Commission has approved rate hikes for three of the state's largest utilities in 2026 and 2027.

The PSC estimates the average Alliant residential customer's monthly electric bill will increase by about $9.57/month in 2026 and $17.45 in 2027 compared to 2025. Average gas bills are expected to rise by $1.08 in 2026 and $1.80 in 2027.

As for Xcel Energy, the residential customer's monthly electric bill will increase by about $13.47/month in 2026 and $24.91 in 2027 compared to 2025. Average gas bills are expected to rise by $7.08 in 2026 and $8.70 in 2027.

Average MGE residential electric bills are projected to increase by about 13 cents/month in 2026 and about $5.44 in 2027 compared to 2025. Average natural gas bills are expected to rise by $1.91 in 2026 and $3.43 in 2027.

More: *Wisconsin Public Radio*