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YES ENERGY

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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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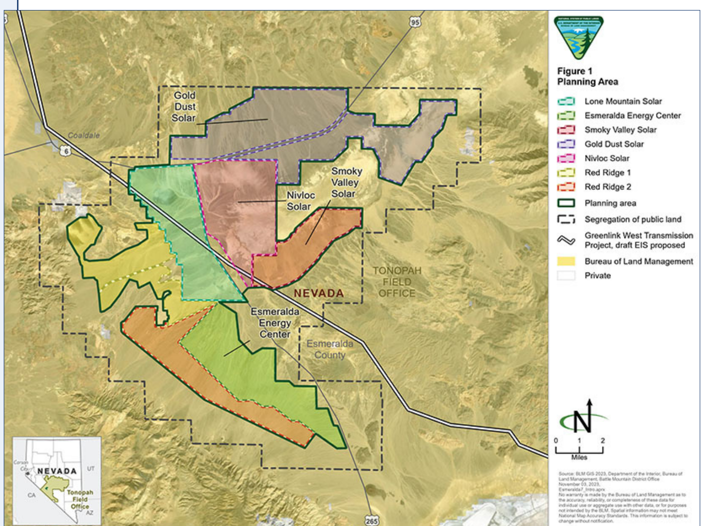
FERC/FEDERAL | PJM

Interior Throws Curveball at Esmeralda Solar Projects, but Denies Cancellation



BLM

The Esmeralda 7 solar energy complex includes several projects that even on their own would be among the largest in the U.S.

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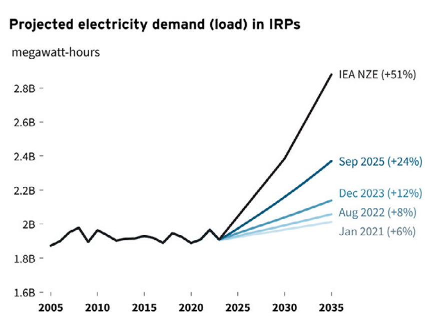

RMI

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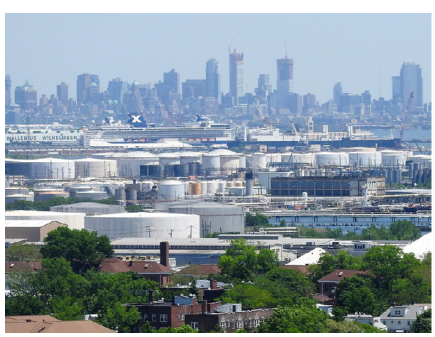

Jim Henderson, CC BY-SA-4.0, via Wikimedia Commons

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RTO Insider
1877 Broadway #606
Boulder, CO 80302

In this week's issue

Trump's Approach to Offshore Wind Threatens Power Grids

Policies also Inject Uncertainty into Energy Investment

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

The antipathy of the Trump administration to the offshore wind industry is well known, and so it has come as little surprise that various federal agencies have been directed to impede the progress of offshore wind developments. This comes at a bad time, just as the multibillion-dollar industry was gearing up, constructing ports and building ships, while training the workforce necessary for the remarkably challenging task of building gigawatts of wind capacity miles offshore.

An Initially Promising Resource: In the early and heady years, the U.S. industry had looked eagerly to Europe's North Sea, where each new offshore project boasted progressively lower costs, and gigawatt-scale projects quickly emerged. That anticipation soon translated to U.S. markets, where billions of dollars were funneled into enabling infrastructure and supply chains, and the Biden administration announced an ambitious target of *30,000 MW of offshore capacity by 2030*. Offshore federal leases for hundreds of thousands of acres along the East Coast were signed, followed by the first steel in the ground, for projects as large as Dominion's $10.9 billion, 2,600-MW Coastal Virginia Offshore Wind Project.

A Radical Change in Direction: With the 2024 presidential elections, however, the winds of fortune shifted rapidly. Within months, the Trump administration announced it was taking a hard line in opposing such projects, and it became clear the future of the industry might be in peril. Most observers were surprised, however, by the intensity of the opposition.

Since taking office, the new administration's Bureau of Ocean Energy Management (BOEM) *has stopped leasing new projects*, rescinding all previously designated offshore wind areas, while *withdrawing nearly $680 million* for ports and manufacturing, and prematurely ending the program of federal tax credits. Perhaps even more critically, the Trump administration took the additional and largely unexpected step of targeting specific projects that already were underway.

The first affected was New York's 810-MW *Empire Wind project*, which was roughly 30% complete when hit by a stop-work

Revolution Wind

order in April which Secretary of the Interior Doug Burgum justified *in a letter to the BOEM* saying the project had been "rushed through" the approval process by the previous administration "without sufficient analysis or consultation among the relevant agencies." The project got back on track a month later, apparently following *an arrangement* for a quid pro quo affecting a long-delayed New York gas pipeline.

That was followed by New England's 700-MW Revolution Wind project, *which was 80% complete* when it got smacked by a stop-work order. The justification in this instance was national security concerns, with Secretary Burgum at one point *citing the possibility* that "people with bad ulterior motives against the United States would launch a swarm drone attack through a wind farm." That order *was quickly overturned* by a U.S. District Court judge, who characterized the order as being "the height of arbitrary and capricious action."

Then last month, the BOEM also filed a lawsuit to revoke a critical permit for the 2,200-MW Maryland Offshore Wind Project, *claiming* it had previously underestimated the effect on search and rescue helicopters and to offshore fisheries.

For its part, the Coastal Virginia Offshore Wind endeavor continues to move forward, reaching 60% completion, with plans to start delivering power by March 2026. It thus far has managed to avoid federal backlash, with a Dominion spokesperson recently and explicitly *citing the historical bipartisan support* for the endeavor.

So, for at least the next several years, we will have two categories of projects: those that manage to squeak through to commissioning, and those that will never make it, despite years of planning, permitting activities and investments in ancillary infrastructure such as ports and ships. Longer-term, the industry may take decades to recover, if it ever does, with investors rightly reluctant to dip their toes into politically fraught waters.

The Costs to Our Power Grids and Investors: Already, the economic casualties are mounting. The latest, announced the second week of October, is *Maersk's cancellation* of an order for a $475 million offshore wind turbine installation ship that is 99% complete and was intended to support New York's Empire Wind effort. There will be many more such investments stranded on the hostile shores of the U.S. offshore wind debacle, totaling in the many billions of dollars, and the implications of these failures likely will spread well beyond a few wind farms. Let's examine the ones that matter the most.

First, there are significant implications for utilities and grid planners in affected areas. Many of these offshore projects have been in the planning stages for years, and the grid operators (as well as other energy investors) have incorporated them into their energy resource and transmission planning processes.

Since these are big projects, their success or failure matters greatly, especially given the difficulty and time required for alternative projects to navigate interconnection queues. One doesn't simply replace these canceled projects with a fleet of gas turbines overnight (one will probably have *to wait many years* to access a new turbine).

Pursuant to the Revolution Wind stop order, grid operator *ISO-NE commented* that it "is expecting this project to come online and it is included in our analyses of near-term and future grid reliability. Delaying the project will increase risks to reliability. … Beyond near-term impacts to reliability in the summer and winter peak periods, delays in the availability of new resources will adversely affect New England's economy and industrial growth."

The grid operator went on to say: "Unpredictable risks and threats to resources — regardless of technology — that have made significant capital investments, secured necessary permits and are close to completion will stifle future investments, increase costs to consumers, and undermine the power grid's reliability and the region's economy now and in the future."

And that gets to the heart of the matter for all energy investors. Unpredictability is the greatest threat to a functioning economy, especially if that uncertainty is politically driven and perceived to be mercurial. Today's energy darling can quickly become tomorrow's pariah.

Offshore wind may be the target of the current administration, but at some future date, those winds may shift again. That is why ExxonMobil CEO Darren Woods commented to *The New York Times* in September that "ever-changing policy, particularly as administrations change, is not good for business."

In September, Martin Durbin, senior vice president of policy for the U.S. Chamber of Commerce, voiced similar sentiments and cautioned against yanking existing project permits, since such a practice "injects significant uncertainty into the infrastructure development process" and could increase the cost of electricity for consumers.

That sentiment was *echoed more recently* by the president of Shell USA, who pointed out in October that the current approach of canceling permitted projects is damaging to business, noting the risk: "However far the pendulum swings one way," she said, "it's likely that it's going to swing just as far the other way."

The Need for a More Consistent Regulatory Environment: The stroke of the regulatory pen is powerful in its ability to stimulate investments at a time when the country's economy desperately needs more energy. But if that same pen cannot be relied upon to exhibit some level of predictability and consistency, then our energy future becomes very uncertain indeed. The infrastructure that supports our ability to generate and move those critically needed electrons relies heavily on a regulatory environment that offers some consistent level of predictability.

Investors must have faith that the hundreds of billions of dollars they place at risk in building out our future energy world will not be arbitrarily affected by a capricious regulatory approach supported by flimsy justifications. The U.S. traditionally has been a far more stable haven for investment than many parts of the world, and we have flourished as a result.

However, if we increasingly turn this effort into a risky and unpredictable political game, the global flow of capital will look for a more hospitable home, and we in the United States will all be the poorer for it. ■

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

Why Chris Wright is So Wrong

5 Charts That Track a 'Leaner, Cheaper and More Secure' Electrotech Future

By K Kaufmann

K Kaufmann

Before he became President Trump's energy secretary, Chris Wright was CEO of Liberty Energy, a natural gas fracking company, and an avid proselytizer for fossil fuels as the foundation of modern lifestyles, prosperity and security in the United States and in emerging nations striving for Western standards of living.

Wright's typical pitch in Liberty *YouTube videos* links global progress, from fighting poverty to lowering infant mortality rates, to two key factors: the spread of human liberty and democratic government and "the surge in plentiful, affordable energy from oil, gas and coal."

Wright's recent efforts to claw back legally obligated federal funding for clean energy projects — many in Democratic-led states — speak volumes about his commitment to liberty and democratic government.

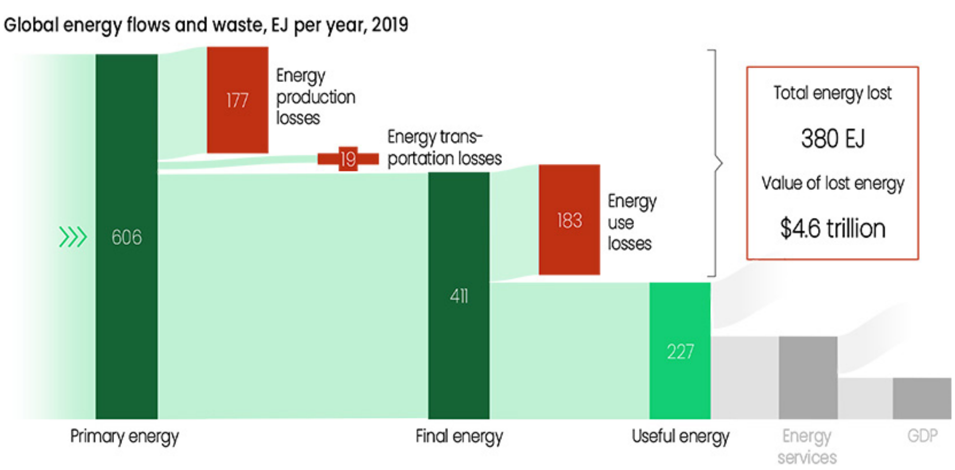
His arguments for fossil fuels are at least historically accurate: The social, technological and economic advances made possible by the Industrial Revolution in the 19th and 20th centuries were powered by fossil fuels. But, as much as Wright discounts it, the world is in the midst of a major energy transition, from petrotech to electrotech, which the vast majority of countries — with the notable exception of the U.S. — are pursuing to promote innovation and economic growth and provide a more efficient, affordable and secure future.

This reframing of the energy transition is laid out in *The Electrotech Revolution*, an extremely detailed, well-documented and provocative report from Ember, a London-based energy think tank.

Rejecting the business-as-usual paradigm of "fossil fuels gradualists" versus "net-zero advocates," co-authors Daan Walter, Sam Butler-Sloss and Kingsmill Bond stake out electrotech as a third way, focused on "exponential energy technologies revolutionizing how we generate, connect and use electrons … such as solar, wind, batteries and digital solutions."

The current fossil energy system is incredibly inefficient

We lose some two thirds of the energy we put into the system



| *Ember using data from RMI*

This electrotech revolution is "driven by physics, economics and geopolitics," they write. "After all, the arc of energy history bends toward solutions that are leaner, cheaper and more secure."

The 112-page report is packed with charts, facts and figures that at every turn demolish Wright's arguments for grounding U.S. energy abundance and dominance — and the welfare of the country's *342 million* citizens — in fossil fuels. It depoliticizes the debate and should be required reading for every federal and state policymaker, regulator, electric industry executive and anyone else concerned or just curious about the future of our electric power system.

Why This Matters

Chris Wright is a smart, well-informed person, but is willfully denying the reality of the electrotech transition to advance the political and financial interests of the Trump administration and the U.S. fossil fuel industry, says columnist K Kaufmann.

Chris Wright is a smart, well-informed person, so I am going to presume he knows everything that is in the Ember report but is willfully ignoring and denying the reality of the electrotech transition to advance the political and financial interests of the Trump administration and the U.S. fossil fuel industry.

A handful of charts from the report show why Wright is so wrong. He and Trump may be able to slow the clean energy transition in the U.S, but the electrotech narrative is undeniable and will win out.

Already, China is leading the transition, and emerging economies are leapfrogging over fossil fuels, the report says. What side of history do we want to be on?

The Inefficiency of Fossil Fuels

The Ember report starts with some eye-opening basics. First, the physics: Fossil fuels are an incredibly inefficient way to produce electricity.

One exajoule, or EJ, is about 278 terawatt-hours of power, so the amount of energy and money we lose burning fossil fuels is simply ridiculous. The figures here, and throughout the report, are global, unless otherwise noted.

Further, the report shows, what most of us really care about is not the primary energy (basic fuels like coal and gas) or final energy (the gasoline and electricity delivered to consumers). Our day-to-day lives depend on useful energy that produces heat and hot water for our homes, plus steel and other goods (energy services) that create economic value (GDP).

Renewable energy and associated clean technologies — like electric vehicles and heat pumps — are two to four times more efficient than fossil fuels for generating electricity, powering our transportation and heating our homes.

At a time of rising electric bills, efficiency and cost savings are top priorities for consumers, businesses and the policy makers and regulators besieged by frustrated and increasingly desperate people, facing critical decisions about which bills to pay first.

The question here is simple: Which side of the laws of physics do we want to be on? We should be planning and building out our electric power system accordingly.

Peaking out

Wright and others often argue that the need for fossil fuels will continue to grow, given the demand for reliable, affordable energy from Europe, China, India and emerging economies.

Wrong again. The Ember report tracks how fossil fuel use has peaked or at least plateaued across various industries worldwide. Pulp and paper and textiles peaked decades ago, while even mining, chemicals and transportation have plateaued. Only construction and non-iron metals, accounting for 6% of industrial demand, are still on a growth curve.

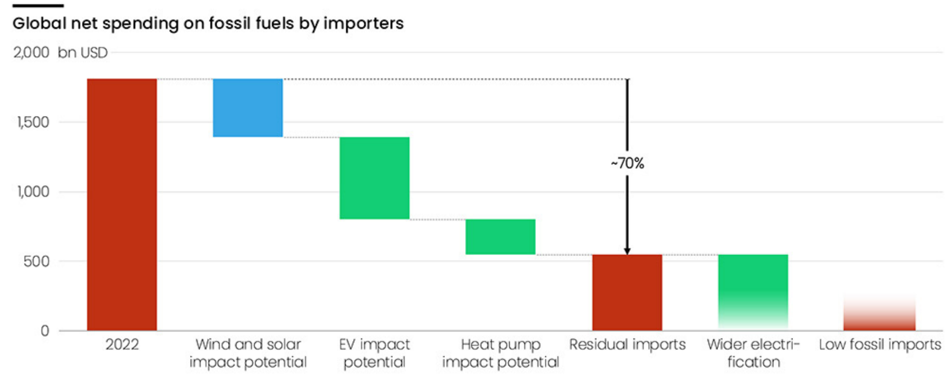
Nearly half of the world is past peak fossil fuel demand for electricity generation, Ember says. China almost singlehandedly has been responsible for any growth in global demand for fossil fuels over the past eight years, but even there, Ember finds evidence that the country is moving toward a plateau.

Slashing Fossil Fuel Imports

At least one point in Wright's argument rings true: Many countries remain dependent on imported fossil fuels — 50, in fact, where imported oil, gas and coal account for 50% or more of the primary fuels they use to produce electricity and gasoline.

Renewables, EVs and heat pumps set you free

Just a few technologies can reduce global energy imports by 70%



Ember using data from IEA WEB and World Bank

At the same time, the report notes, almost every country in the world has sufficient sources of renewable energy — wind, solar, hydro — to meet their existing energy demand, in many cases at least 10 times over. A good three-quarters of Africa is classified as "superabundant," meaning these countries could meet their existing demand 1,000 times over with their renewable resources.

At the same time, the hundreds of billions of dollars spent on importing fossil fuels could be slashed 70% with three existing technologies: renewables in the form of wind and solar, electric vehicles and heat pumps. Wider electrification could shrink fossil fuel imports even further.

While the U.S. is a net exporter of fossil fuels — exporting more than we import — the country still imports more than *8.4 million* barrels of crude oil per day, primarily from Canada. Those imports now come with Trump's 10% tariff; all the more reason to switch from petro- to electrotech.

Emerging Markets Leapfrog

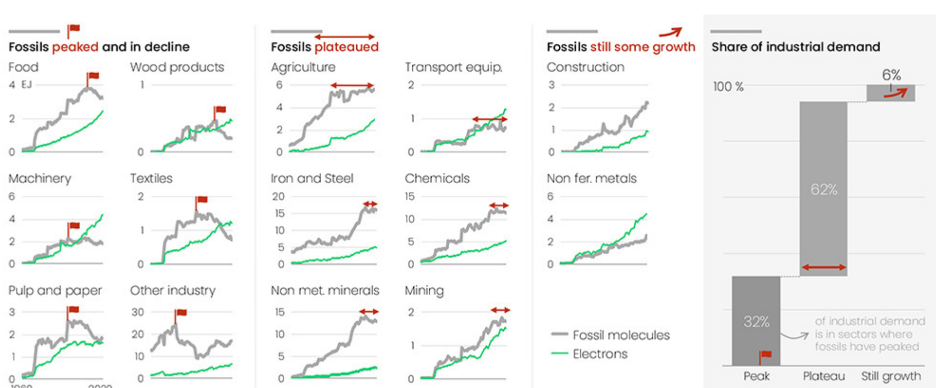
One of Wright's more compelling arguments for fossil fuels centers on energy poverty — the 666 million people around the world who live without electricity, 85% of whom live in Sub-Saharan Africa, according to a *recent report* from the World Bank.

At least, he makes it sound compelling, with fossil-fueled electricity bringing modern, Western lifestyles to emerging economies.

But fossil-fueled power plants require

Industrial peaks everywhere

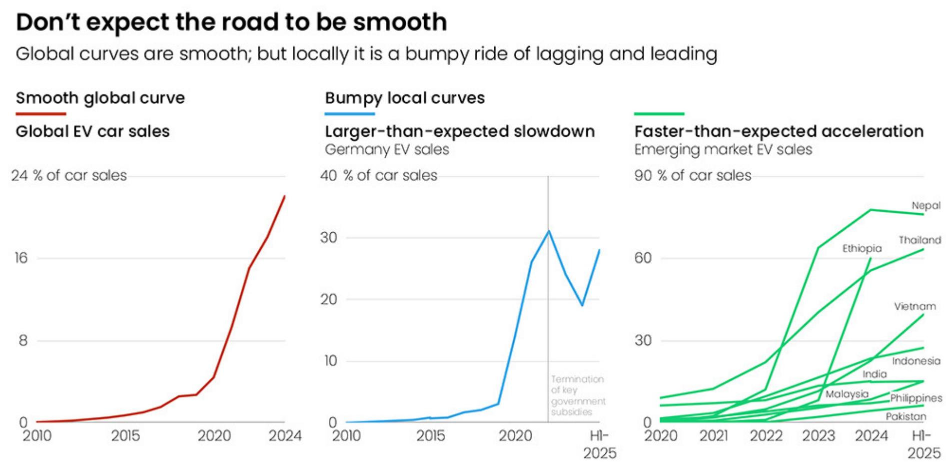
Only 6% of energy demand comes from sectors which still have structural fossil growth



Ember using data from IEA WEB

extensive supply chains and supporting infrastructure — pipelines, transmission systems — which means they may not be the best way to provide power to remote villages in Africa, or anywhere else for that matter. The World Bank notes that "new technologies and business models for decentralized renewable energy (DRE) — such as solar home systems and solar mini grids — offer flexible solutions for these areas."

Which may be why, according to the Ember report, many emerging economies in Latin America, Africa and Southeast Asia are adopting solar and electrifying faster than the U.S., leapfrogging fossil fuels to build their economies on clean energy.



| Ember using data from IEA and Segment Y via New York Times

As noted in the chart above, 63% of emerging economies — from Chile to Vietnam to South Africa — are ahead of the U.S. in solar adoption, while 25% — including Laos, Malaysia and Bangladesh — are ahead in electrification.

Those numbers are, at least in part, being driven by direct cleantech investment from China — more than $100 billion in emerging economies since 2023, Ember says. China dominates global markets in solar, storage and electric vehicles, while the U.S. under Trump is increasingly isolated by high tariffs and falling further behind in clean energy manufacturing and deployment.

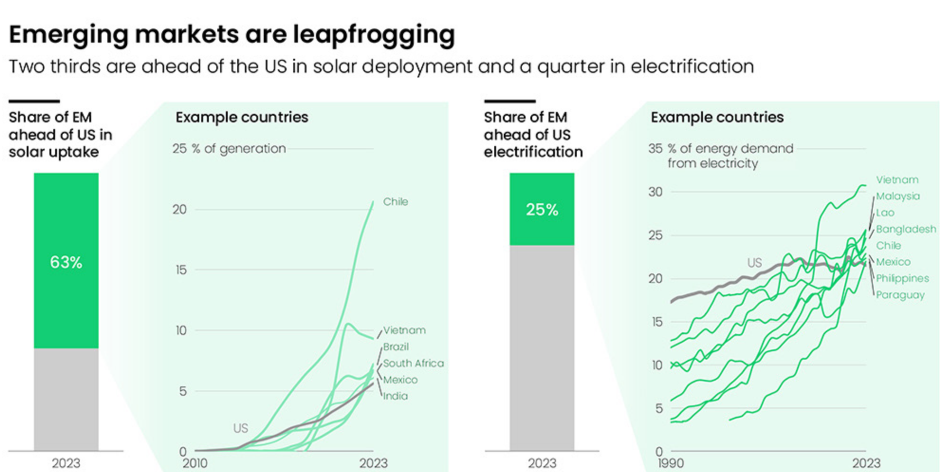
Bumps Ahead

While the physics and economics for electrotech are pretty convincing, Ember knows the real world is rarely as science- and fact-driven as we would like it to be.

The electrotech transition will be uneven across political and economic landscapes, as seen in Ember's analysis of EV sales globally, in Germany and emerging economies. Where markets have been dependent on government subsidies — in Germany and the U.S. — we are going to see some dips and slowdowns, followed by resets and renewed gains.

But such bumps are being offset by faster-than-expected EV adoption in emerging economies, again likely due to China's high-quality but relatively cheap EVs. You know the ground is shifting when 60% or more of new car sales in Nepal and Ethiopia are electric, driving that steep upward curve in global EV sales.

Certainly, the way forward in the U.S. will be even bumpier with Wright and others in the Trump administration putting as many obstacles as possible in the way of renewables and other clean technologies while setting the country on a path to continuing petrotech dependence and ever-rising electric bills.



| Ember using data from IEA

One example: On Oct. 16, Wright *announced* a $1.6 billion loan guarantee to a subsidiary of American Electric Power for transmission upgrades in Indiana, Michigan, Ohio, Oklahoma and West Virginia. According to *figures* from the Energy Information Administration, all five of these states generate two-thirds or more of their electric power from natural gas and coal. Coal makes up 91% of West Virginia's generation mix.

Among 321 Department of Energy grants and other awards Wright *canceled* Oct. 2, 26 were from the Grid Deployment Office.

But one thing neither Trump nor Wright seems to be taking into account — all the DOE employees they have let go are now on the ground, starting new businesses and nonprofits, leading corporate, state and local government efforts to decarbonize their power supplies and pushing electrotech innovation and investment forward. They're ready to ride out the bumps and are not giving up.

Like the Ember report, they know that responding to demand growth in the U.S. and ensuring access to electricity worldwide should not be about politics. Yes, electrotech will cut greenhouse gas emissions, but it is laser-focused on providing the best, cheapest and most dynamic and flexible technology to power our increasingly digital world.

Secretary Wright, come the revolution, what side of history do you want to be on? ■

How ISOs and RTOs Are Addressing Large Load Growth in 2025

By Tim Hough

Data center-fueled demand growth continues to soar while reserve margins continue to shrink. Meanwhile, the timelines for building load versus building generation and transmission are wildly out of sync.

Large loads can stand up in one to two years or less when co-located with generation, while new generation interconnection routinely takes years, and major transmission lines average about a decade from conception to energization.

Because data centers can be developed significantly faster than the generation and transmission required to serve them, NERC has flagged the speed and scale of data center buildout as a near-term reliability challenge. Large loads also pose risks to long-term planning, operations, grid stability, balancing, power quality, forecasting, modeling and grid security.

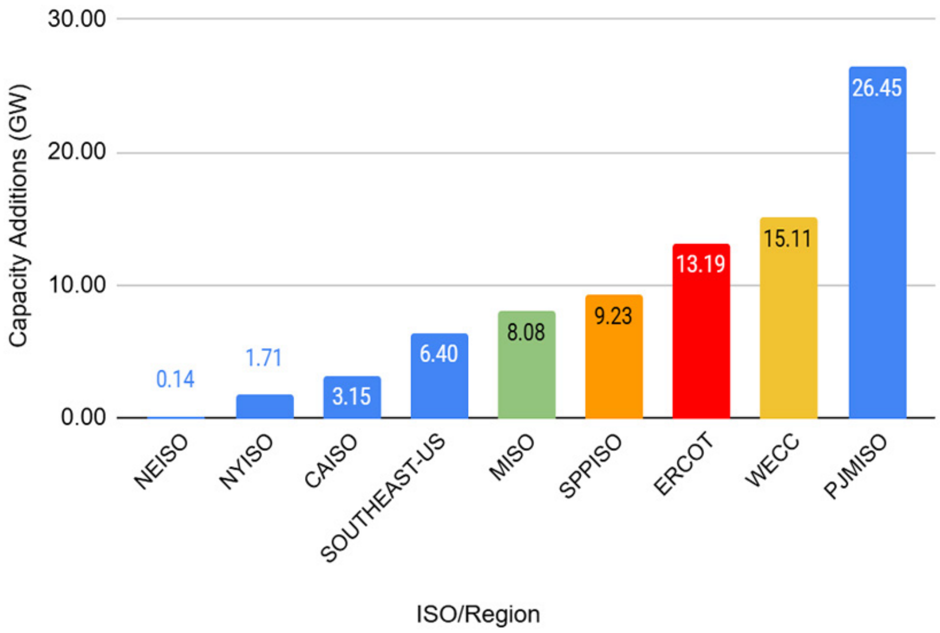
In light of the rising operational and resource adequacy risks, federal agencies, regional organizations, power system operators and utilities are scrambling to analyze and address the impacts related to emerging large loads.

The Department of Energy (DOE) has launched the *Speed to Power* initiative to accelerate the large-scale generation and transmission additions needed to support data center buildout and the AI race. FERC has held technical conferences and written letters around these issues, while NERC and other regional reliability organizations have created task forces and studied the risks of these emerging large loads.

ERCOT, SPP and PJM are paving the way with large load interconnection and participation initiatives.

Just How Big is Large Load Growth?

U.S. data center electricity use rose from 58 TWh in 2014 to 176 TWh in 2023 and is estimated to reach 325-580 TWh by 2028. That translates into roughly 6.7 to 12% of U.S. electricity by 2028 (up from about 4.4% in 2023), according to DOE, underscoring how quickly this new class of demand is growing.



Load center capacity additions from 2020-2025 | *Yes Energy using Yes Energy's Infrastructure Insights data*

Growth is highly geographic, with PJM, the Western Interconnection and ERCOT leading the way due to the major data center hot spots in Virginia, Texas and the Northwest.

Since 2020, PJM has added about 26.5 GW and ERCOT about 13.2 GW of load-center capacity, with more in the queue but significant uncertainty on what actually will be built. SPP also has positioned itself to capture a meaningful slice of data center growth. (*See this* for more information on current and future data center hot spots.)

ERCOT and PJM's load capacity additions are projected to skyrocket in the coming years, but it's still uncertain how much load will get built out.

Characteristics and Risks of Large Loads

Large loads today differ from conventional commercial loads. Large loads can be either large individual consumers or collections of smaller loads that create significant demand and strain on the power grid. Most talked about are data centers, including AI hyperscale data centers, but NERC categorizes large loads as follows:

- Data centers: These include traditional data centers, AI training facilities, AI inference facilities and cryptocurrency mining facilities.
- Industrial load: This includes semiconductor and electronics manufacturing, mining and mineral processing, oil and gas production, metals and heavy manufacturing, and chemical and petrochemical processing.
- Hydrogen production (electrolyzer) facilities.
- Aggregate loads: These are primarily EV charging centers and electrified heating and cooling. Large loads are being built quickly, at large unit sizes, in tight geographic clusters. Many of them, particularly data centers, can shift their computational demand rapidly in response to changing energy pricing, emission intensity and currency pricing.

Compared to traditional electricity load growth, today's large loads are far more location-constrained (e.g., loads need available grid capacity, access to robust fiber optic networks and water access or a suitable climate for cost-effective cooling). They're also far more schedule-driven by corporate road maps and much less interruptible than conventional commercial load.

NERC ranked the risks from large loads:

- high-priority risks: long-term planning for resource adequacy, operations of balancing and reserves, and grid stability.
- medium-priority risks: short- and long-term demand forecasting, real-time coordination, transmission adequacy, frequency stability, cybersecurity, manual load-shed obligations and automatic under-frequency load shed programs.
- low-priority risks: power quality (harmonics, voltage fluctuations) and system restoration following load shedding events.

Consequently, large loads are characterized not only by their megawatt capacity but also by their behaviors that pose grid reliability risks. The consensus defines large load capacity as greater than 75 MW, but voltage level, local system strength and relative size to the area matter as much as raw megawatts. Their behaviors include ramp rates, ride-through behavior, power-electronics content, voltage sensitivity, predictability and internal segmentation.

Existing ISO Large Load Constructs

Before September, ERCOT and NYISO were the only ISOs to have requirements for large load interconnection and preliminary definitions and programs for large loads. In 2022, NERC modified its requirements and measures for facility interconnection studies (FAC-002-4), but it didn't have any megawatt threshold or special process for large loads.

ERCOT established an interim large load interconnection process in 2022 that requires transmission service providers to submit interconnection studies that meet the NERC reliability standard FAC-002-2 requirements for each applicable large load seeking to interconnect within two years. ERCOT formalized and improved this process April 15, after approving Nodal Protocol Revision Request 1234 (NPRR1234) and its accompanying Planning Guide Revision Request 115 (PGRR115).

NPRR1234 updated ERCOT's definition of a large load to be one or more facilities at a single site with an aggregate peak demand greater than 75 MW behind one or more common points of interconnection or service delivery points. NPRR1234 also formalized interconnection and modeling standards for large loads, set standards for loads of more than 25 MW, set requirements for a reactive power study requirement for resource entities adding more than 20 MW of load at a site with existing generation, and established a standardized large load interconnection study. The study is conducted by the transmission service provider with ERCOT review and is described in PGRR115.

In NYISO, interconnection studies are required for loads over 10 MW at under 115 kV, or greater than 80 MW at more than 115 kV. Smaller projects are handled entirely by the applicable transmission operator's interconnection procedures.

Federal Activity

Demand growth outpacing the grid buildout, alongside several executive orders relating to energy dominance and AI, have led DOE to launch the Speed to Power initiative.

The initiative kicked off Sept. 18, with a request for information. It aims to accelerate large-scale additions of generation and transmission so the U.S. "has the power needed to win the global artificial intelligence race" and can continue to serve fast-growing loads.

The RFI seeks details on infrastructure projects that would quickly enable 3 to 20 GW of incremental load, such as new interregional transmission of at least 1,000 MVA, reconductoring of existing lines of at least 500 MVA, restarts of retired thermal plants using existing interconnections and construction of new generation portfolios. MVA measures the apparent power in an AC transmission system, essentially the combined voltage and current capacity a line or transformer can handle. The RFI also asks how DOE should best deploy existing tools and funding programs.

RFI responses are due Nov. 21.

Texas Senate Bill 6, PUCT and ERCOT Action

ERCOT is seeing some of the largest forecast load growth from data centers, with 138 GW of large loads expected on its grid by 2030.

To address the reliability concerns this raises, the Texas state government pushed the envelope with its Senate Bill 6, which passed on June 20. It directs the Public Utility Commission of Texas to adopt largeload interconnection standards for new or expanded large loads greater than 75 MW at a single site in ERCOT, along with study fees ($100,000 minimum initial interconnection fee), site control, uniform financial commitment rules, grid infrastructure cost allocation and a requirement to disclose to utilities any duplicate interconnection requests in Texas.

SB6 also directs the PUCT to develop one mandatory and one voluntary demand management program. The mandatory program requires protocols to curtail large loads of greater than 75 MW that are interconnected after Dec. 31, during firm load shed (with some exceptions for critical load).

The voluntary program, the Large Load Demand Management Service, requires ERCOT to competitively procure demand reductions from loads greater than 75 MW in advance of anticipated emergency conditions.

The PUCT projects for SB 6 are PUCT filings 58317 and 58479.

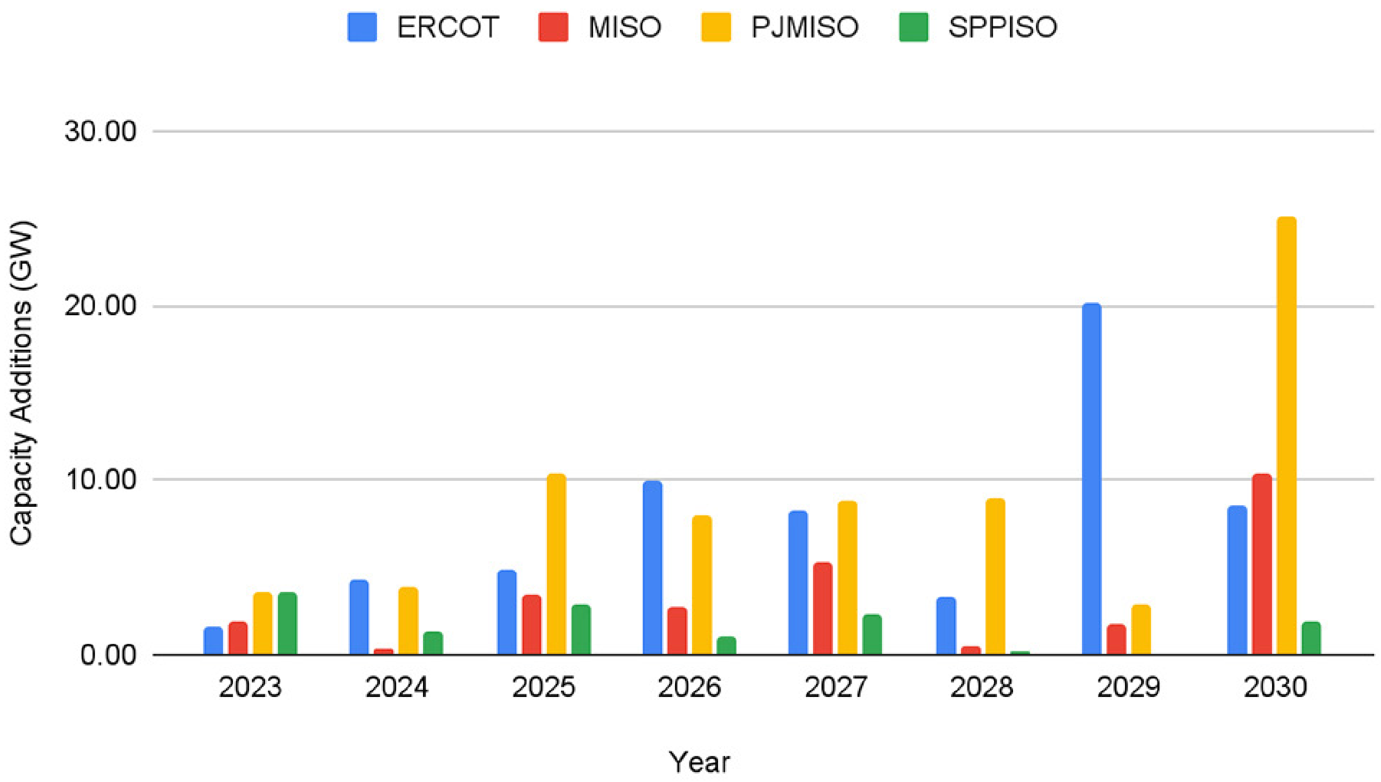
ERCOT has begun related notices and data collection but is prioritizing its Real-Time Co-optimization + Batteries (RTC+B) initiative, which goes live Dec. 5.

SPP's HILLs and CHILLs

SPP recognizes how much uncertainty there is with the load of the future and subsequently has designed a three-phase project that aims to set SPP up for success in all likely electricity load growth scenarios. SPP's three future large load services are:

- a high-impact large load generation interconnection assessment (HILLGA)
- a conditional high-impact large load service (CHILLS)
- a price adaptive load (PAL) service.

The new services aim to reduce interconnection times with a 90-day study-and-approval process for HILLGA and CHILLS, provide flexibility for connection or operation of large loads within system limits and reduce transmission upgrade cost uncertainty. This will offer a



Actual and projected large load capacity additions by ISO | *Yes Energy using Yes Energy's Infrastructure Insights data*

clear path to interconnection agreements while maintaining SPP's reliability standards and transparency in cost allocation.

The first phase of the project began with SPP's revision request *(RR696)*, which was approved by SPP's Board of Directors on Sept. 16. It defines high-impact large loads (HILL) and introduces a generation-supported HILLGA. A HILL is a non-conforming load facility interconnected to the grid that can pose reliability risks.

The HILLGA service offers HILLs two paths for studying and interconnecting associated generation: the common bus path and the local area path.

The common bus path is for HILLs with supporting generation behind the same point of interconnection as the HILL, where generation won't be injected into the grid.

The local area path is a five-year service term for HILL-supporting generation that's within two buses. With the local area path, energy flows on the grid are limited by the HILL's needs and system capacity.

RR696 initially had designs for a third HILLGA path, deliverability area and for a CHILLS. They were removed from RR696 following feedback from stakeholders, who wanted more time to review and revise the deliverability area and CHILLS designs. The CHILLS service was introduced later with *RR720*, which was voted on and failed to pass in SPP's Market Working Group meeting Sept. 23-24. This will delay SPP's timeline, which initially sought to vote on RR720 in the Oct. 14-15 MOPC meeting.

The CHILLS will be a new curtailable transmission service available to HILLs that don't have sufficient transmission capacity or generation to serve all their energy requirements. The portion of a HILL's energy needs that can't be served on a firm basis will be acquired on a conditional basis, so CHILLS is interruptible as needed to maintain reliability.

Conditional HILLs don't need to be supported by generation, but they are required to transition to firm service by the end of the term. In a notable change from its old design in RR696, Conditional HILLs must begin the process of establishing firm service within the first year.

The CHILLS term now is up to seven years long, increased from five years.

SPP also has discussed a price adaptive load service for any load willing to take priceresponsive withdrawal based on realtime pricing. SPP aims to create the revision request by January 2026 and get it approved in April 2026. This timeline may be delayed due to the recent failure to pass RR720 (CHILLS) in the September Market Working Group.

SPP's load-centric interconnection lane compresses the study cycle by pairing load with proximate generation and using conditional service while enduring solutions catch up.

While Texas' SB 6 is the most comprehensive legislative package to date specifically aimed at large loads, SPP is leading the way among ISOs and RTOs with its large load interconnection lanes.

PJM's Critical Issue Fast Path for Large Load Additions

On *Aug. 8, PJM's Board initiated the Critical Issue Fast Path (CIFP)* to develop reliability-based solutions so large loads can interconnect quickly without causing resource inadequacy.

This initiative was motivated by PJM's high capacity prices and looming resource adequacy crisis. PJM's independent market monitor, Monitoring Analytics, found in its *analysis of PJM's 2026/27 capacity auction* that data center load growth was the primary reason for high capacity prices. Nearly 100% of the offered supply was committed in the auction, and data center load drove a $7.2 billion, or 82.1%, increase in capacity market revenues.

PJM's 2025 long-term load forecast showed PJM still may face unmet demand even if everything is built in the generation interconnection queue.

PJM is targeting a FERC filing by December and aims to implement in time for the 2028/29 capacity auction.

The CIFP for large load additions is evaluating criteria for largeload interconnection and coordination with load-serving entities/electric distribution companies (critical for data centers). It's also addressing alignment of large loads connecting to the power grid with the obligation to also provide some generation capacity to contribute to ensuring resource adequacy in the grid, rather than relying on others to do so.

PJM's Stage 1 meeting was held Sept. 15, and the initial proposal centered around three large load interconnection options: BYOG ("bring your own generation") credits for load that arranges new supply, *demand response (DR)* pathways, and a transitional non-capacity backed load (NCBL) service that lets incremental large loads connect quickly but assigns them a lower curtailment priority during emergencies if capacity is short.

After listening to stakeholder feedback, PJM's current proposal has three components:

- **Price responsive demand (PRD) and demand response:** PJM removed the mandatory NCBL concept and instead will use existing DR and modified PRD products to facilitate a process similar to voluntary NCBL. PJM proposes replacing the dynamic retail rate requirements seen in PRD with an energy market offer price. Load could elect not to take on a capacity obligation, requiring it to reduce demand during stressed system conditions rather than pay for capacity.
- **Load forecasting enhancements:** These include allowing state commissions to review and provide feedback on large load adjustments prior to finalizing load forecasts, and add a duplication check in load analysis subcommittee submissions. Each annual large load adjustment submission must inquire and report whether customer interconnection requests are duplicative (inside/outside PJM) and quantify the duplicated megawatts.
- **Expedited Interconnection Track (EIT):** Introduce a 10-month EIT for "sponsored" generation that operates outside and in parallel to the PJM cycle process (the standard generation interconnection process). The EIT would be limited in volume and have strict entry requirements to minimize impact on PJM's cycle process.

Alternative approaches for procuring new resources on a longer-term basis still are in discussion and may be included in the CIFP for large load additions. PJM also mentioned that the manual load shed allocation mechanism needs to be reviewed following the conclusion of this CIFP.

Conclusion

Unprecedented data center-driven demand growth requires unique solutions to address the rising resource adequacy and grid operations risks. There is a timing gap with large loads arriving in months to a few years, while new generation and transmission take far longer.

Besides being large, these loads ramp quickly, are electronics-heavy and location-constrained, and can be price-adaptive, so treating them like conventional commercial growth will miss real reliability and planning risks.

ERCOT, SPP and PJM are leading the charge, creating large load-specific programs to speed up the interconnection and offer unique participation models for large loads and the necessary accompanying supply and transmission capacity.

The path forward includes standardized definitions and studies across ISOs/RTOs, improved participation models and forecasting for high-impact large loads, price-responsive operation, improved time-to-connect, conditional service, curtailment performance and progress to firm capacity. ■

Tim Hough is a market analyst on the market monitoring team at Yes Energy. RTO Insider is a wholly owned subsidiary of Yes Energy.

Interior Throws Curveball at Esmeralda Solar Projects, but Denies Cancellation

7 Nevada Solar Projects Would Connect to Grid Through Greenlink West Transmission Line

By Elaine Goodman

The fate of a 6.2-GW cluster of solar energy projects in western Nevada is uncertain following the Bureau of Land Management's decision to break the group into individual projects for review.

On its National NEPA Register, BLM changed the status of the Esmeralda 7 to "canceled" Oct. 9. The group consists of seven proposed solar projects ranging from 500 MW to 1.5 GW, each with battery storage, on federal land in Esmeralda County.

But the Department of the Interior clarified in an email that "BLM did not cancel the project." Instead, "the proponents and BLM agreed to change their approach" to project review, the department said.

"The projects were initially submitted as a group," Interior said. "The developers will now pursue individual applications for their respective projects. This approach ensures focused, thorough assessments of potential impacts on public lands while supporting responsible energy development."

Interior said the new approach "aligns with the administration's emphasis on improving permitting efficiency and reducing regulatory burdens."

It wasn't clear how the change in the BLM review process might impact project timelines, or whether all the proposed projects will proceed. If completed, several of the individual Esmeralda solar projects would be among the largest in the U.S.

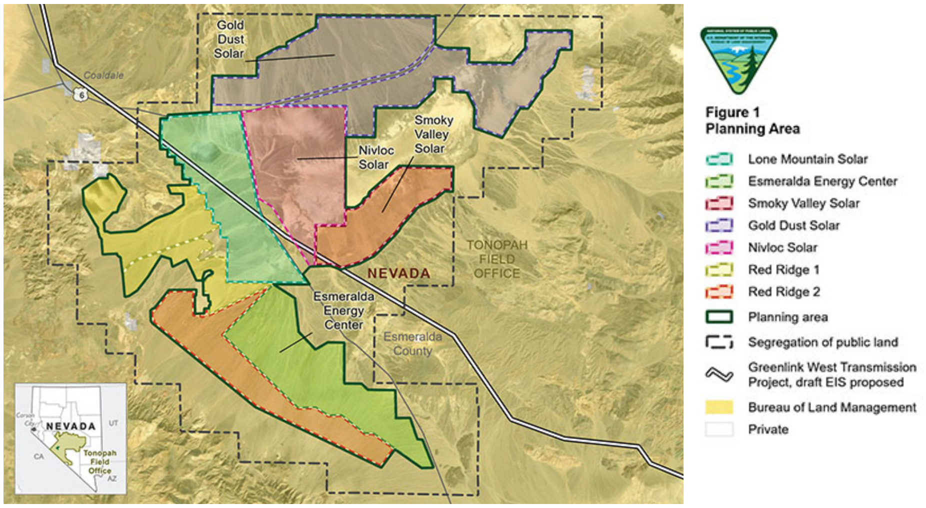
In July 2024, BLM released a draft programmatic *environmental impact statement* and resource management plan amendment for Esmeralda 7. A 90-day public comment period followed. The completed work will still be useful as individual projects move forward, Interior said.

And at least one project developer plans to forge ahead.

NextEra Energy Resources is developing the Esmeralda Energy Center, described in a November 2023 project overview as 1 GW of solar with battery storage.

"We are in the early stages of development and remain committed to pursuing our project's comprehensive environmental analysis," a NextEra Energy spokesperson said in an email. "[We] will continue to engage constructively with the Bureau of Land Management."

Another project is Lone Mountain Solar, 1 GW of solar and 500 MW of battery storage being developed by Leeward Renewable Energy. A timeline on Leeward's website shows a 2027 construction start date with projected completion in 2029. A Leeward spokesperson said the company did not have any information to share regarding the impact of changes to the BLM review process.



Esmeralda 7, a group of solar energy projects proposed in western Nevada, is being broken up into individual projects for BLM review. | *BLM*

Why This Matters

The Esmeralda 7 solar energy complex includes several projects that even on their own would be among the largest in the U.S.

The other projects are:

- Gold Dust Solar, 1.5 GW of solar and 1 GW of storage developed by Arevia Power;
- Nivloc Solar, 500 MW of solar with battery storage by Invenergy;
- Smoky Valley Solar, 1 GW of solar with battery storage by ConnectGen; and
- Red Ridge 1 and 2, each 600 MW of solar with battery storage by 335ES 8me.

Developers had planned to interconnect their projects through Greenlink West, NV Energy's 350-mile, 525-kV transmission line under construction across the west side of the state.

Each solar project would include a tie line connecting to Greenlink West's Esmeralda substation.

One goal of Greenlink West and Greenlink North, a transmission line planned across northern Nevada, is to open more of the state to renewable resource development. When completed, the two Greenlink lines along with the existing One Nevada Line will form a transmission triangle around the state.

Energy development within transmission corridors such as Greenlink West is expected to drive additional local and regional renewable energy development, BLM said in its draft environmental report. ■

DOE Lays out Road Map to Bring Nuclear Fusion to Market

Public-private Framework to Accelerate, Strengthen R&D Efforts

By John Cropley

A new Department of Energy strategy seeks to accelerate progress toward the long-sought, long-elusive goal of commercially viable nuclear fusion power.

The "*Fusion Science and Technology Roadmap*" seeks to coordinate and align public and private efforts and is part of the Trump administration's broader energy dominance initiative.

The road map identifies research, materials and technology gaps that must be bridged before a fusion pilot plant can be built. It sets out three primary ways to accomplish this that boil down to build, innovate and grow: construction of critical infrastructure; innovation through advanced research, high-performance computing and artificial intelligence; and growth of a fusion ecosystem incorporating public-private partnerships, regional manufacturing hubs and workforce development.

The road map identifies six core challenge areas to be tracked with milestones and metrics: structural materials; plasma-facing components and plasma-material interactions; confinement approaches; the fuel cycle; blankets; and fusion plant engineering and system integration.

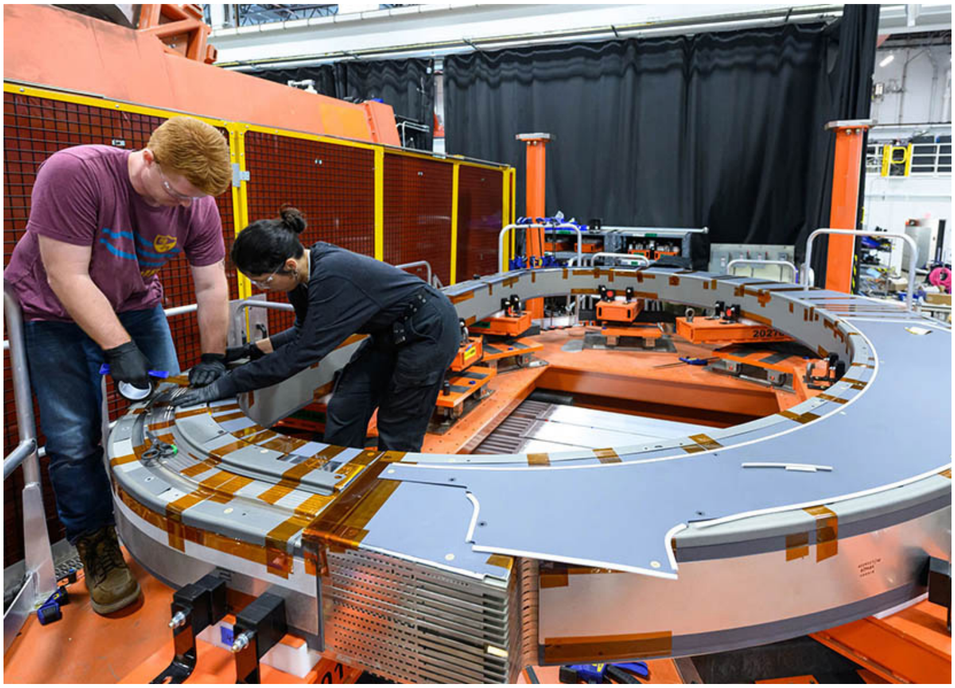
The goal is to build the public infrastructure needed to support the scale-up of private-sector fusion generation in the 2030s.

DOE *formally announced* the road map Oct. 16, after it was unveiled earlier in the week during events centered on fusion energy in D.C.

Energy Secretary Chris Wright *spoke enthusiastically* about fusion and the new road map at the Special Competitive

Why This Matters

The roadmap is an attempt to speed progress toward the tantalizing goal of commercial nuclear fusion.



Technicians work on the nuclear fusion system Commonwealth Fusion Systems is developing. | *Commonwealth Fusion Systems*

Studies Project's *AI+ Fusion Summit* in D.C. on Oct. 14.

"We're going to get the fusion ball moving," he said. "I think we will see more progress in the next five or 10 years, much more progress than in all of the history before on fusion. We're finally going to see the reality of fusion come, first in the electricity grid, ultimately in industrial process heat to make things, and hopefully we can rapidly scale that up."

The new road map is aligned closely with and builds off the Fusion Energy Sciences Advisory Committee *Long-Range Plan*, issued in 2020. The road map combines the earlier plan's science drivers with a revamped Fusion Energy Science public program in DOE's Office of Science in hopes of bringing to fruition what has been a very lengthy effort.

As skeptics like to point out, fusion research and development efforts have not yet lived up to the hope and hype surrounding them. A running joke is that the world has been 20 years away from perfecting commercial fusion for 50 years.

Wright addressed this at the Oct. 14 summit: "I worked on it 40 years ago. It isn't that we've gotten nowhere in 40 years. It's just a hard problem to replicate the sun on Earth. … We've made progress over the last 40 years, and we're about there."

What is different now, Wright said, is that artificial intelligence presents the need for large amounts of new electrical generation capacity, such as through fusion, and a tool to help develop fusion generation; fusion R&D is attracting private capital, which is less patient than public funding; and the U.S. wants to lead the world on fusion, rather than see the leadership role go to China, which is making massive investments to do just that.

"What China doesn't have is the commercial sector we have," Wright said. "We have billions of dollars of private money in different companies, backing different strategies, with different biases. We're going to naturally get a broader choice."

DOE's network of national laboratories can complement these private-sector R&D efforts in key areas such as developing the materials needed to withstand the intense environment of a fusion reactor, he said.

Wright said one of the obstacles facing this initiative is budget cuts. While he agrees with President Donald Trump's push to reduce spending, he said cuts should be targeted at subsidies for existing technologies, not directed broad stroke at everything in DOE's budget.

"And I've had the political challenge to sell 'not everything,'" he said. "In fact, there's things we spend money on today that we should spend more on, not less on, even though we have a big budget deficit, and basic fundamental science is absolutely one of those."

The U.S. needs to come closer to matching China's investment of state funds in AI, Wright said: "My God, the upside of it is just — it's hard to imagine. So we need to continue to bring confidence and private money into it, but we need to bring more government money into it."

DOE in its road map notes the billions of dollars of private-sector investment pouring into fusion.

The Fusion Industry Association *reported in July* that the 53 fusion companies it surveyed had raised a combined $9.77 billion in funding, a fivefold increase over their total four years earlier. More than $2.5 billion of that was secured just in the past year, it added. The great majority of the capital has been private, with not even $800 million in public finding reported.

But 83% of companies said they still consider investment a major challenge, and their estimates of funds needed to bring their first pilot plants online were a combined $77 billion.

They remain optimistic, however: 84% expect to deliver power to the grid before 2040 and 53% by 2035.

Twenty-nine of the 53 companies surveyed for the association's 2025 "*Global Fusion Industry Report*" are based in the U.S., and all three of the companies reporting more than $1 billion in funds raised are based here as well.

Commonwealth Fusion Systems of Massachusetts has claimed a leadership position in the pack, with *nearly $3 billion raised* as of late August, or approximately 30% of the total reported by private fusion companies worldwide. It has announced plans to build what it promotes as the world's *first grid-scale fusion plant* in Virginia in partnership with Dominion Energy, and has announced power purchase agreements with *Google* and *Eni* that would account for more than half of the facility's planned 400-MW nameplate capacity.

DOE previously supported Commonwealth's work through funding streams including *INFUSE*, the *Milestone-Based Fusion Development Program* and *ARPA-E*. ■

NOPR Would Get Pipelines to Offer More Information for Grid Operators

By James Downing

FERC has issued an official notice that proposes new standards for business practices that are meant to improve coordination between the electric and gas industries involved in interstate natural gas pipelines.

The proposal would incorporate the latest changes to Version 4.0 of the Standards for Business Practices of Interstate Natural Gas Pipelines adopted by the Wholesale Gas Quadrant of the North American Energy Standards Board (NAESB).

"Such coordination is essential to maintaining reliability for both the natural gas pipeline network system and the bulk electric system, especially during periods when both systems have coincident peak requirements," FERC said in the NOPR. (The notice of proposed rulemaking is part of the FERC process required before issuance of a final rule.)

Better electric and natural gas coordination has been a priority for decades with FERC, NAESB and other entities making iterative changes as the interdependent, but much differently regulated industries, continue to evolve.

"I wouldn't frame it quite like it's never going to be done," FERC Chair David Rosner said at the post-meeting press conference. "I would frame it more like — on Tuesday, we're having our annual reliability conference, and if you look back at the arc of our reliability work, it's constantly evolving. And so one thing that's important to me is that we work with our expert staff and NERC and with our industry partners to make sure that as the world changes, as these sectors evolve, that we're doing things that are smart and that are durable, and that make sense, and that solve problems ideally, before they become problems."

| *Shutterstock*

The changes come out of a forum NAESB held at the request of former FERC Chair Rich Glick and NERC CEO Jim Robb "to identify actions that will improve the reliability of the natural gas infrastructure system as necessary to support the bulk electric system and to address recurring challenges stemming from natural gas-electric infrastructure interdependency." NAESB set up its Gas-Electric Harmonization Forum to tackle those issues, issuing a final report in July 2023. (See *NAESB Forum Chairs Push for Gas Reliability Organization*.)

Other aspects come from FERC and NERC's Winter Storm Elliott report, which included some recommendations on coordination that NAESB took up. The changes include one revised standard and two new ones.

The revised standard creates a central location on pipeline informational websites where they can post publicly available data such as scheduled quantity information. Now, pipelines will have a new information category: "Gas Electric Coordination," which can help ISO/RTOs and other parties assess the data during extreme weather or emergency events.

The first new standard facilitates the posting of applicable scheduled quantity information for power plants that are directly connected to the pipeline as part of the "Gas Electric Coordination" category.

The second new standard supports the inclusion of geographic information of affected areas, locations and/or pipeline facilities by a transportation service provider when issuing a critical notice.

Commissioner Judy Chang filed a concurrence, lauding the work NAESB has done to improve gas-electric coordination with the new standards but urging continued work to improve communication between the sectors and to address remaining issues.

The Bottom Line

The NOPR is meant to improve information sharing practices at pipelines to improve electric-gas coordination, especially during extreme weather. Commissioner Chang concurred, making some additional recommendations and seeking more from the industry as gas-electric coordination is an ever-evolving issue.

"The NAESB standards proposed here exemplify the type of brick-by-brick incremental improvements needed to address pressing gas-electric coordination challenges," Chang wrote. "However, these proposed standards alone may not be enough to fully address the ongoing challenges."

More information sharing will improve situational awareness for grid operators and generators, which will help when the systems are stressed. It might make sense to include information about gas scheduled for generators not directly connected to the pipeline system, she suggested.

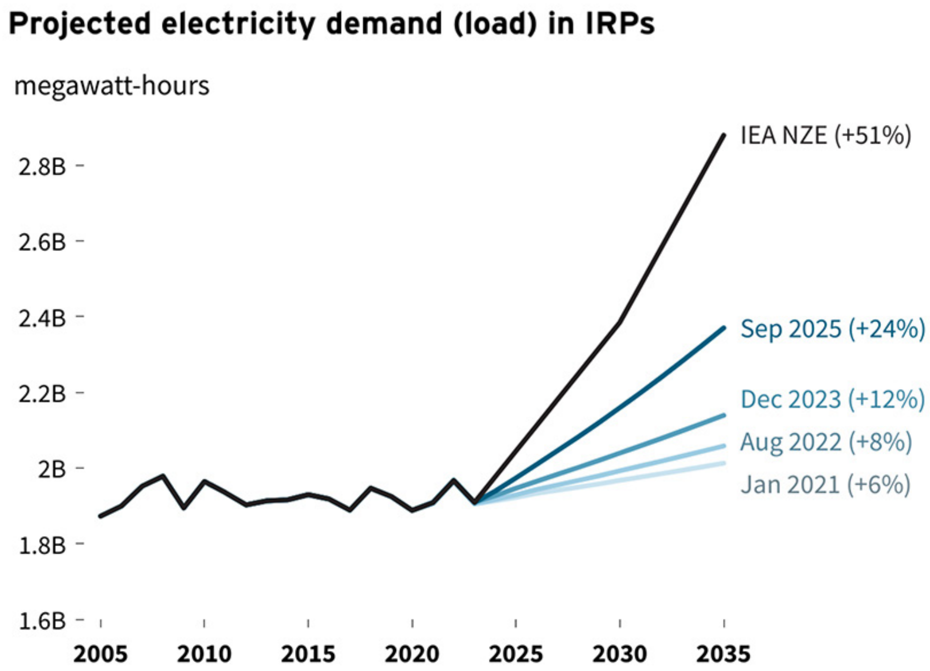
"I further encourage continued collaboration between pipelines, suppliers, natural gas marketers and owners of upstream gas gathering systems to update pipeline operators and ultimately downstream gas users and electricity system operators of changes in system conditions, such as wellhead freezes, that could affect natural gas users and consumers," Chang said.

She asked commenters in the NOPR process to suggest other changes that could improve coordination. ■

Sharper Load Growth in Utility Integrated Resource Plans

RMI Analysis Overlays the Increase with Uncertainties, Challenges in Meeting It

By John Cropley



As of September, U.S. utility integrated resource plans forecasted 24% load growth by 2035, compared with 12% in 2023 and 6% in 2021. | *RMI*

U.S. utilities continue to ratchet up load growth forecasts in their integrated resource plans.

As of September, the IRPs are projecting demand will be 24% higher in 2035 than in 2023, RMI reported Oct. 15. This compares with 12% in December 2023 and 6% in January 2021.

The third-quarter "*State of Utility Planning*" report is the latest in a series by RMI and combines data from 130 IRPs. As RMI notes in its preface, IRPs are not a clear picture of the future, but they do provide a snapshot of trends, goals and strategies to meet those goals.

The third-quarter report is the first that reflects the impact of the One Big Beautiful Bill Act, with its phaseout of tax credits for wind and solar generation, which recently have been the largest source of new U.S. generation by nameplate capacity.

Other factors gaining prominence in the third quarter included delayed fossil retirements, uncertainty in planning, inability to bring new resources online quickly and difficulties in buying electricity from neighboring utilities.

Trends continuing from previous quarterly reports include changes in resource adequacy rules, particularly in MISO, as well as the expectation that new large loads will present demands that cannot easily be met.

These factors are set against a background of considerable uncertainty over factors such as resource costs, market rules, EPA regulations, other federal policies, frequency of extreme weather events, state policies and the load-growth forecasts themselves. The forecasts are demonstrably imprecise, and some observers maintain that top-end projections are unrealistically large.

Every IRP reviewed for RMI's third-quarter report increased the load forecast over previous projections but also showed a wide range of uncertainty about the size of that increase. Both the quantity and hourly profiles of these new loads differ from historical trends.

The difficulty of resource planning amid all this is a common point of discussion for utilities, RMI said, along with the need to devise new ways to meet future needs.

RMI noted that since it began tracking IRPs, load projections have increased in all nine quarters and cumulative emissions projections have increased for seven consecutive quarters.

It also pointed out that emissions reductions are lagging in utility projections: The companies examined have targets of 63% emissions reductions by 2035 from a 2005 baseline, but their IRPs would lead to only a 53% reduction.

The IRPs include 259 GW of wind and solar additions through 2035, 103 GW of natural gas additions and 74 GW of coal retirements. This is 2.4% more wind and solar than was planned as of the end of 2023 but 106% more natural gas.

RMI acknowledged the challenges facing electric utilities as they try to balance regulations, costs for customers, profits for investors and climate impact.

But the clean energy advocacy nonprofit also said delayed fossil retirements and new gas generation are the default choice in most IRPs, which instead should *incorporate alternatives* such as energy efficiency, virtual power plants, grid enhancing technologies and clean repowering.

These alternatives — along with policy and regulatory support — would help utilities hold down costs as they transition to a zero-carbon future, RMI concludes.

The report combines historical data from RMI's *Utility Transition Hub* with IRP data manually collected by EQ Research. The 130 IRPs reviewed would cover approximately 48% of U.S. electricity deliveries. ■

Why This Matters

The update shows the demand growth U.S. utilities expect to see and the challenges they expect to encounter in meeting it.

LBNL Study Examines Drivers Behind Higher Power Prices in Some States

By James Downing

The Lawrence Berkeley National Laboratory released a *paper* recently examining why some states have seen retail power prices rise faster than inflation. The listed reasons include distribution investments, extreme weather and wildfire, natural gas prices and state renewable targets.

"Factors influencing recent trends in retail electricity prices in the United States" includes an *article* in *The Electricity Journal*. It found that states in the Northeast and on the West Coast saw some of the biggest price increases from 2019 to 2024 but noted the national averages were in line with inflation.

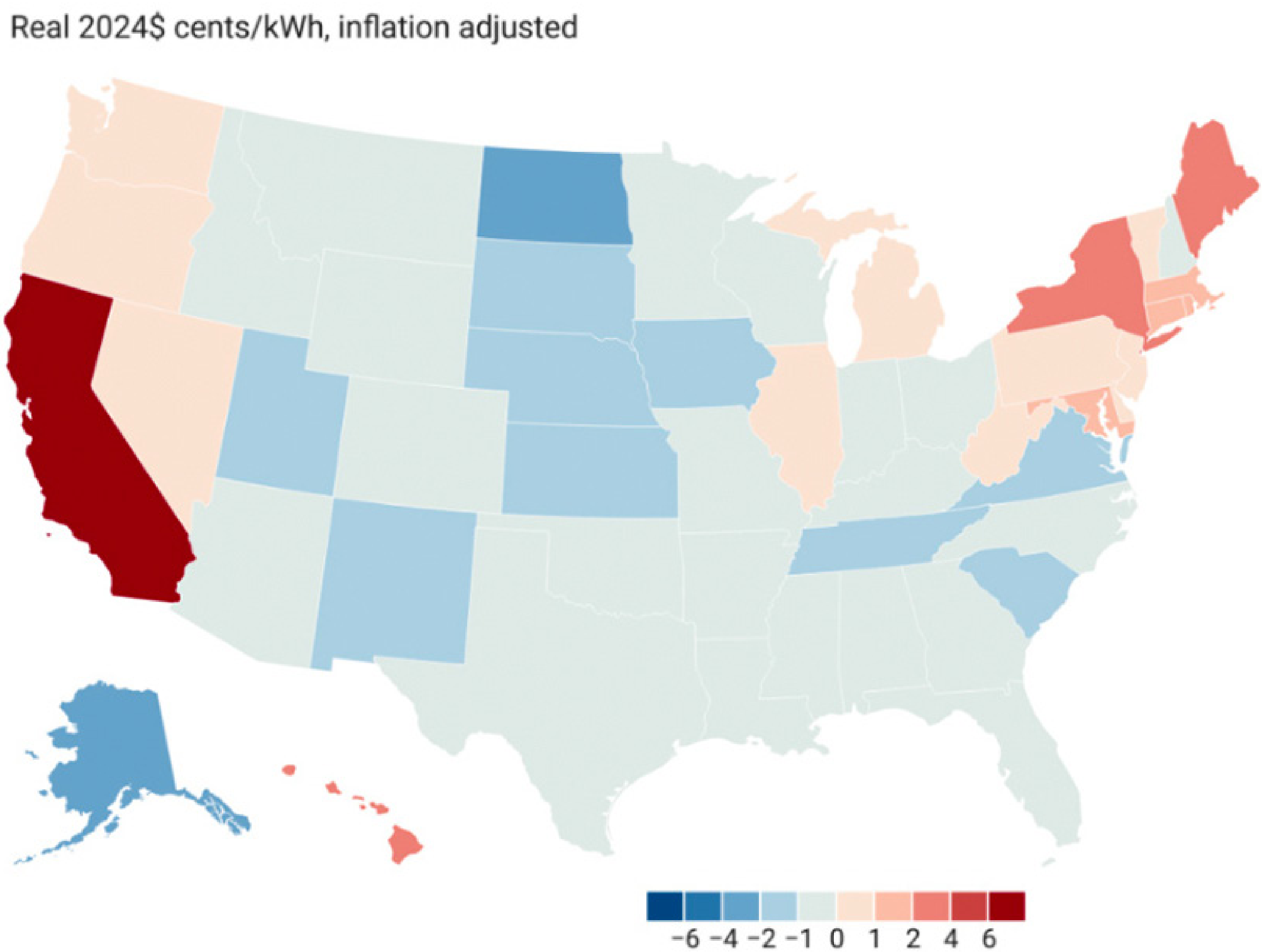
Why This Matters

The study uses statistics to examine what is driving retail power prices across the entire country, finding in general that load growth from 2019 to 2024 led to lower average prices.

In nominal terms, prices rose 23% between 2019 and 2024. Controlling for inflation, they were flat outside of a bump in 2022 related to the Ukraine-Russia war's effect on natural gas prices. The national average masks a big difference in state average prices that range from 8 cents/kWh in North Dakota to more than 27 cents/kWh in California.

"Examining recent trends in inflation-adjusted prices, 31 states saw real price declines from 2019 to 2024, while 17 states experienced increases," the article said. "States on the West Coast and in the Northeast were most affected by rising prices — especially California, where average retail prices increased by 6.2 cents/kWh in real 2024 dollars."

States with the greatest price decreases typically exhibited increasing customer



A map produced for a presentation alongside the report showing how average retail prices changed by state from 2019 to 2024. | *Lawrence Berkeley National Lab and Brattle Group* loads over that period, which misses the recent run-up in PJM capacity prices in the 2025/2026 auctions that are affecting customer bills now, according to a presentation accompanying the study.

PJM's Independent Market Monitor found that new data center load contributed to the largest chunk of the capacity price increase (alongside some market design parameters), and most PJM states saw retail prices jump from 10 to 15% when the new delivery year started.

Rising demand from data centers, manufacturing and other sources has been cited as creating a risk of higher prices due to their purported impact on wholesale markets, higher retail prices or cost allocation policies that might favor large commercial and industrial customers in the name of economic development. But the study found that load growth from 2019 to 2024 tended to reduce retail prices.

"In the 2019-2024 time frame, the regression suggests that a 10% increase in load was associated with a 0.6 (±0.1) cent/kWh reduction in prices, on average," the article said.

That aligns with the understanding that a primary driver for utility spending has been refurbishing existing transmission and distribution infrastructure in recent years. Spreading those costs over a larger base cuts average prices, but the study noted that negative load-price relationship was seen in average prices and lost when focused on residential prices.

"Load growth over this historical period was led by commercial customers, and cost allocation practices have tended to benefit those large, non-residential customers," the article said.

The study focuses on average prices across customer classes, but it noted that residential prices generally are higher than commercial and industrial prices and have risen more than those classes in recent years.

Investor-owned utilities have seen prices rise faster than public power, but the article noted that in California it is largely due to differences in wildfire risk and related costs.

"States with the greatest price increases typically exhibited shrinking customer loads — partially linked to growth in net metered behind-the-meter solar — and had renewables portfolio standards (RPS) in concert with relatively costly incremental renewable energy supplies," the article said.

Net energy metering offers participants bill savings, but utilities must invest more in their distribution systems and recover fewer fixed costs from customers on NEM programs. The study found a 5% increase in net-metered, behind-the-meter solar led to an average price increase of 1.1 cents/kWh.

Utility-scale wind and solar development that happened outside of RPS might have led to lower retail prices in recent years, though the impact was not statistically significant, the article said. It added that RPS targets are likely to increase prices if they lead to renewables the market would not have delivered. Three-quarters of utility-scale wind and solar growth from 2019 to 2024 happened outside of RPS mandates.

Another major driver of higher prices is extreme weather, which impacts two of the states that have seen prices rise the most in recent years – Maine and California. Central Maine Power's storm recovery cost rider rose from 0.1 cents/kWh in late 2020 to 1.8 cents/kWh in 2024.

"Between 2019 and 2023, California's three large IOUs were authorized to include $27 billion in wildfire-related costs in retail prices," the article said. "By June 2024, wildfire-related costs constituted an average of 17 % of total IOU revenue requirements, up from 1.7 % in 2019 and, if directly translated into one-year cost impacts, equivalent to a 4 cent/kWh increase."

On average, the states with the highest wildfire risks have seen power prices rise by 1.1 cents/kWh, the article said. ■

Nonprofits Warn of Potential TVA Privatization Ahead of Board Hearings

By Amanda Durish Cook

Environmental and social justice organizations have expressed concerns the Tennessee Valley Authority could be headed toward privatization with a slate of board candidates assembled by the Trump administration.

The nonprofit group Appalachian Voices is urging senators to question the four TVA board nominees' intentions as to the sale of TVA's publicly owned assets to private companies. The Senate Environment and Public Works Committee has a *hearing* Oct. 22 to consider board nominees. The nonprofit said it is concerned the potential new board composition could "sell TVA to the highest bidder."

The Senate committee is due to consider:

- Mitch Graves of Memphis, Tenn., a health care CEO who has served as a board member for Memphis Light, Gas & Water and maintains investments in *multiple* energy companies.
- Jeff Hagood of Knoxville, Tenn., an *attorney* who has experience in criminal defense, injury litigation and representing university sports coaches and student athletes.
- Randy Jones; Guntersville, Ala., an insurance executive who also serves on the Guntersville Electric Board.
- Arthur Graham of Jacksonville, Fla., a member of the Florida Public Service Commission through Jan. 1, 2026, and a former city council member. If installed on the board, Graham would be the first TVA board member to live outside of states that contain TVA service territory.

Trump's fifth nominee to the TVA board, businessman Lee Beaman of Nashville, Tenn., is not included on the agenda for the upcoming hearing and is expected to be considered later. Beaman is the former owner of a network of Nashville-area car dealerships and is a prominent Republican fundraiser.


TVA's Norris Dam | *TVA*

For months, the nine-seat TVA Board of Directors has lacked a quorum. It *contains* just three members: Chair Bill Renick, Bobby Klein and Wade White. TVA requires five board members to establish a quorum and make decisions.

The Trump administration fired Biden-era appointees Michelle Moore, Joe Ritch and Beth Geer in the span from late April to mid-June.

The Trump administration previously proposed selling off parts of the TVA. During Trump's first term, his team twice floated the idea to privatize some of TVA's assets in budget requests for fiscals 2019 and 2020. At the time, the White House Office of Management and Budget reasoned that the private sector is better positioned to own transmission assets and that government ownership causes "sub-optimal investment decisions" and "unnecessary risk to taxpayers."

Congress rejected both attempts.

So far in his second term, Trump hasn't proposed the sale of TVA assets in a formal budget proposal. However, Appalachian Voices said it suspects the administration will pursue sales directly through the TVA board and CEO.

Appalachian Voices, along with Energy Alabama, the Sierra Club, Third Act Tennessee, Sunrise Nashville and multiple union organizations, hosted two virtual rallies Oct. 16 to urge the public to oppose TVA privatization.

In a press release, Appalachian Voices said it was apprehensive that the slate of candidates could sell off TVA's assets. The group called the roster "largely unqualified" and said TVA needs "expertise on its board of directors, not pro-privatization auctioneers."

"We urge senators to use this hearing and other conversations with the TVA board nominees to ensure they intend to keep TVA in the people's hands, and to reject any nominees who don't prioritize the interests of the people of the Tennessee Valley over billionaires and corporations," Bri Knisley, director of public power campaigns at Appalachian Voices, said in a statement.

Why This Matters

Appalachian Voices and other nonprofits are warning that confirmation of Trump's five nominees to the Tennessee Valley Board of Directors could spell a TVA selloff down the road.

The Revolving Door Project, an executive branch appointee watchdog, *said* the Trump administration seeks to "stack the TVA governing board with a slate of nominees seemingly poised to do the bidding of his billionaire allies and corporate donors alike." The group added that the Trump has "reinvigorated concerns over TVA's privatization."

TVA didn't outright answer *RTO Insider*'s request for comment on possible privatization. Instead, the federally owned utility provided a fact sheet noting that it has fully self-financed through revenue from its electric sales since 1999 and does not contribute to taxpayer expenses.

"In fact, every year, TVA is a source of cash to the federal government, paying annual dividend-like return payments on the original investment in the power system," TVA said. "The TVA model also results in savings every year for taxpayers across the country. TVA provides services that would otherwise be the responsibility of other federal agencies, such as river system management, flood control, navigation, land management and other related regional, multistate functions — without taking any annual appropriated funding."

TVA said its management of reservoirs and recreation areas "serve as a driver for nearly $12 billion in total economic activity and more than 130,500 jobs." It also said it "prevents more than $300 million in flood loss each year." ■

9-GW Power Gap Looms over Greater Northwest, Co-op Warns

By Henrik Nilsson

Why This Matters

PNGC Power's warning is the latest to highlight the many challenges aging infrastructure and data centers bring to the energy industry.

The Northwest faces a "pretty scary" situation, with a new study showing a potential 9-GW capacity shortfall by 2030, increased energy prices and building constraints, the Pacific Northwest Generating Cooperative's (PNGC Power) CEO said Oct. 15.

Jessica Matlock, CEO at PNGC Power, told the Northwest Power and Conservation Council that a *recent study* by Energy and Environmental Economics (E3) predicts that accelerated load growth and aging power plant retirements will create a resource gap starting at about 1.3 GW in 2026 and expanding to almost 9 GW by 2030.

"That's approximately the load of the state of Oregon," Matlock said.

As is the case nationwide, data centers are the primary drivers behind the expected load growth. PNGC members already have 15 data centers seeking connection within their service territories, Matlock said.

"And we wonder, is that really going to materialize? Well, they actually already came in and bought all the property and got the permits from the county, and they're breaking ground. So, it's actually happening now," Matlock said.

Matlock added that the data centers are the "mega ones. These are the big ones that you all hear the names of: Amazon, Meta."

PNGC consists of 25 electric cooperatives spread across seven Western states. PNGC operates as a Joint Operating Entity, allowing the utilities to pool resources and share risks. PNGC also is Bonneville Power Administration's largest preference customer, according to the co-op's website.

"Traditionally, we get all our power from Bonneville, but it's been clear that Bonneville is pretty tapped out of hydropower, and so the region is looking at this huge deficit," Matlock said.

BPA's power rate schedule consists of multiple categories of primary rates for federal energy sales, including Priority Firm Tier 1 rate, which represents most of BPA's power sales. Tier 2 rates are for energy a utility obtains from the agency in addition to its contractual right to power at Tier 1 rates, according to BPA's *website*.

The issue now, Matlock said, is BPA's Tier 1 is fully allocated, and the agency must compete for power on the market "against tech companies and other IOUs … that have deeper pockets in Bonneville."

In July, BPA published new rates in its final record of decision for the BP-26 rate period covering the 2026/28 interval. Under the new rates, customers' power rates will increase by about 8 to 9% over the next three years, while transmission rates will jump by an average of nearly 20%. (See *BPA Customers to See Increased Power, Transmission Rates*.)

"It's getting pretty scary," Matlock said. "So, the price of Tier 2 power for Bonneville is going to go up, including Tier 1 power."

BPA spokesperson Maryam Habibi noted that BPA has created a new methodology for post-2028 under new provider-of-choice contracts.

"We would set the Tier 1 amounts each customer is able to purchase under a calculation outlined in that new provider of choice policy through a process next year," Habibi said. "We don't yet know if we would need to augment our resources for Tier 1 or Tier 2."

Meanwhile, generator resources in active development account for 3,000 MW of new capacity, 850 MW of which are coal-to-gas conversions and 350 MW are hydro upgrades, Matlock noted.

"The others are wind, solar, potentially biomass, a couple other different resources," she added. "That is not going to get us to where we need to get to."

Some states, like Washington and Oregon, have strict decarbonization policies, making it difficult to meet the new resource adequacy requirements many utilities will be subject to under the two day-ahead markets emerging in the West: SPP's Markets+ and CAISO's Extended Day-Ahead Market.

"For those states that are really confined to what they can develop — because you cannot develop natural gas in some of those — how are they going to meet these? We're not sure," Matlock said.

To meet the resource adequacy requirements with just renewable power "would require huge amounts of land."

"We are developing solar and battery," Matlock said. "That's because we get additional capacity. We are continuing to talk to solar companies to develop that to shift to our Washington members. But the biggest problem for us to get this solar power to these members is the transmission system is too congested."

She noted that PNGC is building a natural gas plant in northern Idaho from which it will ship natural gas to members in Washington state "to help keep the lights on."

PNGC is exploring building transmission itself with the help of federal grants aimed at connecting data centers to transmission and then partnering with BPA on the buildout. The agency has paused certain transmission planning processes to clear the interconnection queue. (See *BPA Transmission Pause Questioned During Workshop*.)

"If we can't get transmission to move solar, wind, natural gas, geothermal across the region to supply power to cities and towns, we are going to have a significant problem," Matlock said.

Habibi said BPA does not build its own resources, but she noted that the agency has launched initiatives, such as the Grid Access Transformation project, which are "designed to improve access and streamline our processes for connecting resources." She added that the new power contracts "add flexibility for customers to add new, non-federal resources. That flexibility does not exist today." ■

VPPs Suffer Setbacks in Calif. Legislative Session

Governor Signs OSW Funding, Data Center and Fusion Research Bills

By Elaine Goodman

California Gov. Gavin Newsom on Oct. 10 signed a package of bills to help Los Angeles recover from the January wildfires. | *California Governor's Office*

The 2025 California legislative session ended in disappointment for virtual power plant proponents, as Gov. Gavin Newsom vetoed several VPP-related bills and lawmakers didn't approve new funding for an existing program.

Assembly Bill 740, AB 44 and Senate Bill 541 were vetoed before the governor's Oct. 13 bill-signing deadline. Bills sent to Newsom that aren't signed or vetoed become law without the governor's signature.

Edson Perez, California lead at Advanced Energy United, called the vetoes of the VPP bills "missed opportunities to save billions in energy costs by leveraging technologies all around us in our homes, garages and on our roofs."

"This policy whiplash undermines confidence across the sector, discourages the deployment of cost-saving technologies and drives away investments," Perez said in a statement.

Virtual power plants are collections of distributed energy resources, such as solar panels, batteries, electric vehicles or smart devices, that can be called upon to boost the grid when needed.

AB 740 would have directed the California Energy Commission to work with CAISO and the California Public Utilities Commission to explore how virtual power plants could help meet statewide load shift goals and what opportunities are available for VPPs to qualify for resource adequacy. Perez said the bill aimed to make VPPs a core part of California's energy portfolio rather than solely an emergency resource.

In vetoing the bill, Newsom cited budget constraints.

"While I support efforts to realize the potential of these energy resources and others, this bill results in costs to the CEC's primary operating fund, which is currently facing an ongoing structural deficit, thereby exacerbating the fund's structural imbalance," Newsom said in his veto message.

Newsom also vetoed *SB 541*, which would have required the CEC to work with CAISO and the CPUC to analyze the cost effectiveness of certain load-shifting strategies, estimate each retail electricity supplier's load-shifting potential, and report the amount of load shifting that each retail supplier achieved in the previous year.

Newsom called SB 541 "largely redundant and, in some cases, disruptive of existing and planned efforts" by the agencies to maximize the potential of load-management strategies.

AB 44, which the governor vetoed, would have directed the CEC to devise methodologies that load-serving entities could use to modify their demand forecasts in response to measures such as VPPs.

The governor said the bill does not align with the CPUC's resource adequacy framework.

"As a result, the requirements of this bill would not improve electric grid reliability planning and could create uncertainty around energy resource planning and procurement processes," Newsom said in his veto message.

Another disappointment for VPP advocates was lawmakers' decision to not provide additional funding for the CEC's demand side grid support (DSGS) program. As part of the program, battery owners agree to make their stored energy available to the grid during energy emergency alerts or when day-ahead prices go over $200/MWh. They then are compensated based on the power they shared with the grid. (See *Budget Cuts Threaten Calif. VPP Program*.)

In an Oct. 1 *statement*, the CEC said DSGS had about $64 million remaining. CEC expects to have enough money to pay out incentives from the 2025 program season and will look for ways to continue the program in 2026.

Advanced Energy United hopes the state

Why This Matters

Virtual power plants will likely continue to be an issue for California lawmakers when they reconvene on Jan. 5, 2026.

will "course correct" on VPPs as soon as possible, Perez said, starting with more funding for DSGS in early 2026 to keep the program going.

Offshore Wind Funding

In contrast to the setbacks for VPP bills, lawmakers made progress on other energy-related issues.

As previously reported, the legislature passed and Newsom signed *AB 825*, known as the Pathways bill. The bill will allow CAISO to transition the governance of its markets to an independent "regional organization." (See *Newsom Signs Calif. Pathways Bill into Law*.)

Newsom also signed *SB 254*, a law that will create a "transmission accelerator" to develop low-cost public financing programs for certain transmission projects. The legislation also establishes an $18 billion "continuation account" for the state's wildfire fund to cover investor-owned utilities' wildfire liabilities. (See *Calif. Lawmakers Pass Bill to Accelerate Transmission Development*.)

Offshore wind advocates were pleased that lawmakers passed and Newsom signed *SB 105*, a budget bill that includes $228.2 million for offshore wind. The funding is the first installment out of $475 million earmarked for offshore wind in Proposition 4, the $10 billion climate bond measure that California voters approved in 2024.

Of the $228.2 million in SB 105, the CEC has already distributed $42 million in grants to improve port facilities for floating offshore wind projects. (See *CEC Approves 5 Offshore Wind Projects at California Ports*.)

Offshore Wind California, an industry coalition, called the funding "another important proof point of California's progress and commitment to move forward on offshore wind."

"California is demonstrating its continued determination to be a clean energy leader, despite the federal headwinds we're facing this year," the group said in a statement.

Other legislation that Newsom signed includes a data center-related bill. *SB 57* requires the CPUC to send a report to the legislature on the extent to which utility costs associated with new loads from data centers are shifted to other customers.

And *SB 80*, which Newsom signed, creates the Fusion Research and Development Innovation Initiative to distribute $5 million for fusion energy research and development. The goal is to deliver a fusion energy pilot project in the state by the 2040s.

Surplus Interconnection Bill Vetoed

Newsom vetoed other bills, including *AB 1408*, which would have required CAISO to consider surplus interconnection service in its long-term transmission planning. It also would have required utilities to evaluate and consider surplus interconnection options in their integrated resource plans. Proponents said unused interconnection capacity creates an opportunity to add renewable energy resources or battery storage at or near fossil plants.

In his veto message, Newsom pointed to the "highly technical structure of processes" used by the CEC, CPUC and CAISO for grid planning.

"This bill risks constraining energy resource procurement and interconnection options, likely increasing customer electric costs and undermining electric grid reliability," he wrote.

A bill aimed at requiring more accountability from the CPUC didn't even make it to Newsom's desk. *AB 13* also would have asked the governor and Senate to consider geographic diversity when selecting CPUC members to address a lack of Southern California representation. (See *Calif. Lawmakers Seek More Accountability from CPUC*.)

The bill died in committee. ■

Uncertain VPP Program in California Sets Capacity Record

By David Krause

A virtual power plant program with an indeterminate future set a record in 2025 for the capacity the plant contributed to California's electricity grid.

The California Energy Commission's VPP program has seen a big increase in available capacity since the end of the 2024 season, CEC analyst Brian Vollbrecht said at an Oct. 15 workshop.

About 38,000 customers participated in the program in 2024, providing about 288 MW to the grid. In August, the program's capacity exceeded 400 MW.

The VPP program is part of the demand side grid support (DSGS) program, which is within the state's strategic energy reliability reserve. The reserve provides electricity supply and load reduction and has a goal of 7,000 MW by 2030.

The DSGS program has four options. Most of the workshop focused on VPP Option 3, which rewards battery owners who provide capacity to the grid during energy emergency alerts or when market day-ahead prices go above $200/MWh. Option 3 participants provide this capacity during extreme weather and grid events from May to October.

No residential resources with durations beyond two hours participated in the VPP, and nearly half of the VPP capacity was in the Pacific Gas and Electric region, with the rest in the Southern California Edison region and the San Diego Gas & Electric region.

At the workshop, Robert Castaneda, board president of the Low-Income Oversight Board of the California Public Utilities Commission, asked if the CEC had a socio-demographic breakdown of VPP participants.

Vollbrecht said that this type of data was not a part of the analysis "this time around."

Why This Matters

California's grid operators have relied on power supply tools like virtual power plants to meet increasing demand in the state.

"But if you have questions about that, feel free to follow up with us," Vollbrecht said.

An Unknown Future

Although the VPP program reached a new high in 2025, California lawmakers decided not to provide additional funding for the DSGS program. (See *VPPs Suffer Setbacks in Calif. Legislative Session*.)

DSGS's funding has experienced "various shifts since its inception due to state fiscal pressures," Deana Carrillo, director of the CEC's Reliability, Renewable Energy and Decarbonization Incentives Division, said at the workshop.

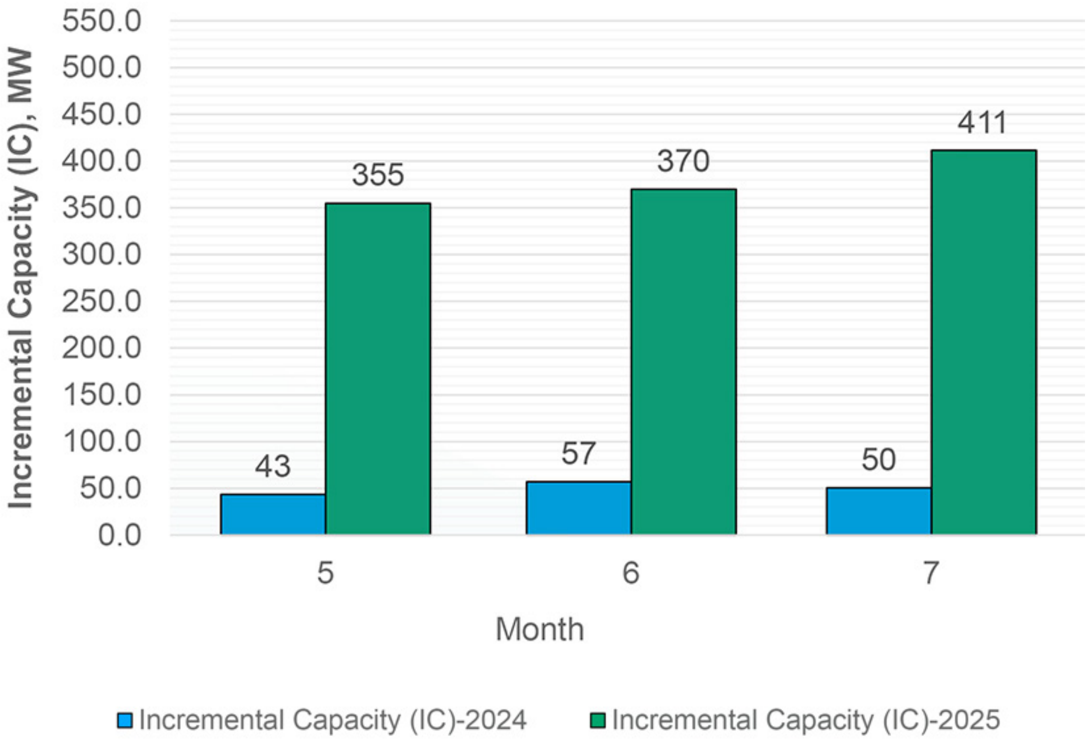
"And I recognize that this is challenging for private industry that is participating in the program, because while we're attesting approaches to grow demand and incorporating the lessons learned, there's also a need for consistency and a glide path to inform your business models," she said.

There are, however, "active, ongoing discussions about the program's budget," Carrillo added.

"Staff is having conversations with leadership to identify stable funding beyond 2026 and continue the program's growth into test concepts," she said.

In total, DSGS's budget is $109.5 million, with about $30 million remaining at the end of 2025, CEC program manager Payam Narvand said at the workshop.

CEC staff proposes continuing the DSGS program into the 2026 program season. Any changes to the program will be informed by a public engagement process and approved at a CEC business meeting, Narvand added. ■

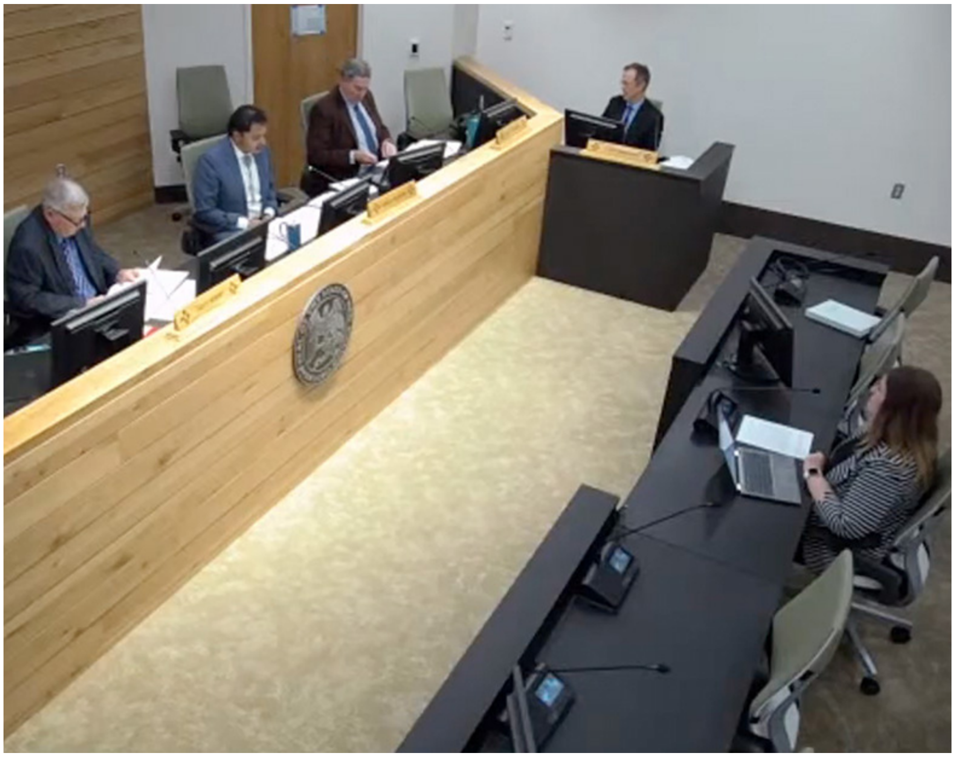


Monthly average incremental capacities (2024 and 2025) | *CEC*

PNM Accounting Request Revives EDAM vs. Markets+ Debate

New Mexico Regulators Find that Spending to Join EDAM is 'Reasonable'

By Elaine Goodman


The New Mexico Public Regulation Commission meeting on Oct. 16 | *New Mexico PRC*

State regulators approved an accounting order for Public Service Company of New Mexico's participation in CAISO's Extended Day-Ahead Market, in a case that rekindled the debate over which day-ahead market PNM should choose.

The New Mexico Public Regulation Commission voted 3-0 on Oct. 16 to approve the order, which allows PNM to create a regulatory asset for its EDAM costs. That means PNM will track its EDAM costs separately from other expenses and later seek to recover the costs in a rate case.

PNM estimated its EDAM implementation costs will be $11.1 million in capital costs, $3.1 million in one-time operations and maintenance expenses, and $1.4 million to $1.6 million a year in ongoing costs from 2028 to 2030.

The company announced its decision to join EDAM in November 2024 and plans to start participating in fall 2027. (See *PNM Picks CAISO's EDAM* and *PNM Signs Agreement to Join CAISO's EDAM*.)

PNM's request for an accounting order sparked filings from those who supported the request and those who believe the company should have chosen SPP's Markets+ instead of EDAM.

"To me, it's kind of nuts that this case became a referendum on market choice, or parties tried to make it so," Commissioner Pat O'Connell said before the vote.

O'Connell said keeping EDAM expenses in a separate account would make it easier to later inspect the costs and compare them to benefits of market participation.

The commission found that it is "reasonable" for PNM to "expend costs in joining EDAM." The prudency of the expenditures will be evaluated during a future rate case, when the amount of spending is known.

The commission didn't authorize PNM to include carrying charges in its regulatory asset, saying that doing so would constitute "ratemaking treatment in advance."

Parties have until Nov. 17 to file a motion for rehearing.

Regional Market Proceeding

In a Sept. 11 filing, Tri-State Generation and Transmission Association asked the commission to deny PNM's application. Tri-State pointed to PNM's 2018 request for an accounting order for the costs of joining CAISO's Western Energy Imbalance Market. In that case, the commission granted the order without making a reasonableness determination.

Commission Chair Gabriel Aguilera said PNM's new request was unique because it followed a lengthy commission proceeding that examined the potential benefits of regional market participation by the state's investor-owned utilities. The proceeding included a series of workshops where studies on projected benefits of market participation were presented. Utilities and stakeholders weighed in with numerous filings.

Utilities were not required to obtain commission approval for their day-ahead market participation. But the commission issued a set of guiding principles in November 2024 intended to guide the utilities' market decisions. (See *NM PRC Issues 'Guiding Principles' for Electricity Market Participation*.)

"PNM's decision to join EDAM is not a decision that was made quickly or without thorough consideration," the commission said in its order. Rather, it is a result of "the time, effort and investigation put in by multiple entities that participated in [the docket]."

Why This Matters

Although Western utilities are settling into separate footprints for participation in CAISO's EDAM or SPP's Markets+, antagonism between the two sides remains.

EDAM Decision Questioned

In its filing, PNM pointed to a Brattle Group study that projected benefits from joining EDAM would be $20 million a year vs. $8 million a year for joining Markets+. PNM said the difference in benefits was a key factor in its decision to choose EDAM.

Tri-State argued that the $20 million and $8 million figures are based on PNM and El Paso Electric participating in the same market. But El Paso Electric has announced its intention to participate in Markets+, while PNM is going with EDAM. (See *El Paso Electric to Join SPP's Markets+ in 2028*.)

Tri-State said the benefit difference "is not actually driven by the adjusted production cost but is instead driven by different expectations of congestion revenues and bilateral trading revenue." A presentation on the findings in August 2024 did not say "with any level of certainty how likely these benefits are to materialize," Tri-State added.

Tri-State said that key considerations from the commission's guiding principles — including greenhouse gas tracking, fair governance, seams management and market design — favor PNM's participation in Markets+ or SPP's RTO rather than EDAM.

PNM countered by saying its choice of EDAM was a discretionary action.

"PNM's decision to join the EDAM is not properly before the commission in this proceeding; it is a decision PNM made 10 months ago and informed the commission of at that time," PNM wrote in a reply to Tri-State.

Western Resource Advocates (WRA) also weighed in on PNM's accounting order request, saying PNM had acknowledged the commission's guiding principles for choosing a day-ahead market and presented "a reliable cost-benefit analysis study performed by the Brattle Group."

WRA recommended the commission approve PNM's request for an accounting order with the addition of certain reporting requirements before and after it enters EDAM.

The commission's order directs PNM to provide updates on any "substantive changes to the market" and to file quarterly reports after its EDAM participation begins. The reports will detail cost savings to customers, transmission availability and use, renewable resource curtailment, resource planning impacts and market performance during extreme weather, among other issues.

After two years, PNM must file the reports annually. ■

FERC Sides with San Francisco in PG&E Cost Allocation Dispute

By Henrik Nilsson

FERC sided with San Francisco in the city's dispute with PG&E over cost allocation provisions in a wholesale distribution contract, finding PG&E improperly required the city to bear the cost of system upgrades instead of allocating costs among all beneficiaries.

The Oct. 16 order affirms an administrative law judge's previous finding and directs PG&E to revise its wholesale distribution tariff within 60 days and issue refunds to its wholesale distribution customers (*ER20-2878*).

FERC found that under the company's cost allocation provisions, the City and County of San Francisco would shoulder the entire cost of upgrades to distribution systems and facilities even though the utility's retail customers also benefited from those improvements. That scenario results in a violation of FERC's cost causation principles.

PG&E spokesperson Jennifer Robison told *RTO Insider* that the utility appreciates FERC's "thoughtful review of our filing."

"Our goal in updating PG&E's wholesale distribution tariff was to simplify and standardize wholesale distribution service to eliminate legacy preferential treatment and to ensure that all PG&E customers are treated fairly and equally," Robison said. "We designed the updated tariff proposal to help achieve FERC's goal of ensuring reasonable rates, terms and conditions. We understand the City and County of San Francisco's concerns and have been working with them on a mutually agreeable resolution."

FERC headquarters in D.C. | © *RTO Insider*

The underlying case concerns PG&E's wholesale distribution tariff, which governs how wholesale distribution customers, such as San Francisco, accesses the company's services. Wholesale customers use PG&E facilities to access the CAISO-controlled grid to make wholesale sales and purchases, according to the order.

PG&E updated the wholesale distribution tariff's terms and conditions in 2020 and transitioned to a formula rate. San Francisco protested the update, arguing that PG&E proposed definitions of "upgrades" and "direct assignment facilities" were discriminatory.

The case has taken several twists and turns since 2020, including settlement discussions. The Oct. 16 order deals with two remaining issues:

- whether PG&E's treatment of the costs of upgrades to the distribution system under the wholesale distribution tariff is just and reasonable and not unduly discriminatory or preferential.
- whether PG&E's treatment of the costs of direct assignment facilities — facilities that are used by only a single wholesale customer — under the tariff is just and reasonable and not unduly discriminatory or preferential.

In agreeing with the administrative law judge, FERC said "PG&E's proposed treatment of the cost of upgrades violates the commission's cost causation and comparability principles and is therefore unjust and unreasonable."

"Specifically, we agree that under the definition of upgrades in the [wholesale distribution tariff], PG&E's retail customers may benefit from the use of the upgrades," the order stated. "Thus, consistent with the commission's cost causation principle, the costs of upgrades must be allocated among customers that benefit from the upgrade rather than directly assigned to the wholesale distribution customer that requested the upgrade."

What's Next

The order requires PG&E to revise its wholesale distribution tariff within 60 days.

On the issue of the costs of direct assignment facilities, FERC sided with the administrative judge's reasoning that because those facilities "solely benefit the requesting wholesale distribution customer" it is "therefore inappropriate to roll in installation costs for direct assignment facilities to the wholesale distribution revenue requirement or otherwise assign those costs to retail or other wholesale customers."

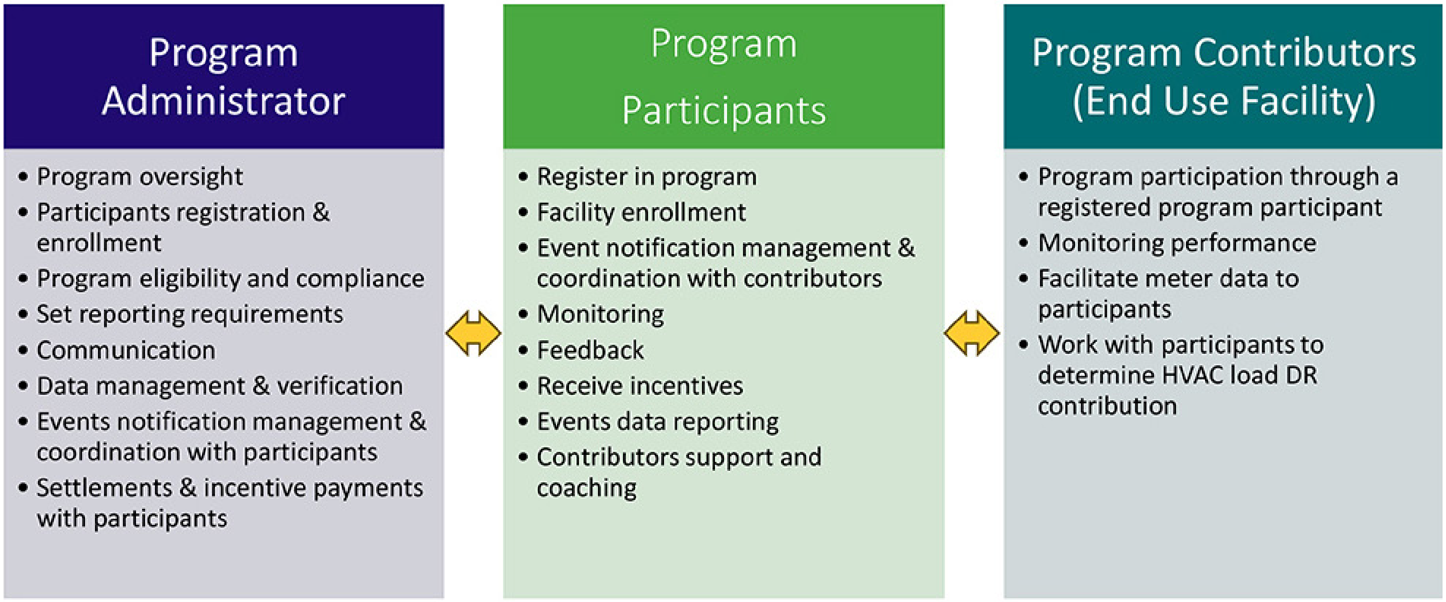
However, PG&E failed to show that it treats retail customers' facilities on the same basis and that wholesale customers end up shouldering some of the costs for retail facilities, according to the order.

"The presiding judge found that for PG&E's retail customers, PG&E does not assign itself the full costs of retail distribution line extensions," the commission wrote. "Instead, the costs of those retail customer-driven facilities are rolled into the wholesale distribution revenue requirement and allocated to wholesale distribution customers using the load ratio share methodology," the commission wrote.

"We affirm the presiding judge's determination that PG&E's proposed definition of direct assignment facilities in the [wholesale distribution tariff] does not comply with the commission's comparability principle and is unjust and unreasonable and unduly discriminatory or preferential," the order stated. "Additionally, we direct PG&E to submit a compliance filing revising the [wholesale distribution tariff] in accordance with the initial decision and this order, make refunds, and submit a refund report." ■

IESO Seeks to Expand Commercial DR

Focus on HVAC, Outside Capacity Market



Key roles for IESO's commercial HVAC DR program | *IESO*

By Rich Heidorn Jr.

IESO hopes to curtail 100 MW of commercial HVAC load in 2026 under a new program targeted at resources available during system peaks, but not for the full six-month commitment of the capacity market.

The grid operator outlined the Save on Energy Commercial HVAC Demand Response Program in an *engagement* session Oct. 16. IESO hopes the program, expected to launch in June 2026, will scale to 230 MW at commercial and institutional facilities (e.g., retailers, offices, universities) in 2027.

Program participants will be required to respond to up to 10 events of up to three hours on business days between June 1 and Sept. 30. The events will be "typically between 3 and 7 p.m.," IESO said in a *presentation*.

Why This Matters

Ontario is seeking to increase its demand response capabilities in the face of a projected 75% increase in electric demand by 2050.

They will be paid based on the average megawatts curtailed per season. Settlement will be based on local distribution company revenue meter data, using the average megawatt reduction from the top eight of 10 events.

Requirements

Program participants must aggregate at least 500 kW of demand response load capacity and be able to monitor and verify load reductions, collect metering data and communicate with "program contributors" — the end-use facilities reducing demand.

Following the ISO's first engagement session June 24, stakeholders called for flexible load eligibility and onboarding support for participants. The program will offer an incentive of $20/kW to offset contributors' costs for metering, monitoring and control systems.

Stakeholders also identified LDCs as "key partners for coordination [and] visibility," IESO said.

IESO's Mohammed Yousif said LDCs also can participate as aggregators. "We're not … limiting who participates into the program" other than the minimum 500-kW load, Yousif said. "LDCs may decide [on] different approaches."

Stakeholders supported a day-ahead standby notice with same-day activation by midday. A standby notice will be issued no later than noon the day before the event, with activation notices sent no later than noon on the day of the event.

Non-HVAC Resources

Yousif said the program rules will specify non-HVAC measures that also will be eligible for participation. "The program will be predominantly HVAC — maybe 75% comes from HVAC and 25% comes from non-HVAC," he said. "Battery energy storage … related to curtailment of HVAC systems could be considered as well."

Antoni Paleshi, senior energy performance specialist for WSP, asked how owners of new buildings can estimate their contributions without any energy history.

"This is a pay-for-performance program," Yousif said. "We could use the first few events as a way to … assess the estimate that is provided and adjust accordingly."

IESO expects to issue the program rules by the end of November and complete program readiness by April. ■

Battery Developers Seek Relief on IESO Ramp Limits

By Rich Heidorn Jr.

Storage developers in Ontario are pushing back on IESO's 100-MW/minute ramp limit for batteries, saying it will reduce their revenues.

IESO said the limit is needed to allow it to meet NERC standards requiring balancing authorities to keep system frequency at 60 Hz.

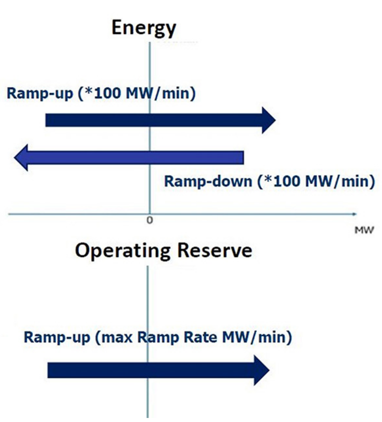
"IESO has experienced negative impacts to system frequency resulting from the fast-moving capabilities of BESS [battery energy storage systems]," the grid operator said in a *presentation* Oct. 16 on its Storage and Co-located Hybrid Integration Project, which will introduce a single bidirectional resource model for BESS.

The *initiative*, part of the ISO's *Enabling Resources Program* (ERP), initially will focus on electricity storage and hybrid generation-storage resources. It will replace the current two-resource model — which separates the withdrawal portion of the resource as load and the injection portion as a generator — with a single continuous offer curve. The current model creates operational challenges and reduces market efficiency, according to the ISO.

IESO plans to continue using its current 100-MW/minute up and down limit per facility under the new model.

3,000 MW of Storage Expected by 2028

The ISO noted that it expects 25 BESS facilities to join the grid in the near term,



IESO plans to continue using its 100-MW/minute ramp limit for battery energy storage systems supplying energy. There is no ramp limit when BESS is providing operating reserves. | *IESO*

with about 3,000 MW of contracted storage expected in service by 2028.

IESO relies on regulation services to compensate fast output changes from batteries, said Ihor Lopuch, a project adviser. "In some cases, ISO control room operators have had to take additional out-of-market control actions, such as constraining some resources or sending one-time dispatches to help rebalance the system," he said.

Storage operators first raised objections to the static ramp rates following an engagement session July 24. (See *IESO Seeks Feedback on Revised Storage Model*.)

In the most recent session, Travis Lusney, director of power systems for Power Advisory, representing the Energy Storage Resources Consortium, led the opposition. The *consortium's* 12 members include Capital Power, EDP Renewables, Brookfield Renewables and Northland Power.

Lusney asked the ISO to determine the impact of increasing the ramp limit from 100 MW and whether there is an optimal limit that could maintain area control error while offsetting higher costs of regulation capacity. "Can it be 150, 200 [MW]?" he asked.

Lusney also asked for data on how often IESO will dispatch storage resources for operating reserves (OR) versus energy.

"The answer that I've gotten consistently is OR resources are … scheduled on the sideline to be there, but their dispatch instructions are only energy, and that there is no OR dispatch instruction," Lusney said. "Part of that may have had to do with the previous market design, and that might be changed, but it's not clear that there's any historical information to understand how often an energy storage resource may receive an energy dispatch and be limited in that 100-MW/minute step up versus an OR dispatch that would allow them to ramp to their full capability."

Lusney said battery operators face lost revenue because the limits negate the competitive advantage of their ramp speeds. "In a market design that encourages more price fidelity … this is quite restrictive on the competitive advantage of storage," he said.

Why This Matters

IESO expects 25 battery energy storage systems to join the grid in the near term, with about 3,000 MW of contracted storage expected in service by 2028.

'In Alignment'

IESO officials said the 100-MW limit is "in alignment" with other ISOs, including CAISO and SPP.

Tyler Chuddy, project superviser, said the ISO has limited analysis of batteries' ramp impacts because it expects numerous BESS facilities to come online at the same time. "One hundred megawatts per minute means like a 500-MW shift in your production over one interval, which is pretty substantial," Chuddy said.

He asked Lusney to provide details on how the ramp restrictions would result in lost revenue for battery operators. Lusney agreed to provide some examples from the consortium.

The current phase of the project, which may run as long as through 2028, will seek to establish the single resource model and set rules on state-of-charge management. Phase 2 will consider ways to allow batteries to also offer frequency regulation, which the ISO uses to correct supply-demand imbalances.

Lusney urged the ISO to consider batteries as a potential solution to the ramping challenges.

"If it's a regulation capacity challenge driven by the fast response of the energy storage, can energy storage provide some of that regulation capacity in its dispatch instruction?" he asked. "[I recognize that] it's not part of the current engagement process, but it seems like they are interconnected."

Next Steps

IESO is seeking written feedback to its proposed rules by Oct. 30 deadline at *Engagement@ieso.ca*. The next engagement session for the project is expected in the first quarter of 2026. ■

IESO Removes Credit Rating Requirement for TSF Entry

By Michael Brooks and Rich Heidorn Jr.

Why This Matters

IESO says initiating competition — a directive from the Minister of Energy and Mines' Integrated Energy Plan — will lower costs and produce innovation.

IESO has removed a credit rating requirement for prospective bidders to enroll in its Transmitter Selection Framework Registry (TSF-R), a prequalification mechanism for the ISO's competitive procurement that is expected to begin in 2026.

Removing the requirement will ensure that all applicants are "assessed using consistent financial criteria," IESO officials said in an *engagement session* Oct. 15.

"This allows us to evaluate organizations consistently through these early phases, but it's expected that credit rating requirements will be expected and introduced as a requirement at the time of" the request for proposals, said Denise Zhong, IESO senior manager for resource adequacy and sector evolution.

IESO officials said the change was made in response to feedback after its stakeholder engagement in June. (See *IESO Moving Forward with Competitive Tx Plans*.) The TSF-R opened July 31.

"Concerns were raised around the current credit rating criteria within the TSF Registry that [they] may be too restrictive at this stage of the process, and it seemed that it was required for some but not all," Zhong said.

Throughout their presentations, Zhong and her colleagues emphasized the importance of Indigenous participation and support for projects. They said since the June engagement, the ISO has continued talks with Building Ontario Fund (BOF) and Canada Infrastructure Bank (CIB) to develop ways to encourage Indigenous participation and provide loans to developers of TSF projects.

The BOF is administering the Indigenous Opportunities Financing Program (IOFP) — formerly the Aboriginal Loan Guarantee Program — which provides credit support to help Indigenous corporations attract lenders.

"The IOFP is not a loan or a grant program," said Andrew Lee, IESO senior adviser for resource acquisition. "The IOFP is a form of credit support intended to enhance Indigenous corporations' credit worthiness and attract lenders willing to provide a loan."

Three loan guarantees totaling $327 million have been provided by the fund through September, Lee said, including most recently one for the Chatham-Lakeshore transmission line, a 49-km, double-circuit 230-kV line in southwestern Ontario.

IESO says initiating competition — a directive from the Minister of Energy and Mines' *Integrated Energy Plan* (IEP) — will lower costs and produce innovation. The ISO is working with the ministry to identify the first transmission project to be opened to competition, with a focus on the South and Central Bulk Study, with recommendations scheduled for late 2025, and the North of Sudbury and Eastern Ontario bulk studies, both expected in early 2026.

But most of the 1,500 km of new transmission lines planned or under development will be awarded to incumbent transmitters.

'Partial Contracting' Model

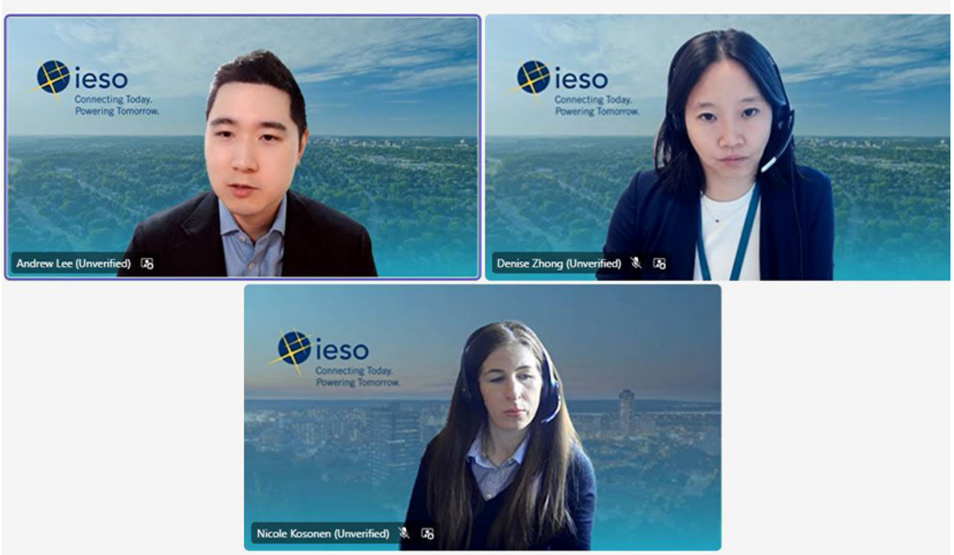
The ISO announced in June that it had decided on a "COD+10" partial contracting model, in which the winning bidder will receive a contract covering all costs of financing, designing, building, operating and maintaining the line for the first 10 years of commercial operation.

Bidders will be asked to submit 10 annual revenue requirements (ARRs) for the initial 10 years of operation. In year 11, the contract will transition to traditional rate regulation under the Ontario Energy Board (OEB), which will review the prudency of ARRs going forward.

The model will include binding commitments for cost management, scheduling and Indigenous participation, officials *said*.

IESO also has been consulting with the OEB to develop the regulatory framework for the program, including exempting TSF-contracted transmission projects from "leave-to-construct" requirements.

"One of the key recommendations coming out of the TSF is to remove the leave-to-construct requirement during project development phase for TSF projects,"



IESO's Andrew Lee, Denise Zhong and Nicole Kosonen | *IESO*

Zhong said. "This change is intended to reduce timelines in the development phase, recognizing that, again, a procurement process overall will require additional time and careful execution."

The ISO also has been meeting with transmitters, financiers, and engineering, procurement and construction firms to inform the design of the program.

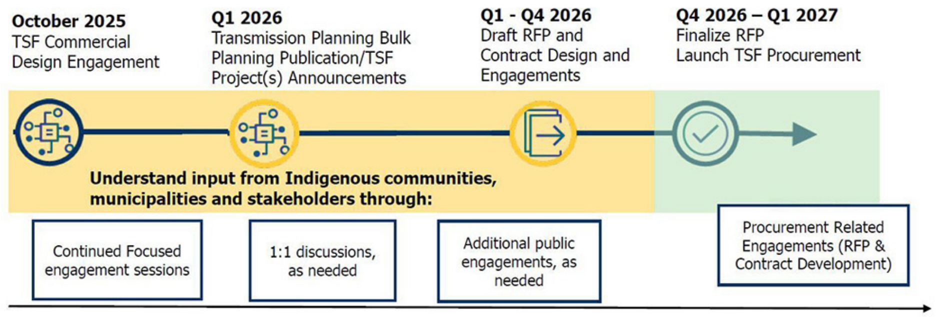
Routing, Cost Containment

IESO said it will specify terminal connection points for projects but will not prescribe routes.

"In some cases, a corridor may have been identified and/or protected by the Ministry of Energy and Mines," the ISO said. "Such a corridor will not preclude other route alignments as determined through field studies and/or community engagement."

IESO said it is considering cost-containment provisions and ways to manage cost adjustments to balance "cost certainty and flexibility for legitimate changes."

It asked stakeholders for feedback on whether it should set cost caps or allow



IESO's timeline for its TSF procurement | *IESO*

developers to propose them.

To protect ratepayers, IESO said it will monitor developers' performance and may reduce their payments if they fail to meet contractual benchmarks regarding availability (based on outages) and transfer capability.

"Unlike the rate regulated cost of service model where reasonable operational and maintenance costs are reimbursed to the transmitter, the IESO foresees a potential risk of underinvestment in maintenance and operation from transmitters as an approach to improving transmitter profit margins," it said.

Feedback

Sonny McGinnis complained about difficulty communicating with the ISO. McGinnis, who was representing the Anishnaabeg of Naongashiing in northwestern Ontario, said he "tried calling after our sessions months ago. I could never line up with anyone. Nobody knew what the heck I was talking about. … It can't be just lip service we're getting."

Stakeholders should provide written feedback on the TSF plan to *engagement@ieso.ca* by Nov. 5. IESO plans to share solicitation documents and contract term sheets in an engagement session in January. ■

NEPOOL Members Offer Amendments on ISO-NE Capacity Reform Project

By Jon Lamson

NEPOOL members have proposed several amendments to the first phase of ISO-NE's capacity market overhaul prior to the scheduled Markets Committee vote on the RTO's proposal in November.

The amendments presented to the committee Oct. 16 include proposals to allow generators to submit capacity offers reflecting physical limits throughout during hot weather; adjust the methodology for calculating the capacity offer price threshold (COPT); and extend the length of time resources can hold onto interconnection rights while undergoing major repairs.

The first phase of ISO-NE's Capacity Auction Reform (CAR) project is centered around shifting the Forward Capacity Market to a prompt design and updating the resource retirement process. The second phase is focused on accreditation changes and instituting a seasonal market. Both phases are intended to take effect in the 2028/29 capacity commitment period. (See *ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes*.)

Why This Matters

Stakeholders are looking to make last-minute tweaks to ISO-NE's prompt capacity market proposal that are aimed at addressing complications of the sweeping market changes.

Ambient Air De-list Bids

Bruce Anderson of the New England Power Generators Association (NEPGA) argued that ISO-NE should extend existing rules and practices allowing generators to submit capacity offers reflecting reduced generating capabilities at temperatures above 90 degrees Fahrenheit.

The RTO's current proposal requires all qualified resources to offer all available capacity in annual auctions and would not maintain the option for generators to de-list capacity during periods of high temperatures.

"Without carrying forward the exemption, a resource will unnecessarily be required to submit a cost workbook for megawatts it is physically unable to produce at those high ambient temperatures," Anderson told the committee.

To address the issue, NEPGA has proposed adding language allowing participants to "identify and submit a price-quantity pair(s) in a capacity offer specifically attributable to and up to the megawatt amount that the lead market participant expects will not be physically available due to ambient temperature effects."

Several members of the generation sector expressed support for the amendment, while some stakeholders said it ultimately will be important to address temperature effects in the accreditation phase of the CAR project.

Chris Geissler, director of economic analysis at ISO-NE, said the RTO does not yet have a firm position on the amendment and is still considering the proposal. He added that ISO-NE's existing proposal to not carry forward ambient air exemptions was motivated by a desire for more consistency across different segments of capacity.

Capacity Offer Price Threshold

Ben Griffiths of LS Power proposed a transitional methodology for calculating the COPT for the 2028/29 commitment period that he said would help address issues related to outdated price inputs.

The price threshold is intended to protect against market power; participants offering above the threshold price are required to submit a cost workbook to the Internal Market Monitor.

ISO-NE plans to maintain its methodology for calculating the threshold as it transitions to a prompt auction. Under the existing methodology, the 2028/29 threshold would be based in part on the prices from the last Forward Capacity Auction, which will have been held about four years prior to the first prompt auction.

Griffiths said he is concerned this will lead to an outdated threshold value, especially after capacity shortfall events over the past two summers caused some generators to accrue costly performance penalties, which has caused some participants to speculate that capacity costs will increase in the future to account for these risks.

He proposed that ISO-NE set the threshold for the 2028/2029 commitment period at "at a fixed price of $4.984/kWm," which "represents the simple average of observed clearing prices in the summer 2025 ARAs [annual reconfiguration auctions] and theoretical common value component estimates derived from the same auctions."

The common value component equals "the expected value of scarcity revenues under [Pay-for-Performance]," Griffiths noted in a *memo* published prior to the meeting.

He said the close alignment of the ARA and common value component prices "supports a strong case for using this value."

Responding to the proposal, Geissler said the RTO's current proposal is to extend the existing methodology for the threshold. However, he said ISO-NE is amenable to considering transitional changes to address a time lag in the data, especially if there is broad stakeholder support.

Geissler said ISO-NE plans to consider changes to the threshold during the accreditation phase of CAR. However, if the RTO cannot finish the accreditation phase in time for the 2028/29 commitment period, and it identifies issues related to stale data used in the COPT, the RTO would look to address the issue prior to the auction, he said.

Also at the meeting, Andy Gillespie of Calpine reiterated his *proposal* for ISO-NE to base the threshold strictly on the common value component. He acknowledged that this could lead to a threshold value significantly higher than the clearing price of past FCAs but stressed that the threshold should be a forward-looking metric.

"This method is based on ISO-based,

forward-looking, objective data" and is "often cited by ISO as the basis for calculating PFP opportunity cost," Gillespie said, adding that the methodology could "be used regardless of auction format or accreditation methodology."

Geissler said ISO-NE is not supportive of a broader change to the COPT methodology, which it considers to be outside the scope of work for the first phase of the CAR project.

3-year Rule

Griffiths also advocated for a *change* to ISO-NE rules that automatically deactivate resources that do not run for three straight calendar years. He expressed concern that recently proposed changes to the RTO's repowering rules could cause resources facing extended repairs to lose their interconnection service.

Three- to seven-year wait times for turbines and transformers "make compliance with the strict three-year clock unrealistic for facilities facing catastrophic outages," Griffiths said.

While resources could seek a waiver from FERC to ISO-NE's three-year rule, "FERC's waiver process is uncertain and ill-suited to this situation," he argued.

Griffiths proposed introducing "a bounded extension" of up to six years for resources making "good-faith restoration efforts."

To be eligible for such an extension, resources should have to demonstrate "due diligence, including at-risk expenditures, in pursuit of permitting, licensing and construction necessary to restore the resource to commercial operation," he proposed.

Several stakeholders said they are open to the change but would want to ensure there is language to prevent resources from using the extension simply to hold onto interconnection rights and prevent other resources from entering the market.

ISO-NE agreed the issue warrants additional discussion but said that it should be done outside of the CAR process.

Griffiths also offered an *amendment* to clarify ISO-NE's authority over the interconnection rights of state-jurisdictional resources that have been inactive for more than three years. He advocated for new tariff language "to protect jurisdictional integrity" and to "enable equal treatment for state resources under the proposed deactivation language." ISO-NE, however, said that is outside the scope of the CAR project.

Accreditation Updates

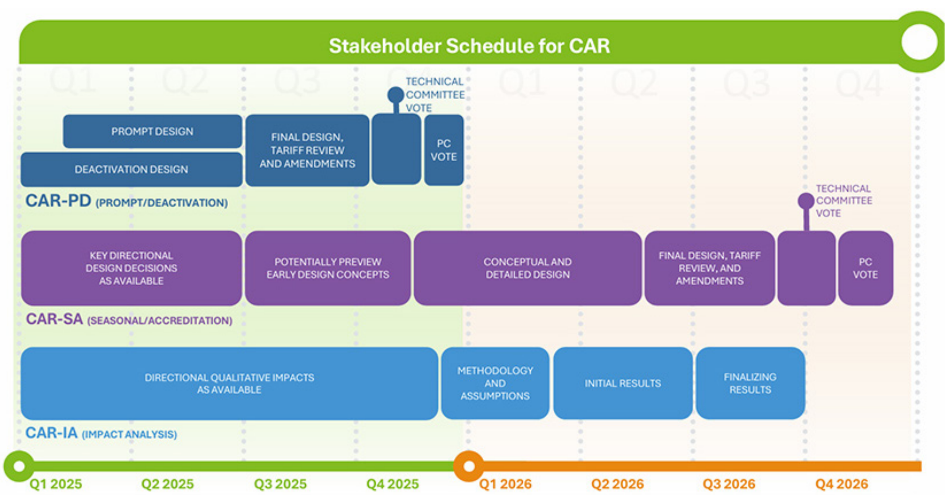
Also at the meeting, ISO-NE outlined its plans to calculate seasonal forced outage rates in the new accreditation framework.

Equivalent forced outage rate on demand (EFORd) is intended to quantify resources' likelihood of having an outage when called upon and is a key input into resources' overall accreditation value, noted Steven Otto, manager of economic analysis at ISO-NE.

The RTO plans to *calculate* EFORd values based on data from the previous five years. For resources that lack enough data, it plans to use class averages from the New England generation fleet to fill in any gaps, Otto said.

"Conceptually, the mechanics of seasonal EFORd calculations will be identical to the existing mechanics for annual EFORd calculations, except that the calculation will be done for a given season with historical data only from that season," Otto said.

He added that "for most resources, the differences between their annual and estimated seasonal EFORd values are small."



ISO-NE Capacity Auction Reform stakeholder schedule | *ISO-NE*

Maximum Capability

ISO-NE also discussed its methodology for calculating resources' maximum capability, which "represents a resource's physical supply capability and reflects changes in a resource's capability due to changes in its physical attributes."

To generate accreditation values for each resource, ISO-NE plans to multiply resources' maximum capability by their marginal reliability impact ratio, which compares the reliability benefits of the resource to a hypothetical "perfect" capacity resource.

Maximum capability would be calculated seasonally in the summer and winter. In the summer, it would equal each resource's maximum recorded hourly net output from the past three years when temperatures are over 80 F. Winter maximum capability values would be based on maximum hourly output when temperatures are below 32 F.

ISO-NE also plans to allow resources to schedule an audit to determine their maximum output.

For active demand resources, the maximum capability will be based on maximum hourly performance in the winter and summer from the previous three years. The temperature constraints would not apply to these resources, as they do not self-schedule, and are not guaranteed to run at their full capacity at a certain temperature in any given season, ISO-NE said.

The maximum capability for energy efficiency resources would be based on performance estimates from ISO-NE's efficiency database.

ISO-NE said the three-year lookback period for maximum capability values should give resources that run infrequently enough time to demonstrate their full performance capabilities while also capturing recent performance trends. ■

New Report Outlines a Road Map for Interregional Tx in the Northeast

By Jon Lamson

A new report outlines a high-level road map for cross-border interregional transmission planning in the Northeast, making the case for more coordinated planning processes across sub-regions and regulatory environments.

The analysis, authored by the energy consulting firm Power Advisory, was commissioned by the Northeast Grid Planning Forum. The forum is an initiative of Nergica, a Quebec-based clean energy research organization, and the Acadia Center. (See *New Initiative Focuses on Interregional Tx Coordination in the Northeast*.)

“Provinces and states could benefit through enhanced coordination and transmission project development that optimizes utilization of existing resources and enables development of new clean energy sources,” Power Advisory wrote.

While studies have shown significant *potential* for increased interregional transmission throughout the Northeast, “fragmented planning processes and challenges presented by differences in regulatory structures” have limited states and provinces’ ability to fully realize these benefits, the authors wrote.

They emphasized the need to build trust, increase information access and establish mechanisms to facilitate transmission partnerships across regions and borders.

“A collaborative planning framework will require new approaches to sharing information and will require harmonizing planning processes to meet the requirements and planning horizons of each jurisdiction,” Power Advisory wrote. “Transparency and engagement will provide confidence in identified needs among jurisdictions and stakeholders.”

The report highlights several recent larger-scale transmission planning efforts as evidence of growing interest in interregional planning.

In June, the Northeast States Collaborative on Interregional Transmission, which includes nine states, issued a *request for information* (RFI) to identify “potential interregional transmission opportunities … that improve grid reliability, support economic growth and reduce costs for consumers.”

Why This Matters

The growth of renewable generation across the Northeast likely will increase the cost justification for interregional transmission projects aimed at preventing congestion and enabling access to lower cost power.

The states asked for input on potential cost allocation methods and wrote that responses to the RFI will “inform potential future solicitations or transmission planning activities.”

International cooperation around transmission planning also has increased. In 2024, the New England Governors and Eastern Canadian Premiers agreed to *reconvene* the Northeast International Committee on Energy, directing the committee to establish working groups “to pursue regional collaboration and planning on the topics of transmission, offshore wind supply chain and hard-to-decarbonize sectors.”

In Atlantic Canada, top politicians are eying a massive buildout of offshore wind generation, which would require large-scale interregional transmission developments to move the power to load centers in Canada and New England.

According to a *strategic plan* published by Nova Scotia, researchers have identified offshore wind sites that could host 62 GW of generation. Nova Scotia has proposed a 5,000-MW first phase of development, requiring an estimated $40 billion in capital investment to build the generation and $20 billion to build the associated transmission.

These recent efforts “indicate recognition by the key jurisdictions that current transmission planning approaches are constrained and insufficient and need to change to realize the benefits of broader regional energy system integration,” Power Advisory wrote.

To select projects, existing regional competitive transmission solicitation processes could be aligned to allow for interregional projects, or new processes could be stood up, the authors wrote.

“The recently established ISO-NE Longer-Term Transmission Planning (LTTP) process provides an instructive model for need identification across a multi-jurisdiction region,” they said.

ISO-NE is evaluating project submissions for the first iteration of its LTTP process, which is focused on increasing transmission capacity in Maine and enabling the interconnection of onshore wind generation. (See *ISO-NE Reveals 1st Details of Long-term Transmission Proposals*.)

States and provinces also would need to establish cost sharing processes and could take inspiration from Europe’s cross-border cost allocation methodology, the authors wrote.

Cost allocation “should ensure full consideration of all benefits evaluated in each participating jurisdiction,” including “reduced production costs, avoided capacity costs, avoidance of alternative transmission investments, improved transmission system efficiency, reliability and other benefits,” the authors added.

To address the challenges of determining needs, selecting projects and allocating costs across regulatory authorities, states and provinces should establish “a joint coordination agreement” that “formalizes collaboration and provides a clear mandate for agency staff regarding the scope of future work,” Power Advisory concluded.

This could mirror the memorandum of understanding underpinning the Northeast States Collaborative and could lay the groundwork for answering more technical questions related to modeling, information sharing and aligning existing processes, they wrote. ■

Stakeholders Ask MISO to Pause '25 Queue to Get a Handle on 4-Year Backlog

By Amanda Durish Cook

Why This Matters

Multiple stakeholders say it's a good idea for MISO to take a time out on studying the 2025 collection of generation proposals in the interconnection queue to push through the remaining 2021 and 2022 project entries.

Stakeholders asked MISO to consider putting a hold on processing generation project proposals entering the interconnection queue in 2025 to focus on the bottlenecks formed from the 2021 and 2022 queue classes.

At an Oct. 16 Interconnection Process Working Group meeting, multiple stakeholders told MISO it may be prudent to wait to kick off studies on the 2025 queue cycle until it's further along with the study of projects that entered three and four years ago.

New Leaf Energy's Adam Stern said MISO has done a lot recently in terms of interconnection queue rule changes and wondered whether MISO can juggle all four queue cycles, its new automated study process and its more stringent requirements for developers.

"I think what we've heard recently is that the older clusters are still moving slowly because of their size and they're subject to old rules," Stern said.

He said MISO might consider pausing to pay "more attention to the older clusters" and clear out the backlog before turning attention to the 2025 entrants.

As of September, MISO's interconnection queue contained 1,127 projects at 215 GW, down from more than 300 GW earlier in 2025. MISO leadership said to expect more withdrawals in the coming months due to the federal phaseout of renewable energy tax incentives. (See *MISO Interconnection Queue Drops to 215 GW on Tax Incentive Phaseout*.)

MISO's 2023 cycle is down to 102 GW from the 123 GW of projects that entered. The whopping 171 GW of projects that entered in 2022 is down to just 75 GW, while the 77-GW 2021 cycle has been reduced to 38 GW. The grid operator skipped acceptance of a 2024 cycle while it tried to get a handle on study delays and design a megawatt-capped queue that could sort out projects over one year instead of three to four years.

MISO closed its application window Oct. 7 for the 2025 cycle and has begun reviewing the project applications for completeness. The cluster of projects will raise queue totals.

MISO staff at the meeting said the RTO's prerogative is to work as quickly as possible to process the cycles simultaneously. However, Aneta Godbole of MISO's resource utilization team asked if stakeholders wanted a future discussion on MISO possibly filing a FERC waiver to hit pause on the 2025 cycle.

Entergy

Savion's Abhishek Dinakar seconded the request for MISO to clear the backlog and finish the 2021 and 2022 queue cycles before focusing on the 2023 and 2025 cycles.

"It's kind of an unworkable amount of uncertainty" in the analyses, EDF Renewables' Anton Ptak said of the RTO simultaneously trying to complete studies on four queue cycles, when cycles contain projects that are contingent on higher-queued projects' grid upgrades.

Ptak said MISO should put as much effort as possible into finishing the legacy queue cycles.

"That's critically important," he said.

Clean Grid Alliance's David Sapper said it makes sense to clear the older cycles. But he said he worried the "vibe" he's getting from MISO is that it sees the 2021 and 2022 queue cycles as so complex and problematic that the RTO ultimately would conclude the answer is opening another queue express lane.

"I worry that it's just setting up us for more" generation projects in the expedited queue lane, Sapper said.

MISO's Kyle Trotter said MISO has no plans to continue the queue fast lane once it hits its 68-project limit. ■

FERC Orders MISO to Describe Merchant HVDC Planning Considerations

Commission Rebuffs Most of Invenergy's Ask to Compel MISO to Integrate Grain Belt Express in Tx Planning

By Amanda Durish Cook

FERC has ruled that MISO must name a point in development and describe how it will consider merchant HVDC lines in its transmission planning; however, the commission declined to order a more complete incorporation of the Grain Belt Express HVDC line in MISO's recent transmission planning.

The directive to MISO was the sole issue FERC granted from Invenergy Transmission's 2023 complaint, which sought to force MISO to consider the Grain Belt Express in its transmission planning (*EL22-83*).

FERC said Invenergy successfully argued that MISO's tariff is unfair "insofar as it does not address when and how [merchant] HVDC transmission projects are incorporated into MISO's transmission planning models." The commission told MISO to decide on a juncture and explain how it would account for merchant HVDC lines in transmission planning and add it to the planning protocol section of its tariff within 90 days.

Elsewhere in its Oct. 16 order, FERC decided that Invenergy did not meet its burden to prove that MISO fumbled on its planning practices regarding the proposed 800-mile, 5,000-MW line.

Invenergy argued that MISO has an obligation to incorporate "advanced-stage" merchant transmission facilities in its base case analysis performed under the annual MISO Transmission Expansion Plan (MTEP) and in long-range transmission planning.

The company claimed MISO is forcing ratepayers to foot the bill on regionally planned transmission projects that could be redundant alongside planned merchant HVDC projects. Invenergy said MISO should not be able to ignore merchant transmission in its MTEP and long-range transmission planning exercises when MISO's tariff prescribes that MISO should assess a "quantifiable benefit" of an "enhancement to the MISO transmission system."

Invenergy had asked FERC to order MISO to edit its tariff so that it incorporates all advanced-stage merchant transmission projects in its annual and long-term transmission planning. It also asked FERC to direct MISO to perform an after-the-fact sensitivity analysis for MISO's two long-range transmission portfolios that considers Grain Belt.

MISO said it performed such a sensitivity analysis for the second long-range portfolio and found no reason to change any of its project recommendations. FERC accepted MISO's analysis and declined to mandate more studies.

Invenergy said MISO's second long-range portfolio contains a 765-kV line in Missouri that duplicates some of Grain Belt's capabilities. It said MISO planned the line over 2024 even though Invenergy had a transmission connection agreement with MISO. Invenergy also said MISO's first long-range transmission portfolio from 2022 included three projects at a combined $1.46 billion in northern Missouri that would return just 40 cents for every dollar spent on them once Grain Belt is transporting power.

Invenergy argued that MISO's interpretation of its tariff "leads to an absurd result and unjust and unreasonable rates" and that MISO's decision not to account for Grain Belt betrays optimized transmission planning.

FERC said Invenergy did not demonstrate that MISO's evaluation of the trio of projects was incompatible with its tariff requirements. The commission also noted that MISO assesses the benefit-to-cost ratio on a portfolio basis and doesn't produce ratios for individual projects. FERC also pointed out MISO does not assess a line's ability to cancel out lower voltage upgrades of 230 kV or below, per its long-range transmission planning procedures.

Commissioner Lindsay See, while concurring with the order, put MISO on notice that additional analyses are a smart move to prove the worth of several billion-dollar transmission portfolios.

"When billions of dollars in infrastructure projects are at stake, more confidence in the accuracy of MISO's planning and cost-benefit assumptions is not too big an ask. Judiciously using sensitivity analyses to help ratepayers get the most value for their money may be one tool well worth its weight," See wrote.

See said it's unclear whether MISO "is providing stakeholders and the MISO Board with the best information possible to assess true grid needs" when it unveils a long-term transmission portfolio. She cited the pending North Dakota-led complaint questioning the value of MISO's $22 billion, mostly 765-kV second long-range transmission portfolio. (See *MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan*.)

Invenergy representatives have said for years in MISO public meetings that the RTO's transmission planning modeling is deficient because it didn't factor in Grain Belt Express operations. (See "The Grain Belt Express Question," *Members Call for More Tx Expansion Following MISO's $20B LRTP Blueprint*.)

MISO did not include impacts from the Grain Belt Express merchant HVDC line in any of its 30-plus annual models under its 2024 Transmission Expansion Plan. MISO said Grain Belt Express did not sign its transmission construction agreement until about three weeks after the Feb. 1 cutoff date for members to submit projects for inclusion in MTEP 24 planning models. (See *FERC OKs Grain Belt Express Connection Agreement with MISO; Invenergy Displeased with 2030 Target*.)

MISO said it would include only approved segments of Grain Belt in its MTEP 25 planning modeling. Some MISO stakeholders have said Grain Belt Express stands to deposit substantial wind energy from Kansas into MISO.

Earlier in 2025, the U.S. Department of Energy Loan Programs Office revoked a $4.9 billion conditional loan commitment for Grain Belt. (See *DOE Pulls $4.9B in Funding for Grain Belt Express*.) Invenergy has vowed nevertheless to move ahead with the project. ■

Hawley Asks Ameren if Ratepayers are Covering Data Center Costs

By Amanda Durish Cook

U.S. Sen. Josh Hawley (R-Mo.) has requested that Ameren explain whether its residential ratepayers are picking up the tab for grid upgrades necessary to accommodate data centers and other large industrial customers.

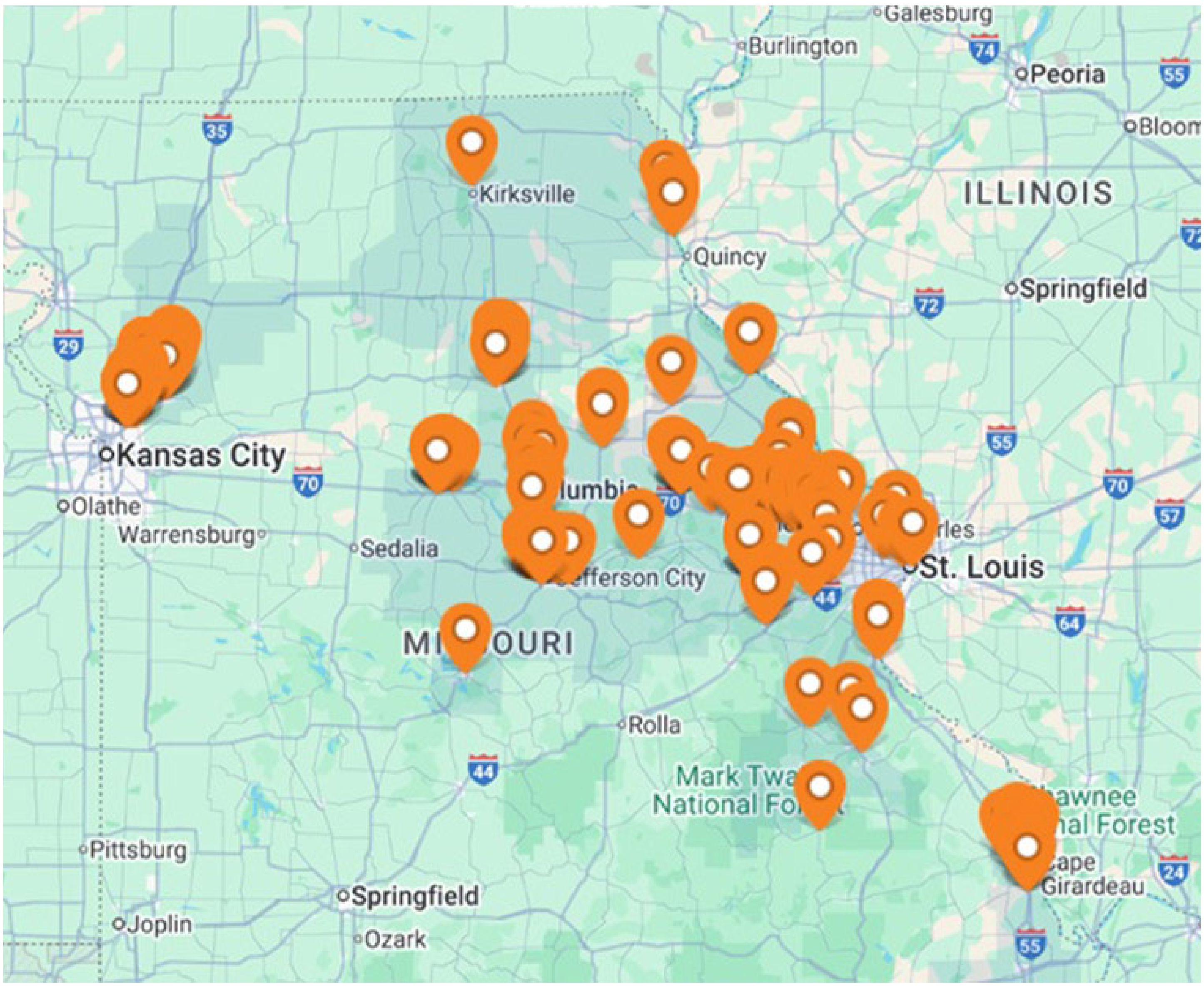
Hawley *sent* a letter to Ameren CEO Martin Lyons on Oct. 15 expressing concern that residential customers are shouldering cost hikes and facing shutoffs while Ameren "pursues expensive corporate projects."

What's Next

Ameren Missouri said it would file more testimony in a case before the state's Public Service Commission explaining how it would prevent costs associated with data center demand from being passed on to ratepayers.

"Ameren is seeking dramatic rate increases in order to supply massive data centers and industrial users. Recent reporting indicates that Ameren cut electricity to thousands of Missouri households in September while simultaneously pursuing lucrative arrangements with corporate users," Hawley wrote, adding that ratepayers should not be "forced to subsidize corporate projects while struggling to keep their lights on."

Hawley was apparently referring to a *report* by KSDK in St. Louis that Ameren cut off power to 14,999 customers in



Ameren Missouri maintains an online map of available industrial sites for economic development. | *Ameren Missouri*

September and 14,375 in August for nonpayment, according to Missouri Public Service Commission data. Meanwhile, Ameren *told* the PSC in late August that about 15 GW worth of load is under construction or being studied for interconnection in its service territory. It noted that included "organic load growth from residential, commercial and industrial customers, as well as new manufacturing and data center loads."

The senator claimed that "Ameren's current request before the Missouri Public Service Commission would raise electric bills for residential customers by roughly 15% — a staggering increase for families already squeezed by inflation." He asked if this was because of the "considerable" power demands from new data centers. He also asked whether Ameren has analyzed how industrial contracts impact residential rates and if it has implemented protections to ensure that the infrastructure costs for large industrial customers are not passed on to residential customers.

"Has Ameren considered prioritizing rate stability for households before approving discounted contracts for data center clients?" Hawley asked. He added that he expected answers by Oct. 29.

Ameren Missouri does not have an open rate case. The PSC did grant the utility a $355 million rate increase in April, less than the $446 million it requested in 2024. The new rates took effect in June, with the average residential customer experiencing an approximate 11% increase (about $17.45) per month.

And Ameren has applied with the PSC to introduce new rates for data centers and other large loads. Commission staff have said that the utility's plan lacks protections that would prohibit passing along the costs of new, expensive power plants to ratepayers and could raise electric bills by an estimated $22 million annually (*ET-2025-0184*).

"Captive ratepayers should not pay unreasonably for those upgrades, nor should existing ratepayers be caught having to pay for any potential stranded or under-utilized resources built to serve anticipated large load customers," Missouri PSC Director of Industry Analysis James A. Busch said in testimony. Busch added that total electricity infrastructure costs could "easily exceed" $1 billion for just one large load customer.

PSC staff in September recommended that regulators reject the proposal.

In an email to *RTO Insider*, Ameren said it "obviously" disagrees with staff's position and said it would file testimony to address the analysis. The company said its plan "aims to reasonably ensure large electric load customers pay their fair share of service costs, protecting other customers from unjust or unreasonable charges, in alignment with Missouri Senate Bill 4."

That bill, which went into effect in April, contains a provision that large load customers cannot unjustly or unreasonably raise the costs of service for the remainder of a utility's customer base.

Ameren also disputed Hawley's worry that it would subsidize data center demand through residential bills.

"Data centers are required by law to pay rates that the Missouri Public Service Commission has determined reasonably cover their fair share of energy costs to serve them. Ameren Missouri is not offering these businesses any discounts. The infrastructure costs to connect large data centers to the grid are not passed on to other customers," Rob Dixon, senior director of economic, community and business development, said in a statement to *RTO Insider*.

In previous *testimony*, Ameren Missouri Senior Director of Regulatory Affairs Steven Wills said the utility's proposed large load tariff framework is "designed such that these large load customers are reasonably expected to pay their fair share over a long enough term to justify investment in long-lived generating assets."

Under the plan, prospective customers with demand of 100 MW or more would enter into long-term electric service agreements for at least 15 years and be billed for a minimum of 70% of the contracted capacity listed in the agreement.

Wills said the terms of the large load agreements "ensure a reasonable level of revenues over a sufficient term to reasonably assure that other customers will not bear any unjust or unreasonable costs associated with the acceleration of new generation that will need to occur to integrate the loads onto the system."

Ameren did not address Hawley's inquiry as to whether it has analyzed how industrial contracts impact residential rates. ■

MISO Tries to Clear Up Assortment of New DR Rules

By Amanda Durish Cook

Can't keep all of MISO's new demand response rules straight? You're not alone.

The grid operator convened a stakeholder workshop Oct. 14 to go over new requirements for demand response resources heading into the 2026/27 planning year.

After multiple instances of fraud and misrepresentation from DR in MISO's capacity market, the RTO has spent months developing stricter rules to deter abuse.

The RTO has made:

- A March filing seeking to discourage nonexistent or overstated curtailments by requiring proof of contracts and hourly meter data while instituting reference levels for DR resources so they cannot inflate baselines. FERC accepted the stricter rules in July (*ER25-1729*).
- An April filing to put an end to MISO allowing load-modifying resources to also identify as emergency demand response and collect extraneous capacity payments. FERC also accepted the changes in July (*ER25-2050*).
- An April filing to divide load-modifying resources into fast and slow categories for capacity accreditation, with the faster resources receiving higher accreditation values. The pending filing wouldn't take effect until the 2028/29 planning year (ER25-1886). (See *MISO Approaching LMR/DR Accreditation Based on Availability*.) FERC in September decided it needed more information on the proposal's inner workings and issued a deficiency letter.
- A July filing to mandate its demand response to make real-world demand reductions for tests instead of submitting mock tests to prove capability. (See *MISO Tries to Ward Off DR Fraud with New Testing Regime*.) FERC hasn't yet decided whether to accept MISO's proposal and issued an August deficiency letter to glean more information. The new testing rules would apply retroactively for any tests after July 15, if MISO's proposal wins approval (ER25-2845).

MISO plans to file at FERC for permission to more consistently dole out monetary penalties when a DR resource delivers less than promised, effective June 1, 2026. It also plans to bar energy efficiency from participating in its capacity auctions. (See *MISO to Axe Energy Efficiency from Capacity Market*.)

MISO senior market design economist Joshua Schabla reviewed new rules stemming from the filings that pertain to DR contracts, broader penalties, testing and providing MISO with documentation. MISO included the end of mock testing and stepped-up monetary penalties in its roundup, though those rules don't have FERC approval yet.

Compass Mining's new, 7.5-MW bitcoin mining facility in Minnesota participates in demand response. | *Compass Mining*

Why This Matters

MISO dedicated a stakeholder workshop to the slate of tighter rules it plans to enforce on its demand response for the 2026/27 capacity auction. The RTO hopes to ward off any future market manipulation.

Docs and Data

Before summer 2026, MISO will insist on more descriptive documentation for DR that details the operating procedures used to curtail load, how the market participant communicates with the facility making the cuts, the expected time to draw down the load and confirmation that the load can be held at a minimum amount for four consecutive hours.

"What we need to see is that the persons physically responsible for curtailing the load understand what they need to do and how they will do it; it does not need to provide confidential information but should be specific enough that a reasonable third party feels confident the facility knows what they're doing," Schabla said of the required documents.

MISO also will require written verification from facility owners that real power tests reflect what they expect to curtail if called upon by MISO.

Schabla pointed out that DR resources voluntarily participate in MISO's capacity market and receive compensation to do so.

"With that, there comes a certain level of expectation of the documentation they submit," Schabla said. He also said MISO wants to have confidence that DR resources are real, that ratepayers are paying for actual capacity and that members aren't making decisions to retire generation or forgo adding generation because of fake DR megawatt reductions.

"We feel like we're asking for some very fundamental and basic information," Schabla said. He added that MISO wouldn't outright reject registrations if information is lacking; rather, it would reach out for more data.

MISO also wants every non-residential resource that's registered to submit a physical address of the load's location.

"What we're trying to accomplish here is to figure out where these LMRs are located," Schabla said, adding that the addresses are a starting point.

Beginning in the 2027/28 planning year, MISO said it would further require market participants to submit the elemental pricing nodes for DR resources that are at least 5 MW.

Schabla said MISO hopes to gain more visibility into LMR and eventually be able to order more targeted curtailments in instances like local transmission emergencies. He said the extra year should provide "plenty of runway" for market participants to start assembling more exact location data.

Moving into the 2026/27 auction, MISO will require market participants with DR to submit hourly metered output from every resource in the seasons they're signing up to contribute. The RTO said it would allow single aggregated values from residential DR programs.

Enel X's Allison Miller said time is running out to make registrations for the 2026/27 auction, but MISO has yet to finalize all the new rules and provide all registration templates. She also said there's still a "back and forth" at FERC on MISO's real power testing proposal, which was issued a deficiency letter.

Other stakeholders asked if MISO would hold another workshop to get stakeholders better acquainted with the new rules. Schabla said MISO would not. Schabla said MISO isn't attempting to shut DR out of its markets but needs to discourage bad actors.

"We just want to make sure what we're paying for is quality," Schabla said.

At an Oct. 1 Resource Adequacy Subcommittee, MISO's Neil Shah said MISO understands it's putting market participants through tremendous change with its new DR rules.

LMR Replacement Becomes an Option

There may be a silver lining in the 2026/27 auction: MISO will permit market participants to replace their load-modifying resources if the original resources become unavailable. MISO will allow DR to replace (and avoid penalties for nonperformance) when a contract previously approved by state regulators is terminated or if there's a change in ownership of the facility contracted to dial back load.

For behind-the-meter generation, MISO will allow replacements in the event of outages that are communicated to MISO at least two weeks in advance or if regulatory restrictions crop up, such as environmental run-time limits. MISO also said load-modifying resources can replace on a case-by-case basis with approval from MISO's Independent Market Monitor.

The grid operator said it plans to hold DR resources to more rigid nonperformance penalties and make a FERC filing soon. MISO plans to assess penalties when DR resources are coming up short on what they said they could provide or when a resource is marked as unavailable but is consuming demand during an emergency. Penalties would be based on auction revenue and include a charge based on locational marginal prices at the time.

MISO will divide penalties into either partial failures (when a DR resource has provided at least 25% of its required response) or complete failures (when the resource has supplied less than 25%). MISO said repeat complete failures would lead to disqualification as a capacity resource.

However, MISO said it will offer penalty exemptions for when behind-the-meter generation must perform maintenance. For that, the market participant would have to pre-schedule a no more than 31-day outage in either a spring or fall period (March 1 to May 15, and Sept. 15 to Nov. 30, respectively).

Schabla said MISO realizes it's unrealistic for 30 to 40% of its behind-the-meter fleet to seemingly never need annual outages, as is the case now.

Finally, MISO stressed the importance of market participants updating their availability in its nonpublic Demand Side Resource Interface. Schabla said offers made in the 2027/28 planning will begin to affect DR accreditation in the 2028/29 planning year. Beyond that, MISO didn't touch on the new accreditation, reasoning that it was too early to address it. ■

NYISO Notes 'Fluctuation' of Outlooks for Grid Reliability

ISO Staff: 'On a Knife's Edge with Every Analysis We Do'

By Vincent Gabrielle

The NYISO Operating Committee voted to approve the ISO's *draft* Comprehensive Reliability Plan (CRP), though environmental groups and the Market Monitoring Unit voiced concerns with the wide range of predictions, the lack of identification of needed market changes and the potentially growing disconnect between other planning studies.

An early draft of the CRP, issued Oct. 7, called for "several thousand megawatts of new dispatchable generation by the 2030s," based on a broad range of possible scenarios for load growth and supply. (See *NYISO Reliability Plan Calls for 'New Dispatchable Generation'*.)

The newest draft, which will now go before the Management Committee on Oct. 29, accounts for the third-quarter Short-Term Assessment of Reliability (STAR) and its identification of an immediate reliability need for New York City. (See related story, *NYISO Again Identifies Reliability Need for NYC*.) It was approved over the opposition of the Natural Resources Defense Council.

"The way this is all being presented in this reliability report is going to create great levels of alarm and confusion," NRDC's Chris Casey said at the committee's meeting Oct. 16. "The technical experts understand it's informational, but I don't think it's going to be interpreted that way."

In a newly added sentence to the draft, the ISO acknowledges that, "as demonstrated by the study-by-study fluctuation in the system conditions and associated risks, the NYISO's current approach in evaluating the reliability of the system is no longer sufficient for future planning studies."

Why This Matters

Some stakeholders balked at the breadth of predictions in the CRP, asking for more specificity and clarity on what would trigger a reliability need.

Casey argued that while the CRP talked up the importance of a strong market to meet reliability needs, parts of the report gave the impression that markets will not be able to solve the need. Some of the recommendations would exacerbate the disconnect between reliability studies and the Installed Reserve Margin on which prices are based, he said.

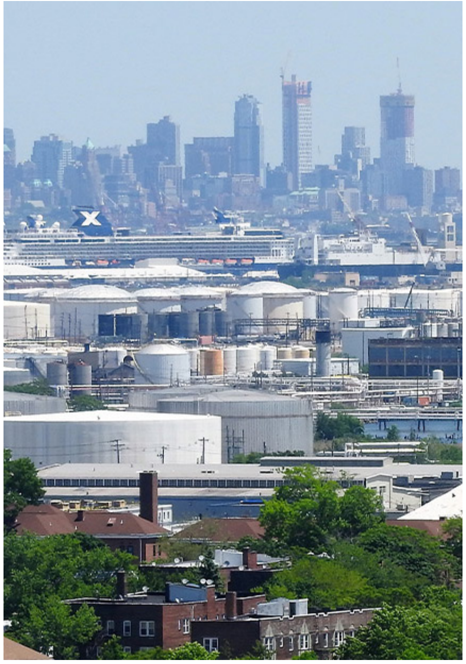
"Your point is really well taken," said Ross Altman, senior manager of reliability planning for NYISO. "We need to discuss with stakeholders which specific range of forecasts or any of these factors we should consider an actionable reliability determination. What we are trying to say strongly is that it shouldn't just be based on one. Combine that with the narrowing margins, and we are on a knife's edge with every analysis we do."

Much of the committee's discussion centered on how to quantify reliability risks on the grid and how this would interact with existing planning processes.

"I definitely share some of the concerns that were shared by previous commenters," said Pallas LeeVanSchaick, vice president at Potomac Economics, the grid operator's MMU. He said that NYISO's analysis acknowledges a broad range of supply and demand outcomes but treats them as "random events."

"The reality is the role of the market is to help moderate excess supply or insufficient supply," LeeVanSchaick said. "The reality is when you look at the risks of aging generation and lack of supply, by far the biggest factors for those outcomes are not the age of the resources but a mix of environmental policies and market incentives for maintaining the generation and repairing significant failures."

Liam Baker, senior vice president of regulatory affairs at Alpha Generation, weighed in as "the owner of the largest aging fleet."



Bayonne Energy Center in Bayonne, N.J. | *Jim Henderson, CC BY-SA-4.0, via Wikimedia Commons*

"When these things break … they break in such a manner that they need to be completely rebuilt," Baker said. "The replacement parts we use nowadays are bespoke. We are … cannibalizing our existing fleet. … We are literally cannibalizing Gowanus 1 and 4 to keep Gowanus 2 and 3 and Narrows 1 and 2 running."

Baker said NYISO was "wise" to highlight aging generation, but he wanted to make sure the ISO and other stakeholders understood how dire the situation was: Replacement parts for the plants often have to be custom made — or even purchased on eBay.

Matt Schwall, director of regulatory affairs for Alpha Generation, said this point was "critical." The retirement dates for Gowanus and Narrows, which drove the reliability needs findings in the Q3 STAR, were not based solely on environmental rules, he said.

"We are proposing to retire these units because they are no longer economic to operate," Schwall said. "There are other things driving generator retirements other than being unable to comply with state regulations." ■

NYISO Again Identifies Reliability Need for NYC

By Vincent Gabrielle

New York City could be short as much as 650 MW in capacity in the summer of 2026, according to NYISO's Short Term Assessment of Reliability (*STAR*) for the third quarter, issued Oct. 13.

The report, which assesses reliability over five years, also identified reliability needs in Long Island and the Lower Hudson Valley, though not until 2027 and 2030, respectively, and both are much less than the city's.

The findings trigger a formal process by which the ISO will seek solutions including transmission, generation, energy efficiency or a combination of each. "NYISO will begin the process immediately by working with the local utilities and the marketplace to identify and evaluate possible solutions," it said in a *press release*.

The shortfall is primarily driven by the impending retirements of the Gowanus and Narrows gas generators in the city, kept online by an ISO designation for reliability under New York state's peaker rule. NYISO continues to say that several projects — including the Champlain Hudson Power Express HVDC transmission line and the Empire Wind offshore wind facility — would solve the city's deficiency. But "until these system plans are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified … deficiencies would persist without Gowanus and Narrows," according to the STAR.

NYISO used its press release to note the findings of its biennial Comprehensive Reliability Plan (CRP), even though it is still being finalized. (See *NYISO Reliability Plan Calls for 'New Dispatchable Generation'*.)

"Taken together, these two reports show the grid is at a significant inflection point," said Zach Smith, senior vice president of system and resource planning for NYISO. "Depending on future demand growth and generator requirements, the system may need several thousand megawatts of new dispatchable generation within the next 10 years."

Gavin Donohue, president of the Independent Power Producers of New York, said residents should be alarmed by the findings.

"Electricity demand is continuing to drastically rise, and the state needs to look at all possible resources to safeguard strict reliability standards that millions of New Yorkers depend on," Donohue said in a statement.

The STAR considers planned retirements, upgrades, forecast peak power demand and changes to the generation mix. Thirty-six gas turbines submitted retirement notices, including the 672-MW Gowanus and Narrows generators.

When the planned transmission and generation projects enter service and assuming all existing generators remain available, reserve margins would improve substantially, but the STAR notes that they would "gradually erode as forecasted demand for electricity grows." As soon as 2029, the city would be once again deficient in the summer, by 68 MW for five hours.

Gowanus barge-mounted natural gas generating station in Brooklyn, N.Y. | *Astoria Generating Company*

"Even with the Champlain Hudson Power Express transmission project online, reliability margins will be breached in the near future due to lack of resources with the same capabilities coming onto the system to replace the planned peaker retirements," Donohue said. "Increasing dispatchable generation must be prioritized so the state does not go dark."

The ISO may extend the operation of Gowanus and Narrows until May 2029 under the peaker rule. They cannot continue operating beyond that date unless they meet state Department of Environmental Conservation emissions requirements.

Long Island could become deficient in summer 2027 by 39 to 116 MW because of the deactivations of the Pinelawn and Far Rockaway generators. Once Sunrise Wind is delivering power, the margins would improve in summer 2028 and again once the Propel NY Energy transmission project comes online in 2030.

NYISO said the Lower Hudson Valley reliability need is an exacerbation of the city's and that solving the latter would solve the former.

But "the risk of deficiencies beyond the needs identified in this STAR is even greater when considering a range of plausible futures with combined risks, such as the statistical likelihood of further generator retirements or failures," the ISO warned. "New York's generation fleet is among the oldest in the country, and as these generators age, they are experiencing more frequent and longer outages."

NYISO's pronouncements echo those of its Reliability Needs Assessment just over a year ago. The ISO narrowly avoided issuing a formal reliability need then, but it made similar warnings of generator aging and retirements, and it also warned that the city's reliability would depend on the Champlain Hudson project. (See *NYISO: Large Load Flexibility Eliminates 2034 Shortfall Concern*.) ■

PJM Stakeholders Present CIFP Options for Meeting Rising Data Center Load

By Devin Leith-Yessian

VALLEY FORGE, Pa. — Several stakeholders presented proposals for how PJM could address accelerating load growth as the Critical Issue Fast Path (CIFP) process on large load growth wraps up its second phase.

Many of the design components revolved around requiring large loads to bring their own generation (BYOG); pathways for fast-tracked interconnection studies for new resources; allocating capacity and interconnection costs to large consumers; and queues to delay them from coming online until there is sufficient capacity to serve them.

PJM updated its proposal at a CIFP meeting Oct. 1, during which Advanced Power, Enchanted Rock and a coalition of generation owners and tech companies presented alternatives. (See *PJM Drops Non-capacity Backed Load, Shifts Focus to Resource Queue, PRD*.)

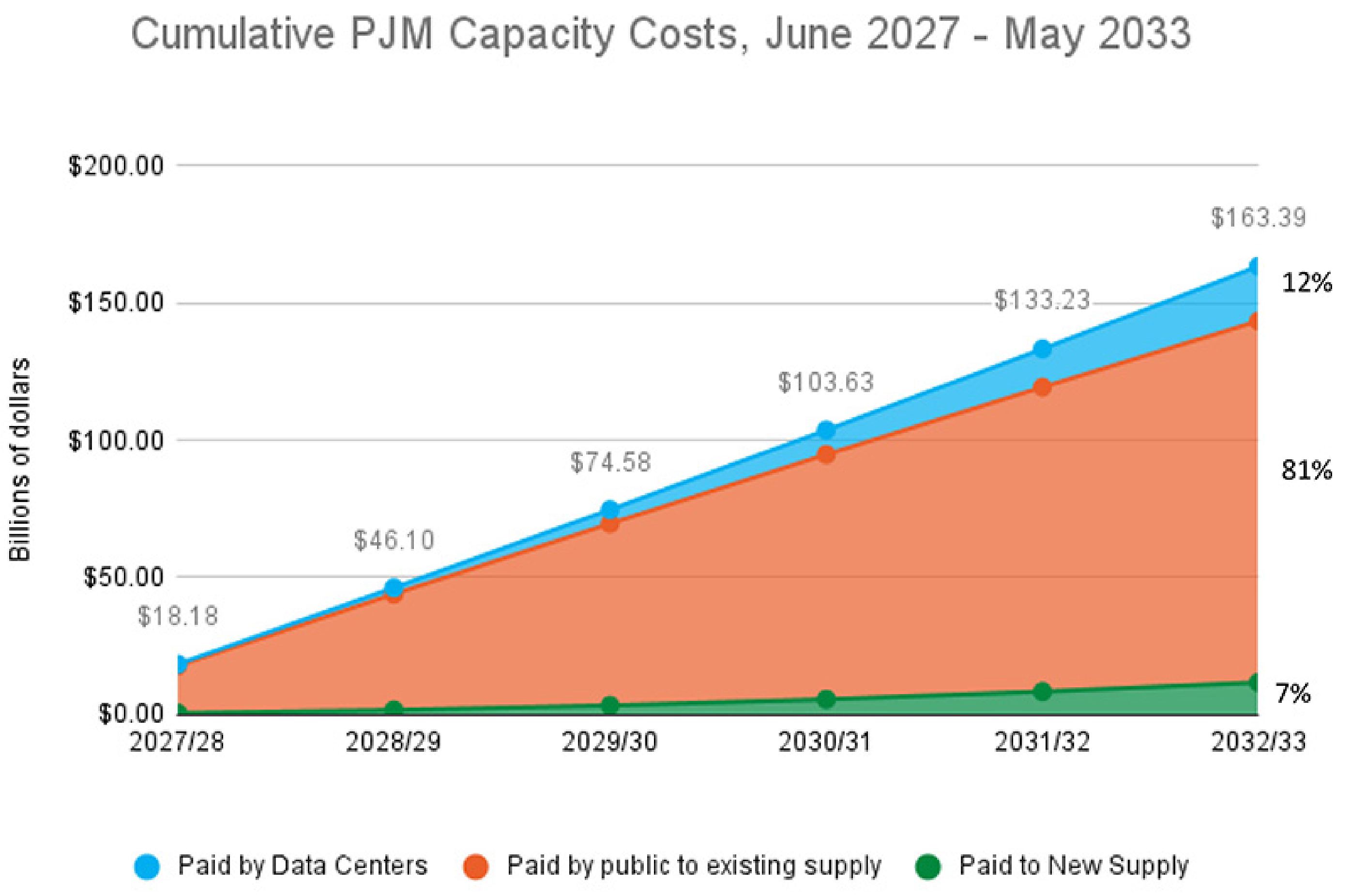
The RTO opened a poll on the proposals following the Oct. 14 meeting to gauge support before moving on to the third phase of the CIFP process, in which the design components will be combined into holistic packages. Manager of Stakeholder Process and Engagement Michele Greening said phase 3 packages should be designed to resolve all issues identified in the Board of Managers' *letter* initiating the CIFP. The first of the phase 3 meetings is scheduled for Oct. 24.

Eolian BIGPAL Proposal

The bilateral integration of generation portfolios and load (BIGPAL) *proposal* from Eolian would allow planned large loads to procure their capacity from adjacent resources coming online at the same time.

The resources would qualify for a 90-day interconnection study process and not participate in the capacity market; be assigned capacity interconnection rights (CIRs); or be derated by PJM's effective load-carrying capability accreditation framework.

While the proposal's definition of "adjacent" is not yet set, Eolian said siting the resource electrically near the load would reduce the need for transmission upgrades and allow it to perform under emergency conditions. While a performance assessment interval (PAI) is active, the BIGPAL configuration would be required to reduce its net load to zero. Load flexibility would serve as a backstop to resource performance.



The NRDC projected the amount consumers would pay for capacity if the imbalance between data center growth and capacity construction continues to grow. | *NRDC*

The risk of the resource underperforming during a PAI would be shared by the parties to the contract, with penalties if there is a net draw off the grid.

The adjacent resource would be able to participate in PJM's energy market and would be available to security-constrained economic dispatch. Brattle Group consultant Andrew Levitt, who helped prepare the proposal, said it would make sense for BIGPAL resources to operate as normal PJM resources when PAI risk is low and prioritize being available to serve the adjacent load when an emergency appears likely.

Brattle modeled how BIGPAL would perform in the 2030 delivery year, using PJM's load and expected resource mix and two RTO scenarios: 6 GW of new unforced capacity and 8 GW of retirements, and 12 GW of new capacity and no deactivations. The firm developed a moderate weather scenario built off 2018 and a more severe weather year based on 2022. The model assumed 25 GW of BIGPAL load paired with 20 GW of storage and 5 GW of gas generation.

The analysis found there would be no load shed in a moderate weather year in the scenario where deactivations outpace new entry and 16 hours of load shed in a severe weather year.

Bruce Campbell, principal of Campbell Energy Advisors, said he is concerned about any proposals that would create new forms of curtailable load that would be dispatched after demand response customers. Coming out of a summer with a high amount of pre-emergency load management deployments, he said participant fatigue may be a concern going forward with the prospect of substantially more dispatch as reserves shrink. He noted that "fatigue" can mean simply that customers are losing money with each hour of dispatch.

Glatz and Silverman Present Alternative NCBL Design

Abraham Silverman, research scholar at Johns Hopkins University, and Suzanne Glatz, principal of Glatz Energy Consulting, *presented* several design components intended to minimize the impact large loads would have on existing consumers.

They proposed a bifurcated capacity market in which the first round of the auction would set a clearing price for native and non-large load, followed by a second round clearing large loads and any generation that had not already cleared. The price for the second round of the auction would be inclusive of make-whole payments for resources that cleared in the first round, ensuring that all resources receive the same capacity price.

> **Notable Quote**
>
> "Allowing the interconnection of large new data center loads without matching capacity imposes costs and risks on all other customers, increasing prices and the risk of blackouts for other customers. That is not consistent with PJM's stated objective of putting reliability first."
>
> *– PJM Monitor Joe Bowring*

Building on PJM's mandatory non-capacity backed load (NCBL) proposal, they recommended a variant that would subject large loads to curtailment in delivery years when the capacity market cleared above the midpoint on the variable resource requirement curve. Curtailments would fall ahead of all DR customers in the stack of emergency procedures. While mandatory NCBL is no longer PJM's preferred solution, it remains a design component stakeholders can include in their packages.

Load-serving entities would be able to avoid being assigned NCBL allocations by ensuring that large loads can offset 80% of their peak load for at least four hours 10 times a year. Glatz said this would create an incentive to participate in BYOG models.

NCBL load would be required to pay half of the capacity clearing price each delivery year to capture the benefits it receives from non-firm service when there are no curtailments.

The initiation of the CIFP process would be considered the cutoff point for any NCBL requirement, with existing load exempt.

Another component would exclude large loads from PJM's forecast unless the relevant utility attests that all distribution and transmission upgrades needed to interconnect the load will be complete before the delivery year; the large load attests that it is not planning similar new service requests that might result in the project being canceled or modified; and the customer provides evidence of commercial maturity, such as "take-or-pay" agreements for transmission service. If an NCBL model similar to PJM's initial proposal were to be implemented, participating large loads would also be excluded from the forecast.

NRDC Supportive of NCBL

The Natural Resources Defense Council *recommended* an NCBL construct in which large loads would not receive firm service unless they were paired with new capacity or resources that did not clear in the capacity market.

Large loads could gain firm service by committing to participate in DR or price-responsive demand programs, or contracting with other consumers to participate on their behalf.

The proposal aims to recognize the jurisdictional questions around PJM defining particular consumers as being subject to NCBL and leaving implementation to the states. The RTO would determine the amount of NCBL needed across its footprint and distribute that figure across locational deliverability areas (LDAs); from there, states and utilities would determine how to assign that to customers.

The proposal would designate curtailment as either the final energy emergency alert level 1 action or the initiator for level 2. This would lead to it being instituted either prior to or concurrent with the start of scarcity pricing.

Few planned resources expected to come online in time to participate in the 2026/27 Base Residual Auction (BRA) have submitted offers, which is creating a false tightening in the market, according to the NRDC. Reducing the risk of participation could mitigate that, including by PJM making a commitment that it will not seek to reinstate the minimum offer price rule in place before 2018. (See *3rd Circuit Rejects Challenges to PJM MOPR, Affirms Authority over FERC Deadlocks*.)

The NRDC conducted analysis on the

cost of the load growth and reliability gap that PJM is projecting, finding that consumers would pay $163 billion in capacity costs between the 2027/28 and 2032/33 BRAs. Data centers would pay a small amount of those increased capacity costs, and most of the revenue would flow to existing supply, which the NRDC found would create a scenario where 81% of the $163 billion are "deadweight" payments that existing consumers pay to existing supply.

Monitor Recommends Load Interconnection Queue

The Independent Market Monitor *proposed* creating an interconnection queue for large new data center loads in which they would be interconnected only when any required transmission upgrades are complete and there is enough capacity and energy to serve them reliably.

Large loads would be eligible to bypass the queue via an expedited interconnection process if the loads brought new generation (BYONG). The new generation would have to be deliverable to the grid, deliverable to the new load, and capable of matching the amount of time the load will be online. Monitor Joe Bowring gave the example of intermittent resources combined with storage, or thermal generation, both qualifying for the duration component.

Participation in DR would not fall under the BYONG model, as Bowring argued it does not match the duration of the load and is not equivalent to bringing new generation capacity online.

Bowring said the proposals to treat large new data center loads as on the demand side would have them interrupted only after existing demand-side resources are interrupted and only if there is a reliability emergency. That treatment would impose significantly increased interruptions on existing demand-side customers and risks those customers leaving the program, he argued. It would also increase the occurrence of scarcity pricing in the energy market, which imposes higher energy costs on all customers.

"Demand side is not generation," Bowring said in an email to RTO Insider. "If the large new data center loads are going to enter without capacity, they should be interrupted whenever existing capacity is needed by the customers that pay for it."

Bowring said if PJM is not capable of serving a new load, the RTO should not be obligated to allow it to interconnect. He said the premise of all the other CIFP proposals is that PJM must interconnect large new data center loads when there is not enough capacity to serve them reliably.

"That premise is not correct," he said. "Allowing the interconnection of large new data center loads without matching capacity imposes costs and risks on all other customers, increasing prices and the risk of blackouts for other customers. That is not consistent with PJM's stated objective of putting reliability first."

It also increases the demand for energy without increasing the supply of energy, increasing energy costs for all customers by an estimated $2 billion to $3 billion per year, Bowring said.

Pointing to *Part A* of the Monitor's report on the 2026/27 BRA, Bowring said data center load growth has caused capacity costs to increase by $16.6 billion over just the last two auctions — costs that should not be shifted to existing consumers, he said.

Vistra Seeks Penalties for Utilities Short on Capacity

Vistra *proposed* instituting penalties for utilities that do not cover their own capacity needs with the aim of incentivizing bilateral contracts that take strain off the capacity market.

The proposal includes variants for triggering penalties if the load forecast for a capacity auction signals it may be tight, during emergency procedures or a combination. Assessing the penalties in advance carries the advantage of providing more incentive to get contracts in place before the auction, while implementing them during emergencies creates more flexibility on the amount of risk a utility is willing to accept. Several penalty rates were also presented for each option.

Operational penalties would create incentives for utilities to offer load flexibility products to customers to mitigate the risk that the utility might not have enough capacity in place, while planning-based penalties would create more incentives to contract with DR providers.

EKPC Recommends Requirements for Self-supply

The East Kentucky Power Cooperative *proposed* "significant" penalties for LSEs that enter a BRA without enough owned or contracted supply to cover its capacity obligation. The penalties would be assessed against all deficient LSEs within an LDA if an auction does not procure enough supply for that zone.

Large loads would be required to identify the LSE that will serve them before they are included in the load forecast as a large load adjustment (LLA), which feeds into the amount of load to be served in a given BRA; if an LSE is not identified, it could be treated as being served by the default provider. That is intended to serve as a "reality check" that the load is likely to come into service in that delivery year and reduce duplicative LLA requests. State involvement in the load forecasting process could further advance the reality check. Large loads would be defined as a site with load exceeding 50 MW.

The penalties would be distributed to LSEs that had procured enough capacity for that delivery year as compensation for the price pressure and load shed risk they faced. State regulators would be encouraged to create retail rate structures that allocate penalties to large loads and reduce the impact on existing consumers.

NOVEC Proposes Changes to NCBL

NOVEC proposed modifications to PJM's NCBL proposal that would remove the load from the capacity market and place its curtailment as the penultimate step in the RTO's emergency procedures, after all other DR products and just before load shed.

If an EDC or LSE cannot assign enough NCBL to meet PJM's allocation for its region, it would be assessed a daily deficiency penalty for the amount it is short, which would be refunded to other utilities. If NCBL load does not curtail, it could be subject to FERC and NERC compliance and financial penalties.

NOVEC's Rory D. Sweeney said that if NCBL is to be implemented, it should be structured as a permanent late-stage emergency procedure.

Md. OPC Focuses on Load Forecast and BYOC

The Maryland Office of People's Counsel *recommended* changes to PJM's load forecast process, a bring your own capacity (BYOC) model, a large load-specific DR product and assigning more load shed obligation to regions with large loads not backed by new capacity.

The proposal would have PJM develop scenarios accounting for the uncertainty around LLAs coming online when it develops its load forecast, with the modeling tied to the advanced nature of the capacity market and Regional Transmission Expansion Plan (RTEP). The amount of load included in the forecast for each utility could be reduced if they do not establish a tariff for large loads or a dedicated oversight process for their interconnection that includes project milestones and financial commitments.

The BYOC element requires new large loads to either bring enough capacity to meet their own needs or offer the equivalent of their peak load into a load-offset demand response (LODR) product — a temporary program designed for large loads to net to zero either by curtailing or activating behind-the-meter generation. The capacity would have to be deliverable to the load and come online at the same time.

Mainspring Seeks Changes to EIT

Mainspring Energy *presented* several changes to PJM's proposals, including shifting the focus of its expedited interconnection track (EIT) to prioritize resources that can be built quickly, rather than prioritizing the size.

The EIT model presented on Oct. 1 would create a 10-month interconnection study process for projects at least 500 MW and capable of being in service within three years.

The revised eligibility requirements would allow projects above 50 MW to participate, including projects to uprate or repower existing generation. It would also make state sponsorship of projects voluntary, removing a requirement PJM said was intended to reduce the risk that a project would be expedited through its queue only to become mired in state siting and permitting processes.

Director of Wholesale Market Development Brian Kauffman said the majority of data centers are on the scale of 50 MW and could be served by comparably sized resources.

It also recommended that PJM include a voluntary NCBL model in its package and for states to develop non-firm or flexible service models for retail load. Kauffman said speed-to-market is the priority for data center developers, who might be willing to accept less firm service in exchange for faster interconnection.

Pa. and Va. Governors Offer Perspectives

Presenting on behalf of Pennsylvania Gov. Josh Shapiro and Virginia Gov. Glenn Youngkin, Pennsylvania Deputy Secretary of Policy Jacob Finkel overviewed their perspective that efforts to streamline the entry of new supply and minimize the impact to residential and commercial ratepayers should be prioritized.

Models that offer a carrot rather than a stick are preferred, particularly those with voluntary short-term flexibility paired with incentives for long-term resource development, Finkel said.

The governors support Eolian's BIGPAL proposal as a way of reducing delays in getting generation built, though more market design changes would be needed to ensure proper incentives are in place, Finkel said. Load forecast changes would also be welcome, but he noted that would not change the supply and demand challenges PJM faces. ■

NCUC Examines the Challenges of Meeting Demand from Large Loads

By James Downing

The North Carolina Utilities Commission held hearings over several days examining how utilities in the state are planning for large loads including data centers — not just how to serve them reliably but also adapt to the changes they are bringing to the industry.

"We are experiencing a lot of growth in the Carolinas, and that is not restricted just to large loads; it's across residential, commercial, industrial and manufacturing sectors," Jonathan Byrd, managing director of rate design for Duke Energy, told the commission Oct. 15. "And that said, we certainly acknowledge that these large loads present unique challenges and opportunities. The growth we're seeing reflects the state's favorable business environment, which includes constructive energy policies and affordable and reliable electricity."

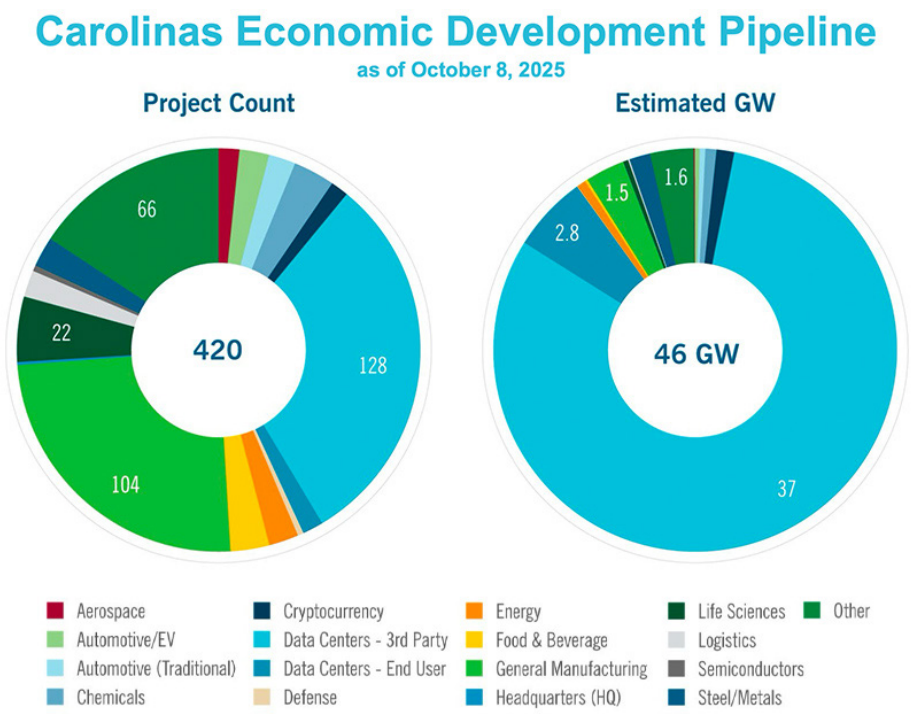
Duke has been updating its rules as the new load paradigm has become apparent, and that fine-tuning is going to continue as it gains experience serving new customers, he added.

The utility, which serves most of the state, has received inquiries from 420 projects totaling 46 GW in total possible demand for economic development. Of those projects, 128 are data centers representing 37 GW of demand, said Andrew Tate, Duke's managing director of economic development.

"We acknowledge that only a fraction of these will ever progress to actually receive service," Tate said. "We receive new project inquiries every week, and every week we have projects that advance to either terminate or loss, or successful outcome."

Large load projects can be a challenge for utility planners, but they bring major economic benefits, including jobs and tax revenues for communities that sometimes have been overlooked in past economic expansions, he added.

"The large load customers that we work with daily value certainty in generation resources, as opposed to the uncertainty that can exist in some markets when it's uncertain who's building the generation," Tate said. "Our customers expect us to provide the load to serve their needs."



A chart Duke Energy presented showing the total amount of inquiries and related demand it has received from potential large load customers | *Duke Energy*

Why This Matters

North Carolina has had demand growth for years, but a wave of new large load customers is on the way that will speed up growth significantly.

While on-site backup generation is common, Duke has seen relatively few large load customers interested in co-location, and that usually relates to speed-to-market concerns when they want to locate in an area with transmission constraints, he added.

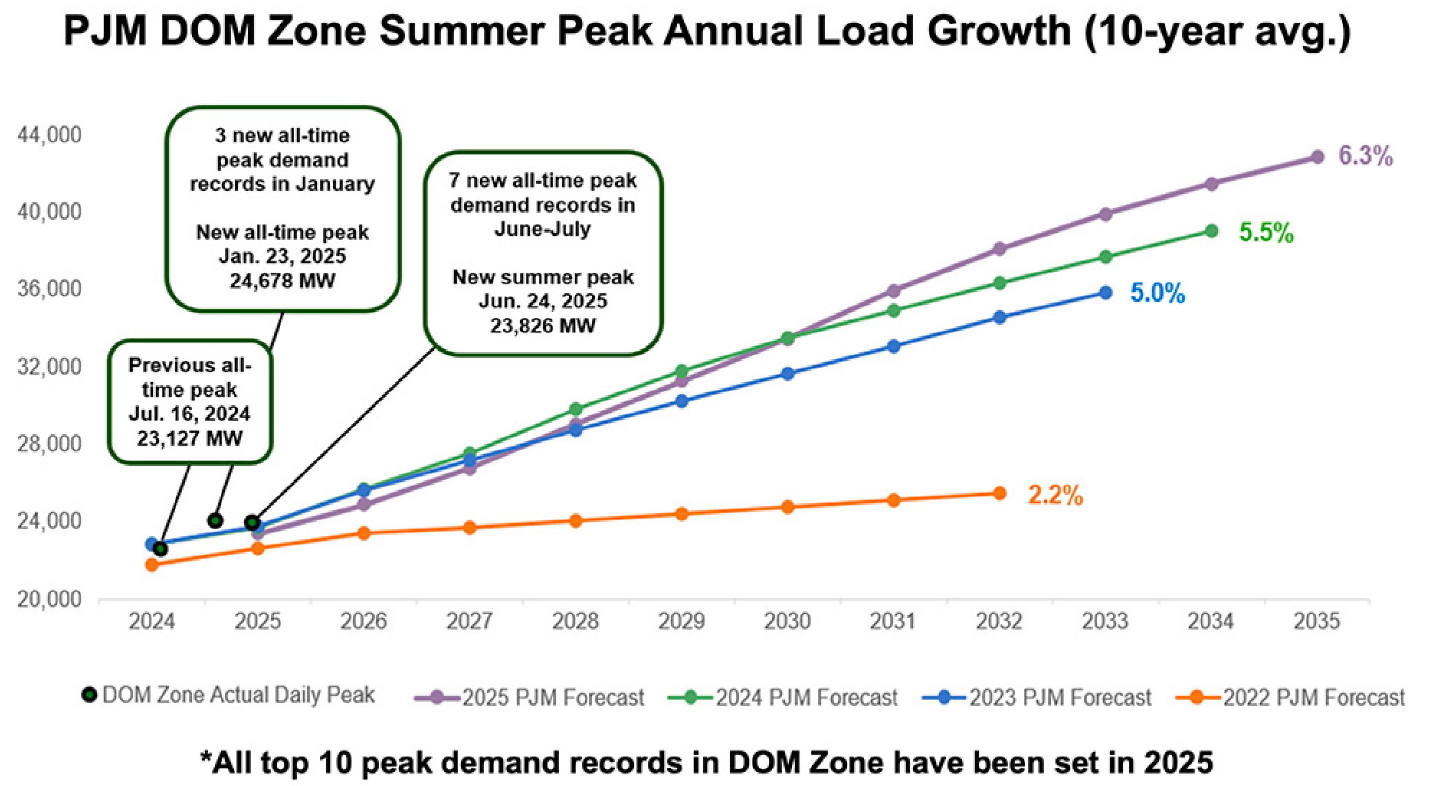
Duke has arrangements with the new large load customers that are designed to hold existing customers harmless while helping the sites get online in the name of economic development, said Alex Castle, the utility's deputy general counsel.

"Protecting existing customers remains our central priority, but we're always conscious of the balance that's required to ensure that the risks and accountability that we're asking new large load customers to carry are reasonable," Castle said. "We intend to check and adjust over time in order to refine our approach to right-size these financial and operational requirements."

Duke starts by studying the project's impact on its grid and resource adequacy, which are laid out in a "letter agreement" that the prospective load has 30 days to sign once issued. That signals an intent to proceed and comes with preliminary financial commitments. That is followed by an electric service agreement (ESA) that must be signed within 120 days and lays out the long-term conditions for service, Castle said.

Dominion's Experience with Data Center Alley

The NCUC also heard testimony from Dominion Energy, which has long-term experience with data centers, as its Virginia utility serves the largest market for



A chart Dominion showed laying out the growth in demand forecasts in recent years and recent peak demand days | *Dominion Energy*

them in the world.

Data centers make up 25% of the utility's total demand, which is expected to rise to 50% in 2035, said Vice President of Regulatory Affairs Scott Gaskill.

Dominion has set up an internal "Data Center Practice" to help manage its service of the key customer group, said its director, Stan Blackwell.

"If you add up the next five large U.S. markets — add them together — they're not as big as our Virginia market," Blackwell said. "In fact, it's [just] Loudoun County. It's about 30 square miles. It's the largest market in the world."

Just seven customers make up 72% of that market, and Dominion is able to base its forecast around their future growth individually, while putting the other 28% in an eighth category for forecasting. The main market in Loudoun runs an average of about a 90% capacity factor, and curtail-ability of that load is limited. It serves as a constant baseline of demand while small customers drive the peaks, Blackwell said.

Dominion is seeing data centers expand beyond Loudoun, which is the wealthiest county per capita in the nation with expensive land. The new wave of data centers built to train artificial intelligence is leading to more sites being located in cheaper areas of Virginia.

"In AI, there's kind of two modes of it, if you will," Blackwell said. "One is, you train a model. So, your data center cycles up and down to train a model. Once it's trained, you take it out of that [and] put it in what's called an inference data center, and that's the one that runs like a chainsaw. So, once you have a model train, it runs all the time. You don't tend to want to curtail that, because that's what customers access."

The utility has so much experience with data centers that it is able to build statistical models based on past experience to forecast future demand from the sector.

"We do it statistically by our largest customers and look at their past behavior and then make an assessment whether that will continue in the future," Blackwell said. "And we haven't seen a change in the behavior over the whole time period: 2013 to today."

Dominion has a pending proposal at the Virginia State Corporation Commission to set up a new large load tariff that will separate out the customer class, offering data centers and others transparency while ensuring fair cost allocation going forward, Blackwell said. (See *Citing Inflation and Load Growth, Dominion Asks Virginia for Higher Rates*.)

Are Large Load Tariffs Necessary?

Neither Dominion nor Duke were in favor of setting up similar large load tariffs for North Carolina, but NCUC public staff urged commissioners to get ahead of the issue and start working on constructs for both companies now.

The suggestion comes after staff reviewed 44 tariffs from 28 states, said Dustin Metz, NCUC engineer for public staff.

"Large load has driven electric system growth, but with fewer larger customers than in the past, high-load-factor customers have unique operating characteristics and occupy a different role than traditional large general service or traditional industrial customers," Metz said. "With careful rate design, reasonable ratepayer protections will allow parties to prosper, support economic development and ensure risks are mitigated."

Even if large customers do everything right, they still face economic risks that could lead to their early retirement, which risks stranded costs falling to others, said Patrick Fahey, public utilities regulatory analyst for the North Carolina Department of Commerce.

Commissioner Karen Kemerait noted that the utilities do not want specific large load tariffs in North Carolina, arguing their current rate structures are able to fairly allocate costs for any new load, and asked staff members for their response.

"If we decide to do nothing in terms of a new tariff in the next three years, the large load is already going to be here," Metz said. "They're going to be under a different tariff design."

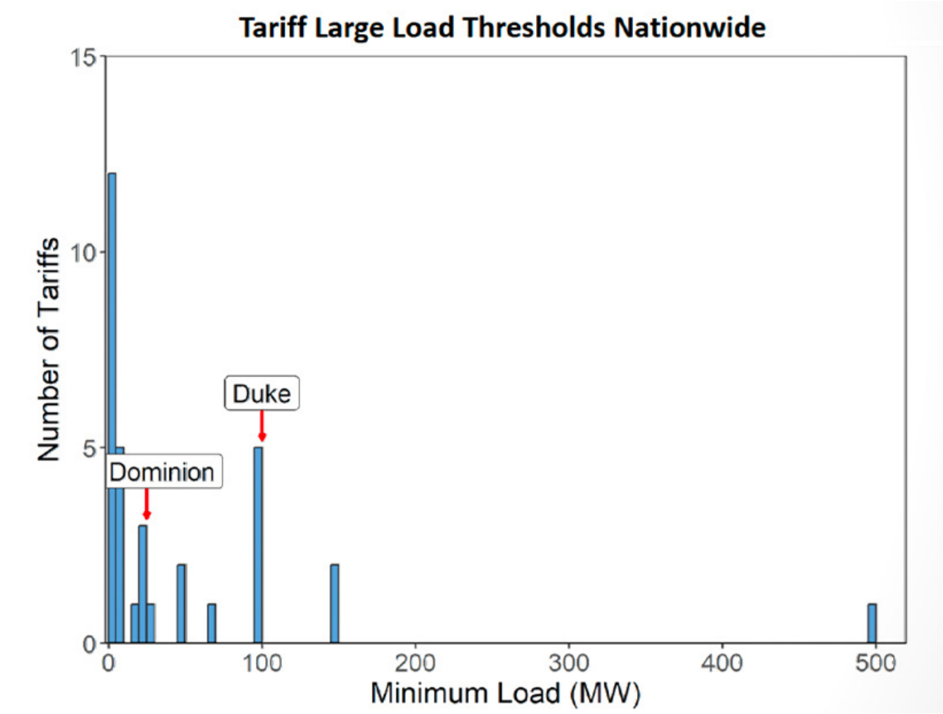
Staff want the commission to start working on large load tariffs now so that they are already in place once the new loads start to make a major impact on North Carolina, he added.

"There is this variability in load forecasting that others have touched on — who will and won't show up — and how that will change even in a relatively short time period means that the earlier we can get ahead of this and establish something that helps set guidelines as to what the large load customers can come in to expect," Fahey said. "And that gets into potential improvements in forecasting and a better understanding from that customer's perspective, especially if they're cross-shopping against different states."

Lucas Fykes, policy director of the Data Center Coalition, said in testimony Oct. 14 that his group has been involved in the development of large load tariffs around the country, and many start to kick in for customers with demands of 50 to 100 MW, though on the lower end that can start to impact major industrial sites – not just data centers. The main issue is that no group of customers is singled out and that cost allocations are also fair to the large loads, he said.

"Certainty is very important for planning and operational purposes," Fykes said. "We are leaning in as an organization, and many of our members are individually leaning in, in support of taking traditional terms that were usually in ESAs and putting those into tariff requirements that are fair and equitable."

Large load tariffs vary by utility and states because the facts on the ground are



NCUC Public Staff's chart showing the megawatts of demand where different states' large load tariffs kick in | *NCUC Public Staff*

different, but Daymark Energy Advisors consultant Jeffrey Bower (a witness for the Environmental Defense Fund) said that some best practices have become apparent. Certainty is important for customers and utilities.

"Customers don't want to invest unless they are clear about what their obligations are long term," Bower said. "Utilities don't want to invest in new infrastructure unless they're clear that the customers are going to be there and are going to be contributing meaningfully to the cost of that infrastructure."

Contract terms need to be shared with prospective customers early in the process, and defined rate classes that acknowledge their specific needs are important for certainty. Termination fees are another important part of the toolkit.

"The next principle, which has been discussed a bit, is the equitable cost allocation," Bower said. "And so that's a fundamental principle around cost causation and allocation, which protects existing customers, creates fair rates for new customers and aligns the incentives for efficient utilization of grid resources."

AEP Ohio's new large load tariff has already had a major impact on the pipeline of large loads looking to connect to its system. (See *PUCO: Data Centers Must Guarantee Power Purchases from AEP Ohio*.)

"Just last week, AEP *announced* that since enacting the tariff, its pipeline of data centers had fallen from 30 GW down to 13 GW," Bower said. "And so, this is clearly a big impact of the tariff design. It's up for debate whether this drop signifies a reduction in economic development, or if it's a decrease in speculative interconnection requests."

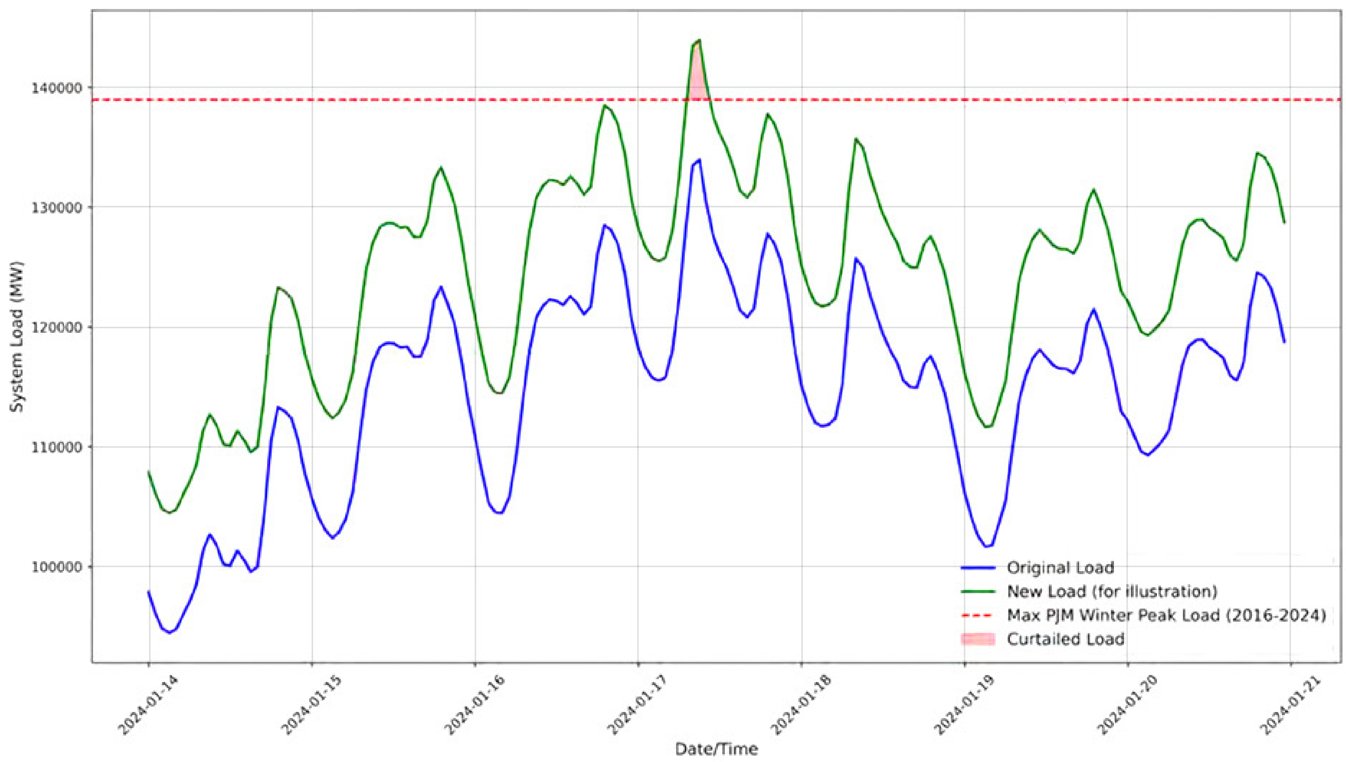
The Role of Flexibility in Meeting Demand

With speed to market and the industry's ability to meet demand that is projected to grow faster than new, firm capacity can come online, demand flexibility from data centers has been discussed as a way to square that circle.

Duke University fellow Tyler Norris, who authored a widely cited paper on the subject, testified at the NCUC's technical conference. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

"Our goals for this were to support regulators and stakeholders in identifying strategies and tactics to accommodate this load growth without compromising the reliability, affordability or progress on decarbonization," Norris said.

The study is based on examining the 22 largest balancing authorities in the



An example from the Duke University data center report showing how little demand flexibility is needed to unlock spare capacity | *Duke University*

country, which account for 95% of its total demand for electricity.

"Current expectations are that AI-specialized data centers will represent the single largest share of U.S. electricity load growth over the next five to seven years, and could represent up to 44% through 2028 alone," Norris said.

Coupled with the need to maintain reserve margins, the highest forecasts indicate national peak load growth of 180 GW by 2030 alone. Norris said that could easily rise from 700 GW today to 850 GW in the next decade, which would exceed the supply chains for new gas turbines.

"We don't know exactly how many turbines will be available," he added. "The current estimate suggests 60 to 80 GW by 2030. Mitsubishi says that they are ramping up production."

Battery storage can help; solar is still economical; and eventually small modular reactors or other new technologies will become available.

"We're going to have to get creative with other solutions," Norris said. "And so that's why, for us, there's an emphasis here on bringing the demand side into the equation more, so that we can utilize the existing grid that we've already paid for."

In the Southeast, the bulk power system has an average and median load factor of about 53%, and it is only stretched to the limit on the coldest winter mornings and late afternoons on the hottest days of summer.

"We're talking in the range of 50 to 200 hours per year that we're building the system out to," Norris said.

His study found that just 1% of demand flexibility from data centers could unlock 126 GW of capacity around the country; 0.5% could unlock 98 GW; and 0.25% for 76 GW. Duke's system in North Carolina could add 4.1 GW of new demand with 0.5% flexibility from data centers.

Data centers can achieve flexibility through on-site resources such as batteries or backup generation, shifting computing load to other facilities in regions not impacted by peak demands, or curtailing their activity in response to price signals.

NCUC Chair William Brawley asked whether computing would shift offshore if that policy were adopted nationally.

"There could be the possibility, perhaps, on the non-national security things, where that might actually be somewhere in Asia. Is that not a potential unintended consequence of this policy?" he asked.

That kind of spatial flexibility is an advanced capability for the tech firms building out data centers, and it has not been tested at scale, Norris said.

"It may be worth noting that it's the policy of this administration to encourage data center development abroad, including in the Middle East, and there's been major deals announced in terms of chip sales and exports of U.S.-manufactured gas turbines to the Saudis to support data center development there," he added.

Norris said he is a big believer that winning the "AI race" is important and leveraging grid flexibility here could help.

"We can't build infrastructure as fast as the Chinese, and so I view this kind of system optimization and using technology to get more out of the grid we already have, or whatever we're building towards, is actually a critical source of national competitiveness because we're just going to have constraints on how much we can build very quickly," Norris said. ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Oct. 23. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

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

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

The committee will be asked to endorse as part of its consent agenda:

B. proposed *revisions* to Manual 3A: Energy Management System Model Updates and Quality Assurance drafted through periodic review of the document. The proposed language reflects the sunsetting of the Data Management Subcommittee and its replacement with the Modeling Users Forum, which was intended to allow for a long-term perspective. (See "Stakeholders Endorse Manual Revisions Reflecting Creation of Modeling Users Forum," *PJM OC Briefs: Oct. 8, 2025*.)

Endorsements (9:10-10:10)

1. Wind and Solar Resource Dispatch in Real-time Market Clearing Engines (9:10-9:30)

PJM's Vijay Shah will *present* a proposal to rework how wind and solar resources are dispatched in the real-time energy market. It would establish an Effective EcoMax parameter meant to more accurately capture how renewable resources are forecast to operate. It would also limit their ramping to 20% of their installed capacity per minute to reduce system volatility. (See "Renewable Dispatch Proposal Endorsed," *PJM MIC Briefs: Aug. 6, 2025*.)

The committee will be asked to endorse the proposal and corresponding revisions to the tariff and Operating Agreement.

Issue Tracking: *Wind and Solar Resource Dispatch in Real-time Market Clearing Engines*

2. Resource Scheduling Prior to the Day-ahead Energy Market (9:30-9:50)

PJM's Phil D'Antonio will *present* tariff and OA language to implement the offer capping of resources scheduled in advance of the day-ahead energy market by committing them on their cost-based offers. The proposal was approved by the Market Implementation Committee during its Sept. 10 meeting with the intention of subsequently developing governing document language.

The committee will be asked to endorse both the proposal and the corresponding tariff and OA language. PJM would seek same-day endorsement by the MC if approved by the MRC.

Issue Tracking: *Resource Scheduling Prior to the Day Ahead Energy Market*

3. Manual 14D Revisions (9:50-10:10)

PJM's Michael Herman will *present* proposed revisions to Manual 14D: Generation Operational Requirements to codify FERC-approved requirements for resource owners seeking to deactivate their units (*ER25-1501*). If the resource intends to participate in capacity auctions, it must provide at least a year's notice ahead of its desired deactivation, while those not participating would follow the must-offer exception process. The changes would also revise elements of the deactivation avoidable cost credit and increase the number of documents that would be publicly posted. (See "1st Read on Manual Revisions Detailing Generation Deactivation Process," *PJM OC Briefs: July 10, 2025*.)

The committee will be asked to endorse the proposed manual revisions.

Issue Tracking: *Enhancements to Deactivation Rules*

Members Committee

Consent Agenda (11:05-11:10)

The committee will be asked to endorse as part of its consent agenda:

B. proposed *revisions* to the tariff and OA to allow demand response resources to offer regulation-only service at sites where energy may be injected onto the grid, so long as the arrangement is reflected in a net energy metering agreement with their electric distribution company. (See "PJM Reviews Proposal on Regulation Resources at NEM Sites," *PJM MRC/MC Briefs: Aug. 20, 2025*.)

Issue Tracking: *DER Regulation Market Only Participation at NEM Customer Sites*

Endorsements (11:10-11:30)

1. Resource Scheduling Prior to the Day-ahead Energy Market (11:10-11:30)

If endorsed by the MRC, D'Antonio will review the offer capping proposal for a same-day endorsement at the MC. ■

— Devin Leith-Yessian

SPP Stakeholders Trim $2.5B from 2025 Transmission Plan

By Tom Kleckner

LITTLE ROCK, Ark. — It took six votes during more than four hours of discussion — over the course of two days of meetings — before SPP stakeholders endorsed the 2025 10-year transmission plan and some of its proposed 765-kV lines, trimming about $2.5 billion in costs from the portfolio.

Members of the Markets and Operations Policy Committee on Oct. 13 first rejected their own proposal to defer the three southern legs of a proposed 765-kV overlay that would have shaved $3.83 billion in costs off the portfolio. They then shot down a motion to endorse the plan and the assessment report as modified by two stakeholder groups.

Neither motion received more than 57.5% approval, far short of MOPC's 66.7% threshold.

After a night's rest, SPP staff regrouped Oct. 14 during MOPC's second day with three new proposals. They asked members to endorse:

- the 2025 Integrated Transmission Planning assessment report as having been completed according to the tariff;
- construction permits for the report's 345-kV projects and three 765-kV reliability projects on the eastern and western legs of the RTO's southern extra-high-voltage overlay; and
- permits for the three 765-kV economic projects looping the overlay's two legs together. The Crawfish Draw-Minco-Seminole-Anthem segments total about 515 miles and are estimated to cost $3.83 billion.

Referring the previous days' voting "failures," Casey Cathey, SPP vice president of engineering, asked MOPC for a "more clear and granular" direction for the Board of Directors to better prepare it for its consideration of the ITP when it meets in November.

Staff have been studying about $18 billion in transmission projects as part of the 2025 assessment. The grid operator has proposed deferring $7 billion in 765-kV projects, reducing the portfolio to $11.16 billion for up to 50 construction permits to meet reliability and short-term needs. It has projected benefit-cost ratios of between 10:1 and 15:1. (See *SPP Wants to Defer $7B in 765-kV Projects to 2026*.)

Why This Matters

SPP stakeholders have trimmed about $2.5 billion in costs from SPP's 10-year transmission plan, reducing the portfolio to $8.7 billion. That's still a record, but it defers about $10 billion to the next ITP assessment and could complicate the planning.

Cathey reiterated the RTO's cost-control measures and outlined several recent and in-flight tariff changes that improve the SPP's cost-estimate process. He said the 2025 ITP's 765-kV economic projects will have additional control measures and conditions, including alignment with the 2026 ITP 765-kV overlay.

The grid operator was stung recently when cost estimates for its first 765 project, Southwest Public Service's 345-mile Potter-Crossroads-Phantom transmission line that was part of the 2024 ITP, more than doubled from $1.69 billion to $3.62 billion. It took several additional months of meetings for SPP to secure the project's approval after SPS staff refined the RTO's project projections. (See *SPP Board Approves 765-kV Project's Increased Cost*.)

"We just went through that with the Potter-to-Crossroads-to-Phantom facility, so everybody has kind of a clear understanding of how that might work," Cathey said, calling it a "good example" of SPP's existing cost-control measures. "That project obviously came in higher for a number of reasons, but it also helped from benefits, cost-ratio and reliability needs perspective."

MOPC members provided the "granular" feedback with their concerns on affordability, cost allocations, inequitable benefits and uncertainty about moving too fast or whether load growth slows. They questioned staff about the lack of analysis in the two motions to approve transmission projects and raised concerns about reliability concerns when 765-kV projects are set aside.

NextEra Energy Resources' Jeff Wells objected to voting on separate construction permits rather than the entire portfolio.

"It was designed as a whole. It was studied as a whole, a complete portfolio. It works in concert," he said. "Piecemealing it apart, simply because maybe we don't like the designation, potentially, of reliability or economic [projects] … when you piecemeal that, you run the risk of losing the benefit that the portfolio has as a whole."

"SPP has a really tremendous opportunity for growth with the industrial and technological developments that we're seeing in this country; load growth as a result is also predicted to be tremendous," said Jennifer Solomon, also with NextEra. "If we don't build this portfolio as a whole, the development may not come, because what we're seeing is that there may not be room for it. MISO, ERCOT and PJM are all moving aggressively forward with 765-kV lines just to keep up with the loads that they're seeing."

MOPC easily endorsed the first two motions. However, the motion to endorse the three 765-kV economic lines fell woefully short at 43.8% approval.

As staff mulled next steps, Director Steve Wright weighed in. He pushed for compromise among stakeholders and called for a better understanding of mitigating risks with large transmission facilities.

"One of the things that's been ingrained in me in the three years on the board is it's a hallmark of the board that we really want a high level of consensus," he said. "We don't have it here. The question is, what's going to happen over the next couple of weeks? I really hope the Members Committee vote [an advisory ballot that precedes board votes] will not be the same vote as what we just had, because that

SPP's Casey Cathey (left) and Sunny Raheem lay out the 2025 Integrated Transmission Plan to MOPC. | © *RTO Insider*

just basically punts the issue to the board and is something that clearly there's not much agreement around."

American Electric Power's Richard Ross echoed Wright in calling for a separate vote on the Seminole-Anthem portion of the 765-kV southern loop in the utility's eastern Oklahoma service territory. The project is fast becoming a reliability project, Ross said, with 2.5 GW of load added to transmission service agreements after the 2025 ITP models were locked.

"That further solidifies that this will be a reliability project in the 2026 ITP," Cathey said.

"I don't want us to get away from this meeting without addressing that issue and mitigating the risk that we delay beginning work on that project as soon as possible," Ross said, "begging" for one more vote "so that that message is clear to the board that we as a group agreed on moving forward with that particular project."

MOPC endorsed the project's approval and its projected $1.2 billion price tag, giving it 72.5% approval. Transmission owners voted 11-6 in favor, with one abstention, while transmission users approved the motion 45-11, with eight abstentions.

The committee's actions reduce the 2025 ITP's costs to $8.7 billion, SPP said. That still exceeds the record 2024 assessment, which approved permits for more than $7.6 billion in projects. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.)

SPP COO Antoine Lucas promised staff will provide more information on cost-containment measures and risk mitigation as staff takes the ITP before state commissioners and the board, saying he understood the concerns being expressed. He said staff will continue to evaluate the $7 billion in deferred projects as load forecasts continue to evolve.

"This [2025 ITP] comes in the context of increasing strain on the existing transmission network," he said. "The challenges that we've had to interconnect new generation and load without the need for tremendous new upgrade costs is a pretty good signal that the transmission system is at its limits. What we see every day in our [markets] is increasing levels of congestion, another very clear metric of very limited and — in some areas and cases — insufficient transmission."

Staff have scheduled an education session for the Regional State Committee on Oct. 24. The state commissioners do not have any say over the ITP, but Cathey said the RTO will use the session to support any regulatory concerns or necessary additional policy.

The board will take up the package during its Nov. 4 quarterly meeting in Little Rock. ■

FERC Approves SPP's New Provisional Load Process

By Tom Kleckner

FERC has approved SPP's tariff change to offer a provisional load interconnection process so the grid operator can study potential data centers and other large loads when there isn't available power for the new facilities.

In an order issued Oct. 10, the commission accepted SPP's proposal and directed the RTO to submit a compliance filing within 30 days. The order is effective retroactive to Aug. 4 (*ER25-2430*).

FERC said the new study process to evaluate requests for new loads when a transmission customer lacks sufficient existing "designated resources" to cover its 10-year load forecast (Attachment AX) will ease efforts to "appropriately and more expeditiously plan to serve their future loads."

The tariff change will also allow the RTO to identify and address the effects of load additions by finding the resulting network upgrades on its system before sufficient designated resources are available, the commission found. It said the proposed *pro forma* provisional load process agreements for customers seeking network integration and point-to-point transmission services will provide just and reasonable terms and conditions for how SPP will study new load requests under the provisional load process.

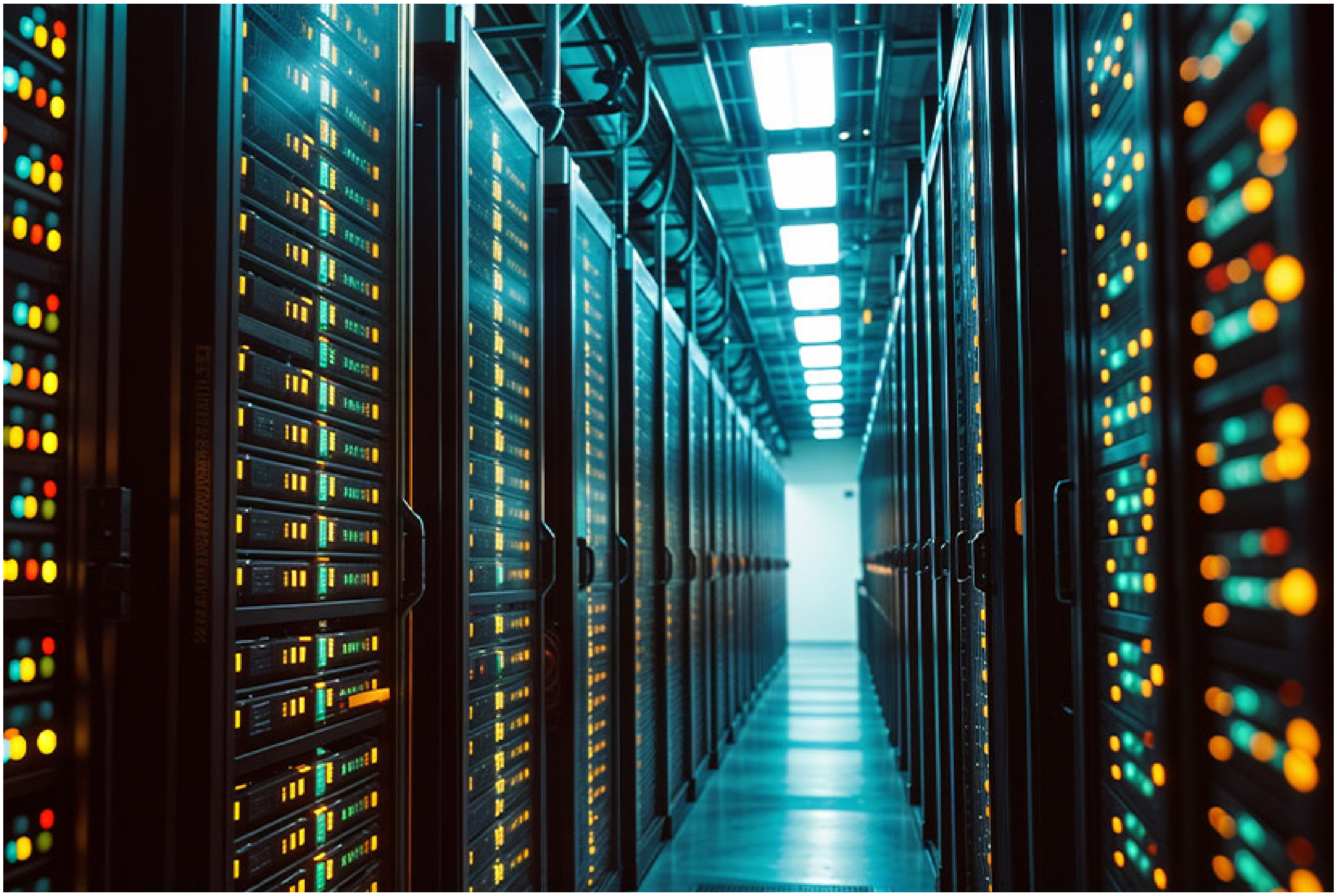
SPP filed its proposed revision in June, saying that because it was seeing increased requests for new loads from data centers and industrial facilities, many transmission customers have been "unable to demonstrate sufficient existing" resources to serve their 10-year forecasts. It said Attachment AX will mimic Attachment AQ, the grid operator's standard study process, except that it will consider a customer's planned generation and its existing designated resources.

The RTO said the provisional load process captures the expected reliability effects of planned generation on the grid and will help the transmission customer plan for serving its future load.

Upgrade costs to interconnect new load will be assigned to the customer until planned generation is included in the transmission service agreement. Remaining upgrade costs will be rolled into regional rates.

The grid operator told FERC it has received just over 26 GW of interconnection requests larger than 100 MW since 2020. Data centers account for about 9 GW of those loads, the RTO said.

SPP stakeholders approved the provisional load process in April. It was later approved by the RTO's state regulators and its board. (See "'Chicken & Egg' Issue," *New ERAS for SPP: Stakeholders Approve RA Studies*.) ■



SPP says data centers account for about 9 GW of the 26 GW in large loads that have submitted interconnection requests. | *Shutterstock*

SPP Moving Forward with JTIQ Transmission Projects

RTO in 'Wait-and-See' Mode over DOE's $464M Grant

By Tom Kleckner

LITTLE ROCK, Ark. — SPP says it plans to continue working the Joint Targeted Interconnection Queue's portfolio of five 345-kV projects on its seam with MISO, despite the U.S. Department of Energy's threat to pull $464 million in previously granted funds.

General Counsel Paul Suskie told stakeholders Oct. 14 that staff's initial internal assessment has determined "nothing stops these projects from going forward."

"They can proceed," he said during a Markets and Operations Policy Committee meeting. "We are having communications with MISO to see if they're in agreement with that. Staff's current indication is these projects will still go forward if DOE funds are pulled for the grants."

Suskie told MOPC that he called Minnesota Public Utilities Commissioner John Tuma, who confirmed that as of Oct. 13, DOE has not yet provided confirmation of the funding's termination.

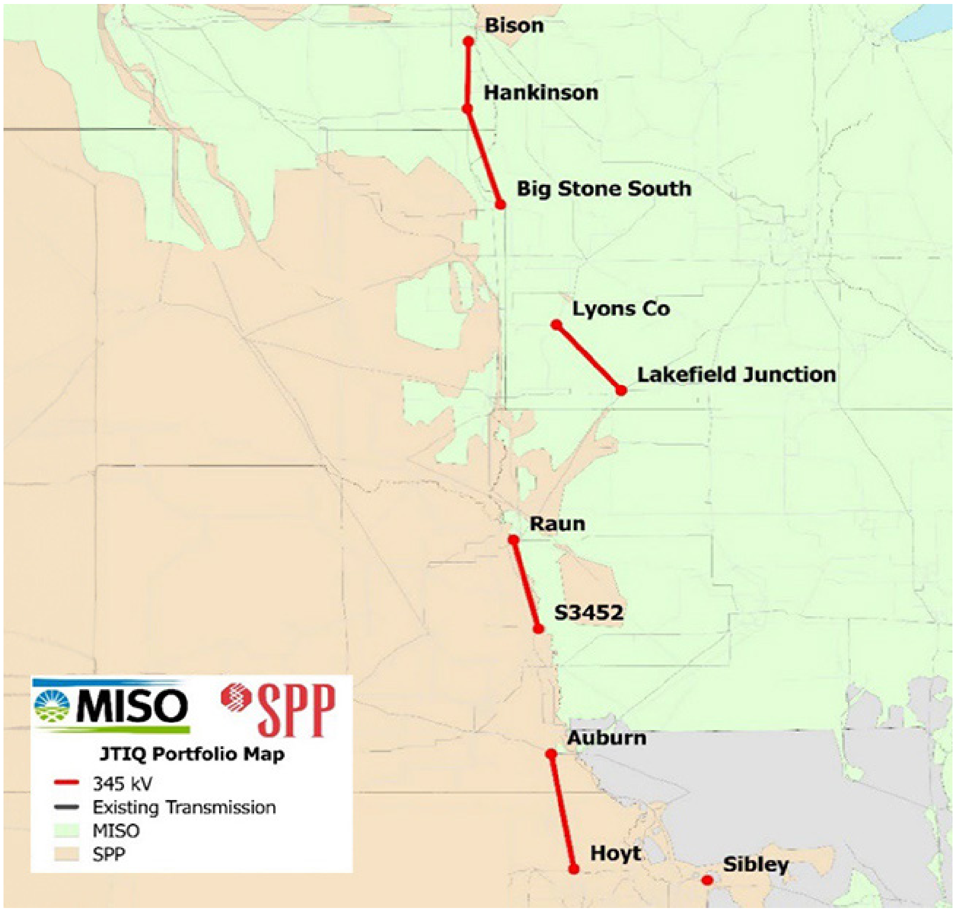
The funds were *awarded in 2023* to the Minnesota Department of Commerce, the lead applicant in the JTIQ initiative that also involves the Great Plains Institute and the two RTOs. However, the department in early October included the $464 million grant under its Grid Resilience and Innovation Partnerships (GRIP) program on a list of projects that it intended to terminate. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

POLITICO has reported that DOE has *"clashed" with the White House* over the administration's desire to spare most grants so they can be used as bargaining chips with Congress and the states, explaining the lack of confirmation from the department.

"At this point, we don't know [the grant's status]," Suskie said. "We know the rumors, the press reports. That's all we know at this point in time. Really, it's a wait-and-see game."

Why This Matters

SPP plans to continue studying the JTIQ projects in its footprint, despite the potential loss of a $464 million grant from the Department of Energy. The RTO could execute the first GI agreements in 2026.



The five 345-kV projects in the MISO-SPP JTIQ portfolio | *MISO, SPP*

MISO has said it is monitoring the situation and that like SPP and Minnesota, it has yet to receive word of the grant's termination. (See *MISO Says JTIQ Tx Portfolio Stands — for Now*.)

The GRIP funds would offset about 25% of the predicted $1.6 billion in capital costs for the JTIQ portfolio's five projects.

FERC approved the RTOs' request to allocate the portfolio's costs 100% to interconnecting generation assessed on a per-megawatt basis. In doing so, it cited the GRIP funding as one of the "unique set of facts and circumstances of the proposed JTIQ framework." (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

"This potentially has not just impacts on the practicality of these lines," the Advanced Power Alliance's Steve Gaw said during the MOPC discussion. "I'm not seeing anything that others don't see, but there are also potential legal implications from this equity impact."

The portfolio's projects are centered on the RTOs' northern seam and have been framed as enabling 28 GW of primarily renewable generation. Each grid operator would have two projects in its footprint and share the fifth.

The SPP projects will be evaluated for system impacts first through its one-time *expedited resource adequacy study* process and then through the 2024 Integrated Transmission Planning cluster. Staff have targeted March 2026 to execute ERAS generator interconnection agreements. ■

AEP Closes on $1.6B Loan Guarantee for Transmission Projects

DOE Financing Will Reduce Cost of 5,000 Miles of Line Upgrades

By John Cropley

American Electric Power has closed on a $1.6 billion U.S. Department of Energy loan guarantee to help finance 5,000 line-miles of transmission upgrades.

AEP Transmission will perform the work in Indiana, Michigan, Ohio, Oklahoma and West Virginia. It estimates the preferred interest rate deal will save ratepayers $275 million over the life of the loan while supporting economic development and technology advancements in the communities and regions served by the lines.

These benefits were emphasized by DOE officials as they *announced the loan guarantee*, which is the first closed under the Energy Dominance Financing Program created by the One Big Beautiful Bill Act in July.

"Energy is central to human lives in the United States and around the world," Energy Secretary Chris Wright said during a call with reporters Oct. 16. "It's not one sector of the economy; it's THE sector of the economy that enables all the other sectors."

DOE said electric utilities that receive loan guarantees under the DOE program must provide assurance they will pass along savings to their customers.

AEP provided *a list outlining* the 127 projects in the package. They range from a rebuild of 0.13 line-miles on the Comville-Cyril line in Oklahoma to work on 345 and 349.8 line-miles on segments of the Desoto-Sorenson line in Indiana.

In his remarks, Wright roundly criticized the energy policies of President Joe Biden and the financial support they offered for clean energy and decarbonization efforts. DOE's Loan Programs Office — which has been renamed the Energy Dominance Financing Office — was central to this, Wright said.

Why This Matters

The loan guarantee will fund needed upgrades at a lower cost.

Accordingly, DOE (like other federal agencies) has been canceling programs and funding central to Biden's green agenda since President Donald Trump began his second term. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States* and *Energy Grants Worth $24B Appear Poised for Cancellation*.)

But the review of these Biden-era awards — including AEP's $1.6 billion loan guarantee, which was *announced conditionally* Jan. 16 — is showing that "not all of them were nonsense," Wright said.

"The ones that are in the interest of the American taxpayers, in the interest of the American ratepayers, and there's a helpful role for government capital, we're happy to support those," he said.

"We don't care about authorship," he told a reporter. "You're right, this one started under the Biden administration, but it's a good project. We're happy to move forward with that. But, boy, there's a lot [of projects] that don't check those boxes."

One of those was the Grain Belt Express, an $11 billion, 800-mile HVDC project under development since 2010. (See *DOE Pulls $4.9B in Funding for Grain Belt Express*.)

A reporter asked why DOE was backing AEP but not Grain Belt.

Wright said the AEP package is "a lot of bang for the buck" that will allow for better flow of power over existing lines to support economic development and reduce costs in five states.

Grain Belt, by contrast, will be slower and far more expensive per mile because it is new construction. Beyond that, it is a fundamentally different concept.

"Ultimately, that's a commercial transaction, and it involves some market risk. Is that arbitrage big today, is that arbitrage still going to be big? Is it going to fund and pay off the construction of that transmission line? … It probably will, but it's a more commercial enterprise that's just done with private entrepreneurs and private capital."

The U.S. Department of Energy announced $1.6 billion in loan guarantees to AEP for approximately 5,000 miles of transmission upgrades in five states. | *Shutterstock*

Greg Beard, who has been running what was known as the Loan Programs Office, added: "That project had a lot of merchant risk that was yet to be solved, and a consideration was: What's appropriate for taxpayer risk and what's appropriate for private market risk?"

Wright said: "I love energy infrastructure. I have nothing against the Grain Belt Express, I suspect it will still be developed."

AEP hailed the agreement in a *news release* and said it will work with communities and landowners on siting the upgrades. CEO Bill Fehrman said earlier in 2025 that AEP will meet load growth with a capital spending plan totaling at least $54 billion. (See *AEP to Meet Load Growth with More Infrastructure*.)

He reiterated the growth in the Oct. 16 news release: "AEP is experiencing growth in energy demand that has not been seen in a generation. As the first company to close a new loan with the Trump administration under this program, we are excited to get to work on these projects to improve the service we provide to our customers." ■

NERC Requests Clarification on FERC Cold Weather Order

ERO Seeks Guidance on Biennial Filings

By Holden Mann

NERC has asked FERC to clarify the data it wants to see in biennial informational filings on the ERO's most recently approved cold weather standard, as well as whether the commission expects NERC to continue submitting the filings FERC ordered with previous versions of the standard (*RD25-7*).

FERC approved *EOP-012-3* (Extreme cold weather preparedness and operations) at its September open meeting. (See *NERC Cold Weather Standard Gains FERC Approval*.) NERC developed the standard in response to the commission's directive ordering changes to the predecessor standard EOP-012-2. That standard itself was a revision to EOP-012-1, which FERC approved in 2023 while identifying numerous needed improvements.

Commissioners did not demand further changes to EOP-012-3 but did direct the ERO to submit follow-up filings every other year, beginning no later than October 2026 and ending in October 2034. The filings stem from the standard's allowance for generator cold weather constraints — situations in which a generator owner may declare that a specific freeze-protection measure would result in a net loss of reliability on the grid — and must include:

- The number of cold weather constraint declarations submitted to each regional entity.
- The number of declarations approved, and their aggregate megavolt-amperes.
- A summary of the rationales provided for approved declarations.

What's Next

FERC ordered NERC to make its first filing regarding generator cold weather constraints on Oct. 1, 2026, and every other year thereafter. The next annual follow-up filing on EOP-012-1 is also due Oct. 1, 2026, and NERC has asked if the two filings can be combined.

Matthew T. Rader, CC BY-SA 4.0, via Wikimedia Commons

NERC also must submit a narrative analysis in the filing addressing:

- Whether reliability coordinators, transmission operators and balancing authorities are notified in a timely fashion of constraint declarations and extensions to corrective action plans (CAPs).
- The reliability impact of allowing 36 months to correct freeze-related issues, rather than a shorter time frame.
- Whether compliance enforcement authorities interpret and apply the constraint declarations approval process.
- Whether constraint declaration criteria are adequately defined and understood by registered entities.
- The reliability impact of cold weather constraint declarations and CAP extensions.

In an Oct. 17 *filing*, NERC said it shared "the commission's desire to ensure that … EOP-012-3 is advancing generator cold weather preparedness for extreme cold weather conditions," but expressed uncertainty about two elements of the order.

The first was FERC's directive that NERC report the aggregate megavolt-amperes for approved constraint declarations. NERC acknowledged that its Rules of Procedure mention megavolt-amperes in the criteria for placing entities on the ERO's Compliance Registry but observed that it analyzes generating units based only on their real power in megawatts. NERC also pointed out that EOP-012-3 does not reference megavolt-amperes.

To clear up this confusion, NERC requested that FERC clarify whether it must report by megavolt-amperes only, or if reporting the aggregate megawatts of approved constraints would suffice. If the commission insists on megavolt-amperes, NERC requested that commissioners specify why they chose this approach "so that NERC may better understand the basis for such a collection."

NERC's other request applied to the annual filings FERC directed in its approval order for EOP-012-1, which were to include a range of information on cold weather constraints and corrective action plans. Observing "significant overlap in some aspects of the information" to be collected in each order, NERC asked whether it could consolidate both reports into the biennial filing ordered for EOP-012-3, and whether this consolidated filing still would sunset in 2034. ■

NERC Preparing Workshop on FERC IBR Order

By Holden Mann

NERC is seeking comments on the agenda for a virtual workshop Nov. 5 in which the ERO will review its response to FERC Order 909, including a standards development project that aims to meet the commission's directives by 2026.

The commission issued the order in July, approving new reliability standards establishing frequency and voltage ride-through requirements for inverter-based resources. (See *FERC Approves IBR Ride-through Standards*.) One of those standards, *PRC-029-1* (Frequency and voltage ride-through requirements for IBRs), allows owners of legacy IBRs — resources already in operation when the standard goes into effect — 12 months after the effective date of the standard to request an exemption to its ride-through requirements.

Reacting to comments by industry stakeholders on its proposal to accept the standard (*RM25-3*), FERC directed NERC to clarify, within 12 months of the order's effective date, what evidence it would accept to demonstrate hardware limits throughout for legacy IBRs. Also due in 12 months was a determination of whether any additional exemptions should be made for HVDC-connected IBRs with choppers — used in offshore wind projects to protect converters during grid faults — and other IBRs with long lead times "between adopting IBR specifications and placing the IBR in service."

NERC's workshop will outline the history of the project for industry stakeholders and solicit input on the issues entailed.

One topic on the agenda for NERC's Nov. 5 workshop involves inverter-based resources equipped with choppers, which are used in offshore wind projects to protect converters during grid faults. | *Lo83, CC-BY-SA 4.0, via Wikimedia Commons*

What's Next

NERC will hold its workshop on Order 909 on Nov. 5, shortly after the beginning of a comment period on a standard authorization request aimed at satisfying the commission's directives.

Discussion panels are planned on documentation obligations for legacy IBRs and equipment limitations of IBRs with choppers that prevent them from complying with the ride-through standards of PRC-029-1.

In the final panel, participants will discuss how long-lead-time projects should be identified; whether they should be defined in the standard or left to industry to determine; potential equipment limitations from such projects; and solutions or workarounds that could address those limits. Attendees will also have the chance to provide feedback through live polling.

NERC staff have also suggested the workshop can help inform industry of relevant issues as stakeholders consider the standard authorization request (SAR) for Project 2025-05, which will handle the FERC directive. At the Oct. 15 meeting of NERC's Standards Committee, Director of Standards Development Jamie Calderon suggested extending the comment period for the SAR — which begins Oct. 29 — from 30 days to 45 days in order to give industry more time to consider the discussion at the workshop. (See related story, *NERC Standards Committee Passes Revised Proposals*.)

In its announcement of the workshop Oct. 15, NERC invited stakeholders to provide input on the agenda. Topics of interest to the ERO include factual data on the exemption process, equipment limitations of IBRs with choppers and long-lead-time projects. Comments should be submitted by email to *Alison Oswald*, manager of standards development; *Lauren Perotti*, assistant general counsel; or *Sarah Habriga*, standards development analyst. ■

State-backed Actor Breaches Enterprise Software Product Security

CISA, E-ISAC Respond to Announcement of F5 Infiltration

By Holden Mann

Networking software and hardware developer F5 has suffered a major security breach by a nation-state threat actor that gained "long-term, persistent access" to information on the widely used BIG-IP product, the company said in an Oct. 15 *statement*.

BIG-IP is a family of hardware and software products that provide a range of services to enterprise customers, including cybersecurity, network load balancing and automation. F5 claims its products are used by 85% of the Fortune 500.

In its statement, F5 said the attackers gained access to company systems including the BIG-IP development environment and engineering knowledge management platform. The company admitted in a *regulatory filing* the same day that the intruders stole files containing portions of the BIG-IP source code and information about undisclosed vulnerabilities that F5 was working to address.

Also in the stolen files was "configuration or implementation information for a small percentage of customers." F5 said it is still reviewing the files and will communicate with affected customers as needed. According to the regulatory filing, F5 learned of the unauthorized access on Aug. 9 but was allowed to delay disclosure for 30 days by the U.S. Department of Justice on Sept. 12 on the grounds that the revelation would present a national security risk.

Why This Matters

F5's BIG-IP products are used in a wide range of industries and government agencies. The intruders were able to access portions of the software's source code along with information on unpatched vulnerabilities, meaning users could be open to attacks.

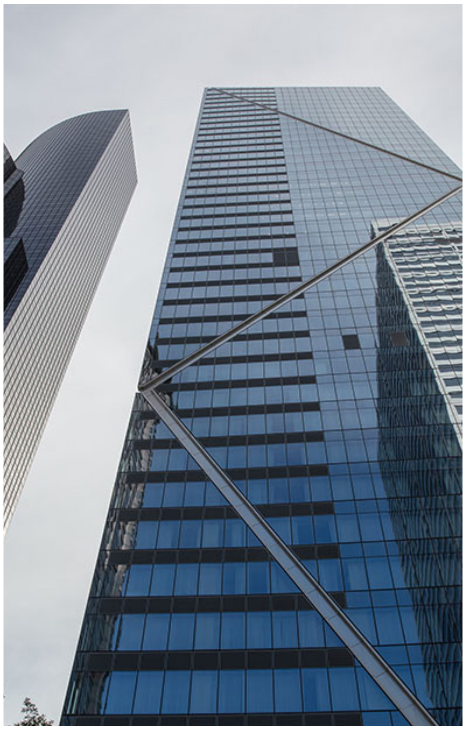
The infiltration of a product development environment by nation-state actors is reminiscent of the *SolarWinds hack* of 2020, in which attackers — now *identified* by the U.S. as belonging to Russian intelligence agencies — accessed the update channel for SolarWinds' Orion network management software and pushed code that could be used to gain access to customers' systems. After that event, FERC ordered the development of new standards requiring internal network security monitoring at electric utilities. (See *FERC Orders Internal Cyber Monitoring in Response to SolarWinds Hack*.)

That similarity might be why F5 emphasized that it had seen "no evidence of modification to our software supply chain, including our source code and out-build and release pipeline." It brought in independent cybersecurity research firms NCC Group and IOActive to validate this claim.

Those firms are also helping F5 with code review and penetration testing to identify and remediate vulnerabilities, the company wrote. Additional mitigation efforts underway include rotating credentials and strengthening access controls across all systems, hardening the development environment, and deploying improved inventory and patch management automation.

F5's recommendations for its customers include immediately updating their BIG-IP software. The company issued downloadable updates in its *quarterly security notification*, but warned that only versions of software that have not yet reached their end of technical support phase will be patched. Other resources made available by F5 are threat hunting guides, hardening guidance with a verification tool, and threat monitoring tools.

The Department of Homeland Security's Cybersecurity and Infrastructure Security Agency (CISA), responding to the disclosure of the breach, issued an *emergency directive* ordering federal agencies to inventory their F5 products and apply updates to the affected software by Oct. 22. CISA also directed agencies to harden all public-facing BIG-IP physical or virtual devices and disconnect those that are no longer supported.



F5 headquarters in Seattle | *F5*

In CISA's first *press release* since the federal government shutdown began Oct. 1, acting Director Madhu Gottumukkala said that "the alarming ease with which these vulnerabilities can be exploited … demands immediate and decisive action from all federal agencies."

NERC and the Electricity Information Sharing and Analysis Center (E-ISAC) wrote in an email to *ERO Insider* that they were "not aware of any industry impact arising from the F5 vulnerability at this time," but in the interest of caution, the E-ISAC sent an all-points bulletin to its members Oct. 15.

"The threat of cyber and physical attacks targeting critical infrastructure is not new, and ensuring a secure and reliable bulk power system is a top priority for NERC," ERO staff wrote. ■

CEC Eyes Major Cuts to Light EV Charger Funding

By David Krause

The California Energy Commission projected significant funding cuts to a key electric vehicle charging program, despite the state setting a record for the number of EVs sold in a quarter.

CEC staff on Oct. 9 published a *draft report* of the investment plan for the CEC's clean transportation program, in which forecast funding for EV charging infrastructure for light-duty vehicles dropped from $98.5 million in 2025/26 to $34.2 million in 2026/27. In 2027/28, the projected funding amount decreased slightly to $33.2 million.

But EV sales are going in the opposite direction: In Q3 of 2025, California sold about 125,000 EVs — the most recorded in a quarter in the state and about 29% of total vehicle sales in the quarter, Gov. Gavin Newsom (D) said in an Oct. 13 *news release*. The previous record occurred in Q3 2023 when about 27% of vehicles sales were EVs.

In February, California had more than 178,500 public and shared-private Level 2 and DC fast-charging ports for light-duty vehicles.

The CEC told *NetZero Insider* that the decrease in light-duty EV charging funding is due to projected increased investment from the private sector, along with reduced future state budget allocations. If either of these scenarios changes, next year's investment plan update could allocate funds differently, the CEC said.

As for medium- and heavy-duty charging infrastructure, CEC staff predicted an increase in funding from $15 million in 2025/26 to $44 million in 2026/27. About 5,800 medium- and heavy duty-vehicles were registered in the state at the end of 2024. Most of these vehicles were buses.

In total, California plans to have 1.5 million zero-emissions vehicles by 2025 and 5 million by 2030. As of June, more than 61 percent of clean transportation program and supplemental funds have gone to projects in disadvantaged or low-income communities or both, the CEC said.

EV Data Collection Approved

Separately, at an Oct. 8 business meeting, the CEC approved new EV charging data-collection regulations, which require public EV charging port owners in California to submit data about charger usage semiannually. Required data includes a charger's location, availability and pricing. The data may be shared with third parties.

Why This Matters

In the coming years, California's grid will experience large demand increases from EV growth in the state, yet the amount of CEC funding for light-duty EV charging programs is diminishing.

| Shutterstock

California will become the first state to adopt EV charging reliability and reporting regulations, CEC Commissioner Nancy Skinner said at the Oct. 8 voting meeting.

"We are laying the foundation for EV charging station reliability across the nation," Skinner said. "[EV charging] is so important for our consumers and so important to our meeting the goals of EV adoption, because if there is a sense of unreliability, then it's going to be harder for people who haven't yet gone to an EV to go there."

Publicly available Level 2 chargers have a 96% reliability of working as designed, while DC fast chargers have a 91% reliability, Skinner said.

The data collection will give the CEC, for the first time, the ability to have a comprehensive inventory of the installed chargers in this state, Skinner said. The data includes all chargers not in a residence.

"Those of us who are EV drivers, we know that we commonly use different apps or websites to find a charger," Skinner added. "Now, if the information is not widely shared, then that charger's not going to show up, and we won't know that it exists."

The regulations, Skinner said, are "going to empower us to have that inventory and to get that more publicly accessible information. So, it's just going to improve the overall EV driver experience in California." ■

Report Calls for Maryland Clean Heat Program to Target Low-income Customers

By James Downing

Maryland residents can benefit from the rollout of heat pumps the most by targeting state funds for low-income customers, according to a report released Oct. 14 by the Sierra Club's Maryland Chapter and the Center for Progressive Reform (CPR).

"Building Electrification in Maryland: Implementation of Zero-Emission Heating Equipment Standards for Low-Income Households" found that the right strategies could lead to $145 million in health benefits, $350 million in energy savings and $311 million in climate benefits.

The Climate Solutions Now Act of 2022 set up the zero-emission heating equipment standards (ZEHES) to start replacing fossil-fuel burning heating equipment at the end its life with heat pumps and heat pump water heaters starting in 2029.

The regulations implementing the ZEHES have not been written, and the report seeks to put numbers on the costs and benefits of switching to heat pumps as consumers' existing equipment needs replacement, report co-author and CPR Senior Policy Analyst Bryan Dunning said in an interview. Another factor was ensuring that low-income customers were not left behind in the transition to technology that has higher upfront costs but is cheaper over its lifetime.

"Utility bills are already high in Maryland right now, full stop," Dunning said.

The ZEHES program will require that 14,000 space heating units and up to 22,000 water heaters are replaced with heat pumps each year for low-income consumers, who will need significant help to cover those costs, according to the report. Based on the lifespan of current equipment, water heater replacements should be accomplished by 2039 and building heating equipment by 2059.

Why This Matters

The report recommends ways the state can tap existing energy funds it controls to help low-income customers install heat pumps and heat pump water heaters when a new program kicks in at the end of the decade.

"In the context of replacements for [low-income] households, modeling projects a yearly total cost of close to $300 million, with an additional cost, depending on implementation policy, of an additional $80 million for building weatherization," the report says.

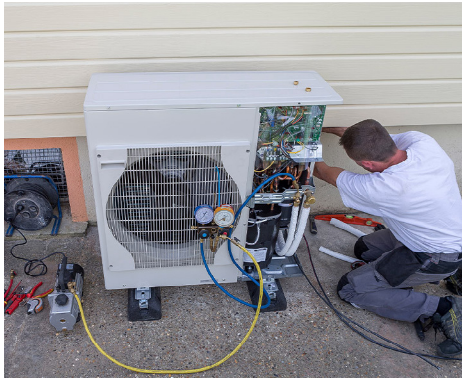
Even without the ZEHES program, the water and air heating equipment would need to be replaced at the end of its lifetime at an estimated annual cost of $185 million for low-income households.

While the benefits outweigh the costs, the state will need to help low-income customers, or their landlords, pay for the upfront costs, and recent policy changes at the federal level complicate that.

"Federal funds are not included in our pathway forward," Dunning said. "One can hope that the feds may elect to support electrification in the future again, the way they had previously done, or perhaps more so, but we did not hang our recommendations on that. So, the numbers that are in our report in terms of the costs and where cost allocation has to come from [are] totally focused on the state side of things. It's really looking at also specifically leaning on non-general fund money, so you don't need an additional allocation from the legislature."

Those funds include the Strategic Energy Investment Fund that comes from the Regional Greenhouse Gas Initiative, the EmPOWER program, the Clean Heat Standard being developed by the Maryland Department of the Environment and low- to zero-interest financing from green banks. In general, the paper recommends that bigger shares of the funding from some of those programs go to low-income consumers.

Given that the program does not start until 2029, the report suggests starting on replacing heating sources that have the biggest payback, which are oil, propane and electric resistance heating, the last of which is not part of ZEHES. But rolling out heat pumps comes with a quicker repayment period now than those that use natural gas, at just four years, while replacing electric water heaters with heat pump technology can be paid back in three years.



| Shutterstock

"Over 61% of water heaters in [low-income] Maryland homes currently employ electric resistance and would quickly benefit from replacement," the report says. "Tanked heat pump hot water heaters can heat during off-peak hours, holding the hot water until peak morning hours during the winter and peak evening hours during the summer. Because they can schedule operation, these heaters can lower peak electric demand, thus contributing to lower electric rates and reducing grid congestion."

All heat pumps have some electric resistance backups in them, which would kick in during the rare winter arctic cold snaps that impact Maryland, though generally the state's climate is well suited for the technology, Dunning said.

"Maryland exists in a bit of a Goldilocks zone climate wise," he added. "It's our position that you can do this without backups."

Backup heating sources are sometimes in states further north, but Dunning said arguments from utilities to keep natural gas heating as a backup do not make sense given the normally mild winters in Maryland. ■

Company Briefs

NARUC Welcomes 4 to Board of Directors

Four public utility commissioners last week were appointed to the NARUC Board of Directors.

Kim David (Oklahoma), Sheri Haugen-Hoffart (North Dakota), Gabriella Passidomo Smith (Florida) and Kevin Thompson (Arizona) will join the 36-member board.

More: *NARUC*

Meta to Build $1.5B Data Center in El Paso

Meta Platforms last week announced it is investing $1.5 billion to build a data center on 1,000 acres in El Paso.

El Paso Electric has developed a special electricity rate for the data center, which the utility said would require more than 100 MW and operate at 90% efficiency.

More: *El Paso Matters*

Radiant Scraps Wyoming Facility for Tennessee

Radiant Industries last week announced it has scrapped a proposal to build a nuclear microreactor manufacturing facility in Wyoming and will instead build "its first mass-produced Kaleidos microreactor" facility in Tennessee.

The R50 factory is expected to produce up to 50 emissions-free microreactors per year. Kaleidos microreactors will produce about 1 MW and can fit inside a shipping container and work independently of the grid.

The company cited Wyoming's decades-long ban on storing spent nuclear fuel waste as a reason for deciding against the state.

More: *Knoxville News Sentinel*; *WyoFile*

Federal Briefs

EEI: U.S. Utilities Planning Record Capital Expenditures

U.S. utilities are set to invest nearly as much between now and 2029 as they did in the entire previous decade, according to estimates from the Edison Electric Institute.

Utilities are on track to spend nearly $208 billion in 2025 to bolster the grid. Between 2025 and 2029, the capital expenditures are likely to hit $1.1 trillion, nearly matching the combined $1.3 trillion spent from 2015 to 2024.

The construction wave is causing some challenges, as utilities requested or secured a record $29 billion in rate increases in the first half of 2025, more than double the price of hikes this time last year.

More: *Latitude Media*

U.S. EV Sales Hit Record High in Q3

Electric vehicle sales in the U.S. hit an all-time high in the third quarter of this year with 438,487 units sold, accounting for 10.5% of total vehicle sales, according to Kelley Blue Book estimates.

The quarter volume was up 40.7% from the previous quarter and higher by 29.6% year over year.

With government-backed EV sales incentives now eliminated, making and selling EVs will become more challenging. Cox Automotive is forecasting a notable sales drop in the fourth quarter and through the early months of 2026.

More: *Cox Automotive*

Regulators Toss Climate Change Rules for Banks

A joint release from the Federal Deposit Insurance Corporation, the Office of the Comptroller of the Currency and the Federal Reserve said they are doing away with rules that required banks to plan for losses in the event of climate-related events.

The regulators said they no longer believe the requirements are necessary as they are redundant with other provisions banks make to plan for emergencies and unusual events.

The climate change provisions were established in October 2023.

More: *CNBC*

State Briefs

COLORADO

United Power Signs on for Solar-plus-storage Output

United Power last week announced an agreement to receive power from a 200-MW solar facility combined with 150 MW of battery storage.

The Fortress, developed and owned by Aypa Power, is scheduled to be operational in 2027 under a long-term power purchase agreement.

More: *Big Pivots*

CONNECTICUT

Siting Council Rejects United Illuminating Tx Line

The Siting Council last week voted 5-3 to reject United Illuminating's application to build its proposed Fairfield to Congress Railroad Transmission Line.

The decision marked the latest twist in the yearslong saga over the project. In September, the council held a non-binding straw poll in which a majority of members signaled their intent to support UI's application. That was a reversal of the council's previous stance in June, when a majority of members voted to oppose the project. There was little public discussion among members last week as to why they changed their minds again.

UI did not immediately say whether it would appeal the decision.

More: *Hartford Courant*

INDIANA

AES Slashes Rate Increase Request

AES Indiana slashed its $193 million base rate increase request by more than half — to $91 million — in a settlement agreement filed with the Utility Regulatory Commission.

The agreement would lower the revenue requirement AES Indiana seeks from $2.1 billion to $2 billion. The utility would also agree to not implement new base rates arising out of its next case until 2030 and delay the start of its next proposed transmission, distribution and storage improvement charge plan until 2028. The current plan enters its final year in 2026.

The URC will not decide on the matter until next year.

More: *Indiana Capital Chronicle*

Report: BlackRock Nearing Deal for AES

Several publications have linked BlackRock-owned Global Infrastructure Partners to a $38 billion deal to acquire AES. The *Financial Times* first reported in early October that BlackRock was nearing a deal.

BlackRock is one of the largest asset managers in the world, with more than $11 billion in assets. It acquired Global Infrastructure Partners for $12.5 billion last year.

Both BlackRock and AES declined comment.

More: *Indianapolis Star*

LOUISIANA

Judge: Cameron Parish LNG Permit Ignored Potential Climate Impacts

Judge Penelope Richard last week ruled that state officials violated the state constitution when they issued a permit for the Commonwealth LNG export facility, which has halted construction.

The decision found that the Department of Conservation and Energy failed to consider the environmental impacts on surrounding communities when it approved the permit for the facility. The permit will be suspended until the Office of Coastal Management considers climate change and environmental justice concerns in its evaluation, according to the ruling.

The facility is one of six LNG export projects proposed, approved or operating along the Cameron Parish coast.

More: *Louisiana Illuminator*

MICHIGAN

State Raises Annual EV Registration Fees

The state last week announced it has raised its annual EV registration cost to $260 – up 63% from the previous year.

The change moves Michigan from the middle of the pack up to a two-way tie for the nation's highest EV taxes, according to the Energy Innovation Business Council.

More: *MLive*

NEBRASKA

OPPD Delays Coal Plant Transition Vote

The Omaha Public Power District Board of Directors last week delayed a vote on whether to move forward with converting North Omaha Station Units 4 and 5 from coal to natural gas.

The utility says it's taking additional time to review recent developments and ensure its plans align with long-term energy goals.

The plant is slated to end coal operations in 2026.

More: *KMTV*

VIRGINIA

Mecklenburg County Rejects Solar Farm

The Mecklenburg County Board of Supervisors last week voted 6-2 to reject the proposed Finneywood Solar Project.

The board voted down a proposed siting agreement and special exception permit application by Dominion Energy, which sought to build and operate the 98-MW facility on 997 acres.

Coupled with an April decision to remove utility-scale solar as an allowed land use under the county zoning ordinance, the door appears shut for future utility-scale solar projects in the county.

More: *Mecklenburg Sun*

WYOMING

PSC Appeals Judge's Ruling in PacifiCorp Rate Case

The Public Service Commission filed notice earlier this month that it will appeal a federal judge's ruling that sided with PacifiCorp in its rate case.

Lawyers representing the PSC gave notice they would ask the 10th U.S. Circuit Court of Appeals to weigh in on the matter of District Judge Kelly H. Rankin's approval of the utility's rate increase request. PacifiCorp filed a lawsuit last year after the PSC reduced what had initially been a 29.2% rate hike to 5.5%. The lawsuit alleged the commission wrongly reduced the rate hike by ignoring federal requirements, costing the utility $23 million.

More: *WyoFile*