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YES ENERGY

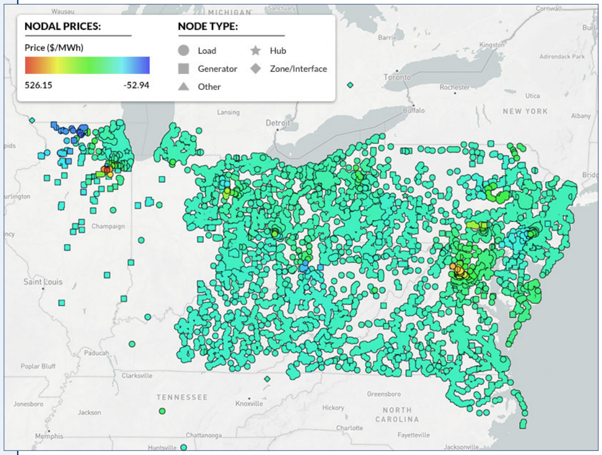
RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ IESO ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

PJM

N.J. Mulls PJM Withdrawal amid Energy Shortfall Predictions



Yes Energy

One difficulty with New Jersey departing PJM would be the sheer logistics of setting up a new system, coupled with coordination issues associated with adding other states to the mix that would be needed to make the venture viable.

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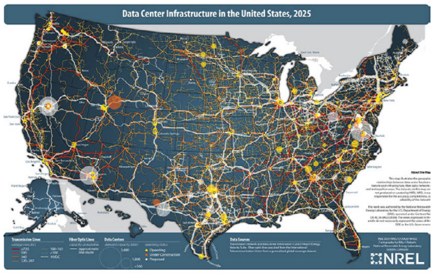

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In this week's issue

Texas' Renewable Energy Bubble

By Doug Sheridan

While pundits wrangle over the implications of the One Big Beautiful Bill Act for America's power sector, Texas has managed to blow itself a renewable-energy bubble — one spawning so much *solar and wind energy* that the kind of generation it actually needs sits on the drawing board.

The culprit? A mix of federal incentives and state policies that turned the state's grid into a speculative sandbox for developers chasing subsidies rather than serving actual energy demand.

In recent years, ERCOT has enjoyed a reputation for fast interconnections and friendly regulatory treatments for new generation. This has spurred the rush by renewables developers to use the system to monetize federal investment tax credits (ITCs) for their projects before tax codes change.

Current law affords investors in qualifying projects a tax credit equal to 30% of the original cost of the project. In reality, the tax breaks are even larger. According to Neil Booth of Orbis Consulting, under *current IRS guidance*, project developers may immediately "step up" the value of a project's equipment to a higher value on the basis that the economic value of the equipment is higher once connected to the grid.

This accounting maneuver and other add-ons mean tax-equity investors can recoup 100% of their investment as soon as 90 days after a project goes live. It doesn't take a genius to understand how such a siren call of quick returns can incentivize investors to target the one grid on which they can get their projects online as fast as possible — irrespective of whether that grid needs the incremental intermittent power.

Companies like Meta, Microsoft, Amazon and Google add their own distortions. These *hyperscalers* sign long-term power-purchase agreements (PPAs) with renewables developers to help brand themselves as "green" operators. On its face, this makes it seem like corporate America is doing its part to decarbonize. In practice, it's not clear how many hyperscalers are in fact consuming the electrons for which they have contracted.

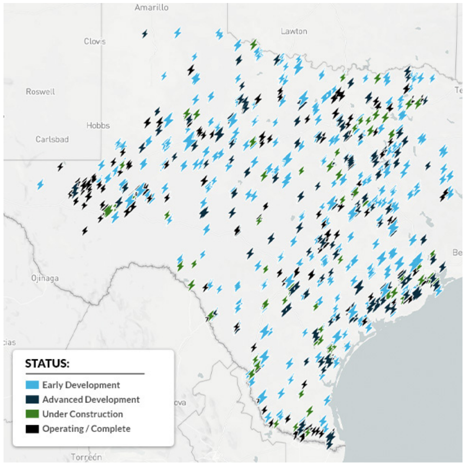
Instead, hyperscalers may simply pay for the renewable power per the PPA, then sell it back into ERCOT's wholesale market. This affords their operations the environmental seal of approval they seek, even though their facilities might be running on gas-fired generation in other states. Meanwhile, the intermittent power from the renewables is being dumped onto the Texas grid without a stable, long-term customer — undermining both supply and demand fundamentals, as well as prices for the dispatchable power needed to balance the system.

The EIA reports that Texas added a net 29.2 GW of supply from 2022 to 2024. Subsidized solar, wind and battery capacity represented 97.9% of this. More capacity has since been added, and ERCOT now reports 86.8 GW of renewables on its system — for a grid with an all-time demand peak of less than 90 GW.

NERC has taken note, pegging ERCOT's on-peak *reserve margin* at more than 40%. In a rational market, this would slam the brakes on further buildout of renewables. Instead, ERCOT's interconnection queue shows 374 GW of new renewable and battery projects interested in connecting to the system—more than 10 times all other resource types combined.

Meanwhile, despite leading the nation in natural gas production, Texas has seen developer interest in newbuild gas-fired generation nearly vanish. The problem is developers can't pencil out viable projects when first-in-line solar, wind and batteries crush revenue expectations.

As a result, the new combined-cycle and peaking plants needed to keep the grid stable during peak hours and weather lulls and to back up renewables are effectively locked out of the Texas market. This has left ERCOT's administrators with little choice but to continue connecting more part-time renewables.



Over 1,100 battery energy storage projects under construction or in development across the ERCOT region, totaling 180.5 GW of planned capacity. | *Yes Energy*

Texas' booming population, rising EV adoption and prospective surge in on-grid data center demand all point to the need for more dependable, around-the clock generation. Instead, the state is hardwiring increasing amounts of intermittent energy — and the operational costs and complexities that come with it — into its grid. *What's more*, over 40% of its nuclear, coal and gas-fired capacity is 30 years old or older. Aging infrastructure and falling revenues can lead to delayed maintenance and lower investment, putting reliability at risk.

Unless Texas policymakers change course, the consequences of swelling market distortions will become harder to manage. A grid saturated with financially engineered, subsidy-seeking projects won't in the long run deliver stable prices or dependable service. Without serious reform, Texas faces a future of inflated rates, reliability challenges and growing dependence on taxpayer-funded interventions.

It's time to restore the integrity of ERCOT's wholesale power market and re-center its grid planning around the kind of dispatchable power that can deliver when Texans need it. Otherwise, this renewables bubble won't just pop. It will burst — with the state's energy security caught in the fallout. ■

Doug Sheridan is President of EnergyPoint Research in Houston, Texas.

Your Opinion Matters

The regulatory environment for electricity is in constant motion. *Submit your insights* to our Stakeholder Soapbox.

Doubt Cast from Different Angle on Data Center Load Demand

Report Concludes There Won't be Enough Semiconductors for Projected Buildout

By John Cropley

A new analysis concludes there will not be enough computer chips produced in the entire world to supply the data centers some sources predict will be built just in the United States.

The report is the latest of many doubts raised about sky-high expectations for data center load growth, and it warns about the huge cost of overbuilding the grid to meet the highest 2030 projections.

The projections are varied, but most are large, and they are driving policy-making discussions.

On July 7, the *U.S. Department of Energy released* a *resource adequacy report* noting that various organizations' estimates of U.S. data center load growth by 2030 range from 35 to 108 GW.

DOE adopted a midpoint assumption of 50 GW — plus 51 GW of non-data center load growth — to conclude the nation will be unable to meet projected demand "absent decisive intervention" because 104 GW of baseload retirement and only 22 GW of new baseload generation is planned by 2030. (See *DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030*.)

The DOE report called for rapid and robust reforms, lest adversary nations shape the digital norms and control digital infrastructure.

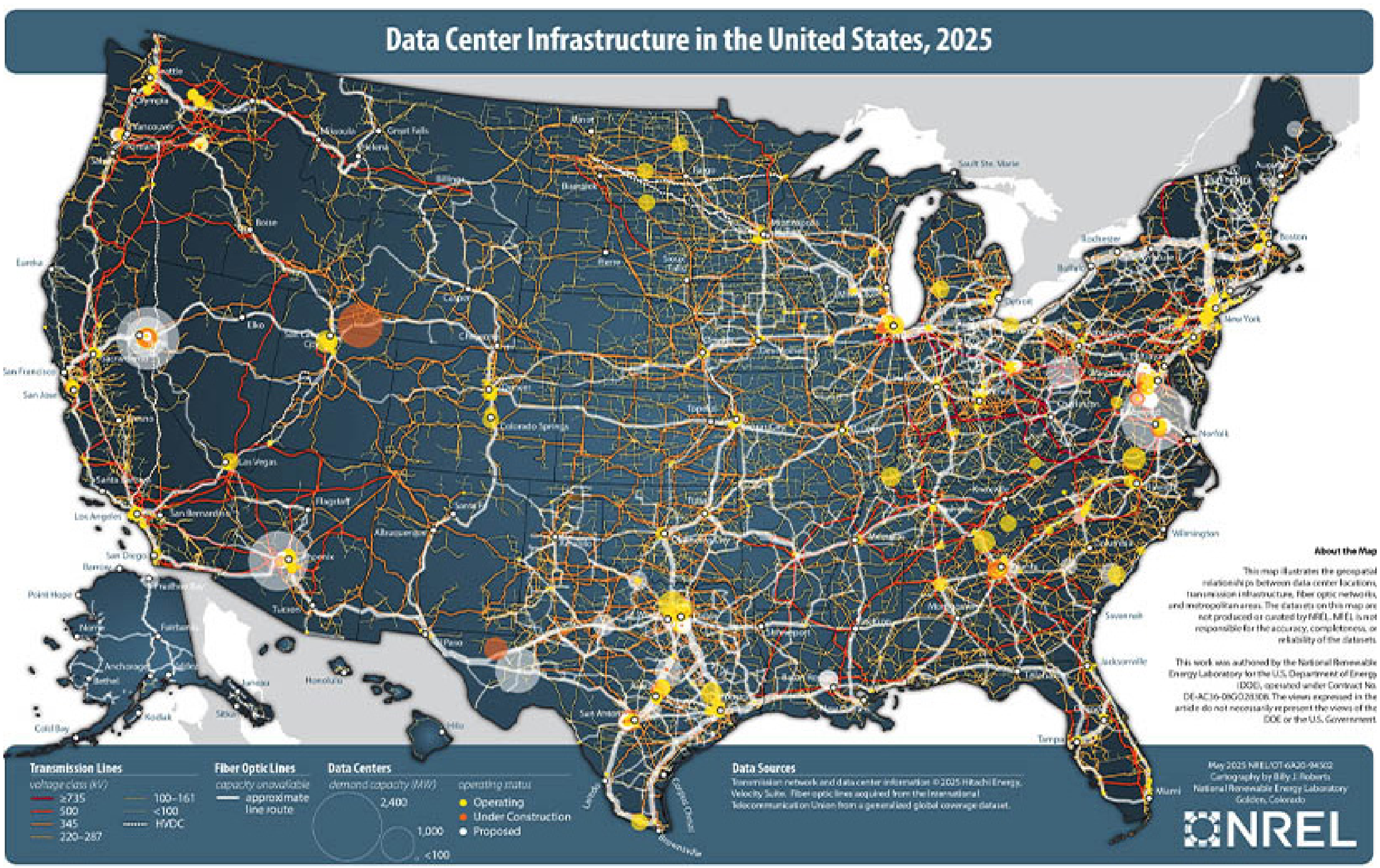
But others say these are the latest overestimations of a trend and that Big Tech will not need all this electricity.

Why This Matters

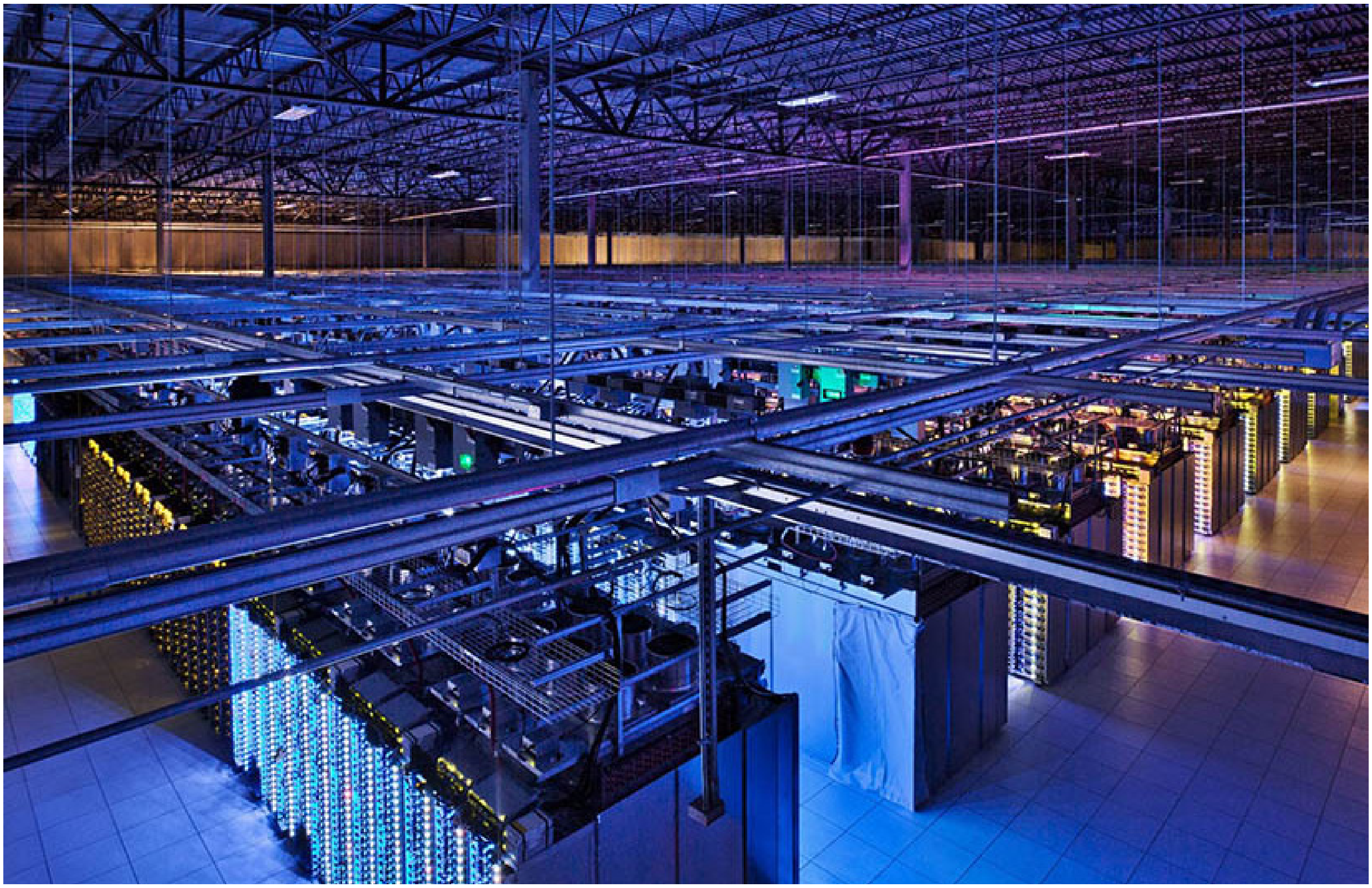
The report attempts to show that some estimates of data center load growth are too large because it is impossible to secure the equipment for them.

"Uncertainty and Upward Bias are Inherent in Data Center Electricity Demand Projections" was written by *London Economics International* (LEI) and commissioned by the *Southern Environmental Law Center* (SELC). It also was released July 7.

LEI totaled the projections of data center load growth from RTOs, ISOs and balancing areas covering 77% of U.S. electric load; surveyed global projections for



A National Renewable Energy Laboratory map shows data centers and supporting infrastructure circa 2025. | *NREL*



The interior of Google's data center in Council Bluffs, Iowa | *Google*

semiconductor chip production and supply; and factored in potential increases in chip energy efficiency and computing capacity.

They concluded that under the implied projection of 57 GW of data center load growth, the U.S. would need to buy 90% of all chips produced worldwide from 2025 through 2030, and said that scenario is unlikely — the U.S. now buys less than 50% of the global chip supply, and other nations are ratcheting up their own data center development.

LEI said these calculations support the anecdotal evidence that data center developers are submitting duplicate requests for grid interconnection in multiple jurisdictions that are being misinterpreted as unique requests.

However, the totals are being treated as real by some policymakers.

President Donald Trump is easing and speeding the regulatory process in response to the *national energy emergency* he declared on the first day of his second term, in part to "power the next generation of technology" and "remain at the forefront technological innovation."

This speedup raises environmental and safety questions for some observers, as well as financial worries: If more pipelines, wires and generators are built than data centers need, someone else will have to pay for the resulting overcapacity.

This is a central concern cited by SELC, which is headquartered in Virginia, home to the world's *largest concentration of data centers*.

"This report underscores a critical and ongoing concern: Inflated and speculative data center electricity demand forecasts in the Southeast are driving a dramatic and unnecessary overbuild of infrastructure that threatens to lock in fossil fuels, hike energy bills and crowd out more reliable, cost-effective clean energy," said Megan Gibson, senior attorney at SELC. "Such speculative infrastructure investment creates significant economic risks for ratepayers, who ultimately bear the financial burdens."

Beyond the fundamental constraint of there not being enough semiconductor chips to supply the highest projections of data center growth, SELC noted, there are limits to powering a fleet of new data centers: There are equipment shortages for new large-scale natural gas-fired plants, nuclear reactors are expensive and slow to build, new-build coal appears unlikely, and wind and solar generation suffered major setbacks in the reconciliation bill Trump signed July 4. (See related story *U.S. Clean Energy Sector Faces Cuts and Limitations*.)

Shelley Robbins, the Southern Alliance for Clean Energy's senior decarbonization manager, said there is immense financial incentive for suppliers and developers to game the system and overestimate demand.

"Data center growth has become a suspiciously convenient justification for pipeline and gas plant projects in the Southeast. Pipeline and utility companies make most of their money by building big things and then charging ratepayers for them," Robbins said. "The result will be an expensive overbuild if we do not carefully scrutinize the genuine likelihood that data center loads will actually materialize." ■

Chang Highlights Interrelated Challenges Facing Industry at WIRES

By James Downing

FERC Commissioner Judy Chang said at the WIRES Group Summer Meeting that it's vital the power industry expand infrastructure to reliably and affordably meet rising demand.

"There is some misalignment in the interconnection process and the transmission planning process and the competitive market," Chang said July 10 in Woodstock, Vt. "So, without getting into the details of dockets that I cannot discuss here, I do see this moment where there are challenges to the way we traditionally think about open access and competitive access to transmission, and that has created some logjams at the interconnection level."

Chang said she's not a big fan of temporary fixes and would rather have the overall process improved, maintaining open access and competition so generators interconnecting the grid know the rules of the game.

"All of you in this room are at the front end of that issue, which is, how do we allocate the cost of interconnection-related upgrades?" Chang said. "How do you build them? How do you build them fast enough? How do you interconnect generators fast enough? And of course, the generators have their jobs to do as well."

Industry and regulators need to come up with enduring solutions before it leads to a backlash, she said, with rising prices leading to a new wave of skepticism of markets and some states considering changing their longstanding market policies.

Why This Matters

Commissioner Chang diagnosed the challenges facing the industry, which have led to a new wave of skepticism of markets in some of the earliest states to embrace the concept.

"I worry about how much states might be willing to compromise the open access and competitive access to transmission and competitive markets by pulling back and finding interim solutions, or by complaining about competitive markets not meeting the challenge of the day," Chang said.

FERC looks at transmission planning, interconnection and wholesale market issues separately, but they all are related and, taken together, represent a comprehensive way of thinking about the power system, she continued.

"I think we still have a lot of work to do to make sure that we uphold competitive markets, open access to transmission, and make sure that we plan and implement and invest in transmission in an adequate way for the future," Chang said. "These are the major challenges in front of us. Ultimately, we need to ensure reliable service to all customers while keeping the cost down."

Transmission planning is key to addressing those challenges, and it comes with its own tensions of ensuring developers have the right access to capital without overburdening consumers' wallets, she said.

"I've worked enough in the transmission sphere of the business to know that while we want to build infrastructure and beneficial infrastructure, if we go overboard, consumers will complain and this whole thing is going to backfire," Chang said. "So, I'm concerned about that, and I hope you are keeping that in your line of sight as well. We have to be responsible in making sure that we're building the most beneficial projects."

Order 1920 provides a good basis for the industry to work through that balancing of interests, ensuring the right mix of transmission is available to meet rising demand at a reasonable cost, she added.

Consumer groups need to understand why the transmission projects in long-term plans are picked, she argued, and the industry can help accomplish that by being transparent about why the plans were developed and what issues the projects are addressing.

FERC Commissioner Judy Chang | © *RTO Insider*

Chang encouraged the transmission side of the industry to be creative and embrace new technologies, which fall under the umbrella of grid-enhancing technologies, and to explain to FERC what they want if they need help with implementation.

"Whatever it is that you need, come and talk to us," Chang said. "But I really see this as not only the future, but the present, right? I think the U.S. needs to lead in technological innovation, and you're part of that equation. All the transmission companies are part of that equation."

Chang has been at FERC for slightly more than a year, and she said the commission is busy with pending issues. Its staff members are stretched thin, as some took buyouts from the Trump administration to retire early, and they have not been replaced due to the commission abiding by a federal hiring freeze.

"Under Chair [Mark] Christie's leadership, we've been able to keep working hard," she said. "And I would say that it seems like that's actually working out."

Chang was one of three commissioners to join FERC about a year ago, and she said the group works well together with Christie. They all have different backgrounds and different areas of focus in FERC's jurisdiction.

"We've been able to talk through all of those things," she added. "When dockets before us are contentious, we take the time to listen to each other. And it's been really just a great experience working with them." ■

U.S. Clean Energy Sector Faces Cuts and Limits

Just How Ugly the Big Beautiful Bill Will be for Wind and Solar has Yet to be Determined

By John Cropley

Why This Matters

Extensive impacts are expected on energy generation, the environment and the economy.

The winners and losers in the energy sector are delineated clearly by the *One Big Beautiful Bill Act* engineered by President Donald Trump.

But it remains to be seen how big the losses will be for wind and solar power, and how many caveats accompany the wins scored by fossil fuels.

On July 7, three days after he signed OBBBA into law, Trump *issued an executive order* with strict-sounding directions for carrying out the bill's provisions targeting wind and solar energy, with critical details to be determined in weeks and months to come.

His on-again-off-again tariff threats — not least the 50% levy on *copper imports* he announced July 8 — could impose significant costs on the fossil fuel industry, which OBBBA clearly was intended to benefit.

What is clear now is that development of wind and solar power — which provided *14% of utility-scale generation* in the United States in 2023 and accounted for *78% of capacity additions* in 2024 — will become significantly more expensive.

New projects will need to begin construction by July 5, 2026, or be placed in service by Dec. 31, 2027, to qualify for the generous investment and production tax credits of the 2022 Inflation Reduction Act — a much earlier sunset than specified by the IRA but not as fast a termination as was sought by the strongest critics.

Wind and solar developers also will need to follow complex rules pertaining to fire-walling their projects' finances from FEOCs — foreign entities of concern, particularly in China. (Norton Rose Fulbright needed *more than 3,200 words* for a FEOC explainer it published July 8. The Bipartisan Policy Center *needed nearly 3,000*.)

Peter Fox-Penner, an energy policy and strategy expert and a principal at The Brattle Group, told *RTO Insider* that the energy provisions of the 800-page OBBBA are a clear and significant threat to wind and solar power development, both of which are frequent verbal targets for Trump.

"I'm struck by what a direct assault this is, in particular on wind and solar, talking about the supply side of electricity," Fox-Penner said. Combined with measures targeting residential energy efficiency and electric vehicles, OBBBA is a major change for many aspects of the energy sector, he added, as well as for the economy, domestic manufacturing, electricity ratepayers and the environment.

Not everyone is unhappy with OBBA.

Some other emissions-free technologies — geothermal, hydropower, storage — do not face the same rapid and drastic tax credit cutbacks as wind and solar.

And the fossil fuel sector — oil, natural gas, coal — has much to smile about.

"This is the most important energy bill in a generation," *American Petroleum Institute* CEO Mike Sommers said in a news release. "President Trump has delivered on his promise to unleash American energy by unlocking opportunities for investment, supporting global competitiveness and opening lease sales onshore and offshore from the Gulf of America to Alaska."

But many entities in the renewable energy and environmental advocacy sectors are not smiling at all:

- "A vote that will live in infamy." — *Greenpeace*
- "This stands to be the biggest job-killing bill in the history of this country." — *North America's Building Trades Unions*
- "This bill will be a major step backwards on energy security, prices and jobs in communities across the country." — *Clean Energy Business Network*
- "Ceding the race to build the clean energy economy of tomorrow to China." — *Sierra Club*
- "The clean energy provisions in the legislation President Trump championed will prove devastating." — *Environmental Defense Fund*
- "Congress has turned its back on the very industries that are adding the majority of the new electricity generating capacity to the grid." — *Solar Energy Industries Association*
- "Whatever promises the White House may have made when twisting the arms of some House Republicans, the Treasury Department has a duty to administer the law fairly, in a way that provides certainty to the businesses relying on these tax credits." — *National Resources Defense Council*

The NRDC comment pertains to Trump's July 7 executive order, in which he orders the strictest possible enforcement of OBBBA's provisions on construction start dates, safe harboring and FEOCs.

And it alludes to Trump's reported promise to the House Freedom Caucus — which was unhappy with even the limited leeway being given to wind and solar — that his administration would use its executive powers to the maximum extent in limiting wind and solar subsidies.

On July 3, U.S. Rep. Ralph Norman (R-S.C.), a founding member of the caucus, *explained this in a CNBC interview*.

A day after Trump's executive order, Norman *posted on Facebook*: "This order dismantles the green energy giveaways pushed under the Biden administration — programs that propped up costly, inconsistent sources like wind and solar while leaving taxpayers on the hook and our grid exposed to instability."

So what will Trump do now?

His executive order was strongly worded. But he often speaks in strong terms, and he changes his stance often.

Trump has long followed what is *sometimes called* the *Trump Uncertainty Principle*, keeping *everyone guessing* about his strategy so they cannot counter it.

He is hardly the first president with such an approach — President Richard Nixon had the *Madman Theory* — but Trump has embraced it more openly than most.

For the offshore wind industry, struggling to build momentum in the United States, the uncertainty presented merely by Trump's re-election was enough that multiple developers paused their U.S. projects.

For the established solar and onshore wind industries, OBBBA presents a more nuanced challenge, particularly with projects that are not ready to break ground and might not qualify for subsidies under terms that may be revised or re-interpreted.

Some projects will be delayed or canceled because the financial calculations on which they are based will change for the worse.

Some of the domestic manufacturing facilities that were to be a legacy of the IRA will not be built. E2 counts *$15.5 billion worth of cancellations* from January through May, and that is just the publicly announced cancellations.

This in turn means continued reliance on foreign manufacturing that is potentially subject to Trump's tariffs and OBBBA's FEOC rules.

And there's that word again — "potentially." The beauty of creating uncertainty through vague wording and implied threat is that general trepidation cannot be challenged in court the way a stop-work order or funding clawback could be. The profit-driven private sector is left to ponder the odds as it weighs investment decisions.

"I do think we see some of that, in the sense that the developers and the financial community that finances the developers [are] aware of the uncertainties and the unpredictability of the federal policies now," Fox-Penner said. "And I do think that has an incremental effect on them. I can't quantify it, but I think it is there."

He added: "It is, I think, part of a conscious policy to try and slow [wind, solar and EV adoption] down."

Princeton University's ZERO Lab *projects $500 billion* in lost capital investments through 2035 because of OBBBA and calculates Americans' annual energy expenditures will be $52 billion higher in 2035. It projects that clean energy production will continue to increase but will be 820 TWh lower in 2035 because of OBBBA than it would have been in mid-range projections under Biden-era policies.

Fox-Penner agrees: Solar and wind generation will continue to be built. Not as much as there would have been, he said, and not enough to meet the growing U.S. demand for power, but dozens of new gigawatts still will come online, despite OBBBA.

Wind and solar are so much faster and cheaper to build than other types of generation that they will carry on, albeit at a slower pace, he explained.

President Trump signs the One Big Beautiful Bill Act into law in a July 4 ceremony at the White House. | *The White House*

"We have done some analysis at Brattle Group and others have done some analysis that shows that wind and solar construction will be adversely affected substantially by this bill. But at the same time, it will continue at a significant pace in parts of the country even without these subsidies, because it remains the cheapest form of raw kilowatt hours," Fox-Penner said.

In regions where electricity is expensive, wind and solar still could be economical without federal subsidies, he added.

The problem in some of those expensive electricity markets is that the cost of energy development also is expensive, and there is no quick replacement at the state or regional level for the disappearing federal tax credits.

New York is such a place — it has grand ambitions for renewable energy and is placing much of the cost of decarbonizing the grid on ratepayers who already have some of the most expensive electricity in the nation. Further subsidies would be a hard decision to make.

The New York State Energy Research and Development Authority, which helps manage the state's clean energy transition, told *RTO Insider* it has not fully analyzed the impacts of OBBBA but implied that they would be considerable.

A spokesperson said: "The new law puts thousands of jobs at risk and could cut billions in funding and impact overall market momentum. This bill undermines New York state's demonstrated leadership in advancing clean energy technologies as a part of an all-of-the-above energy strategy including investments in wind, solar, hydroelectric and nuclear power to create a clean, affordable and reliable energy grid."

Fox-Penner said there is no quick way to refill the pipeline and meet rising demand with other technologies if solar and wind projects are cancelled.

The backlog on large gas turbine orders is several years long, and construction of new nuclear generation may not scale up before the mid-2030s. Few observers expect anything beyond delayed retirements for coal, either.

"We do not see evidence of any significant expansion in coal to date, nor do we think it makes economic or environmental sense," Fox-Penner said. ■

Federalist Society, Peskoe Debate Competition in the Power Industry

By James Downing

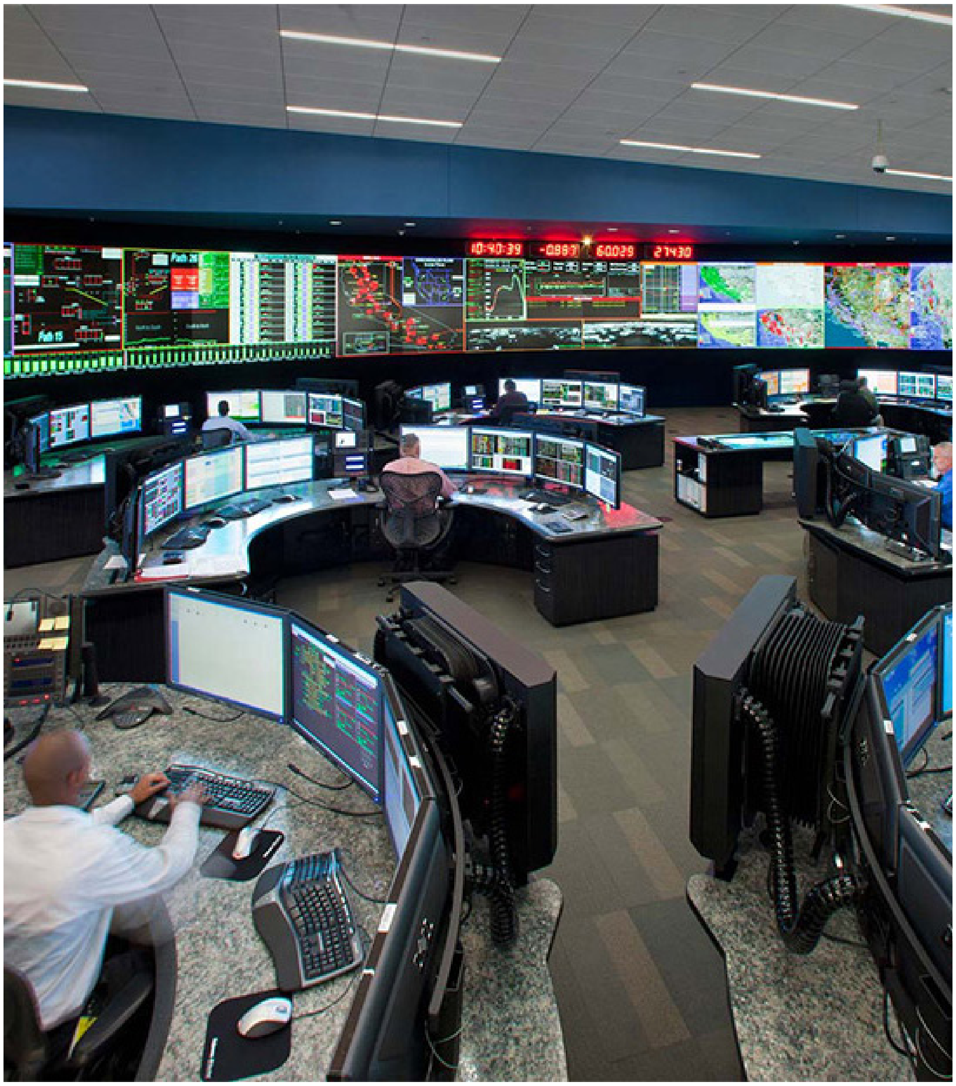
The Federalist Society held a webinar July 9 looking into whether the federal government should continue to rely on wholesale electricity markets in the face of rising prices and narrowing reserve margins.

The development of markets came from the states, many of which — enabled by FERC guaranteeing open access to transmission in Order 888 after some prompting from Congress — restructured their utility industries beginning in the 1990s, recalled Harvard Law School Electricity Law Initiative Director Ari Peskoe.

States started to restructure after several bad bets by utilities, largely on nuclear power, with Peskoe highlighting a project Boston Edison invested in that never got built and led to losses that equaled the firm's profits in its entire history.

"This would have bankrupted the utility if they had to absorb all the losses," Peskoe said. "What often happened in these cases was that utility shareholders paid some and ratepayers paid a lot as well. … The one here in Boston was never even finished, so they got paid money for nothing. So, this is a risk allocation problem."

Restructuring the utility removed the regulated wires firm from the generation function, though often those firms kept



CAISO control room | *CAISO*

Why This Matters

The debate over whether or not to rely on wholesale electricity markets comes amid challenges such as rising prices and narrowing reserve margins.

subsidiaries that were involved in new markets for generation.

"Now there's a problem, though, with the development of these markets, which is that utilities controlled market access that would give them an unfair advantage in these new markets. No one's going to invest in the market if it's controlled by the utilities," Peskoe said.

That brings up the issue of market power, which can be dealt with via transmission that investor-owned utilities had always used to improve their own systems' reliability and enhance trading opportunities with their neighbors.

"Transmission is the industry's medium of coordination that enables the industry to unlock for short-run and long-run efficiencies through trading real-time operations and joint planning," Peskoe said. "But to be more straightforward about it, if you control transmission, you can decide who generates power, where it's generated, the types of fuels used and where it's delivered to."

FERC had the authority to prevent "unduly discriminatory" transmission practices for decades, but it was not until the 1990s that it imposed open access on the industry to ensure the new competitors in the generation space, and smaller cooperatives and municipal-owned utilities that had complaints about the old system, could access the grid.

"FERC's goal was to harness markets to generate power, and it had the idea that really to do that effectively, what you have to do is separate transmission ownership from its control," Peskoe said. "FERC encouraged utilities to create new entities that it called independent system operators. These would be entities that would oversee and implement FERC open-access transmission rules."

The ISOs and RTOs developed markets that the competitive suppliers could bid into and planned the transmission grid that enabled that to happen.

But markets have always had their detractors, and the Federalist Society's John Kennerly Davis Jr., who is a former assistant attorney general in Virginia and worked for Dominion Energy, said one issue is that restructuring has just made things more complicated.

"One thing about the state-centered model was that it was a regulatory system that oversaw and held accountable a single corporation, for the provision of cost-effective, reliable electric service in the franchise service territory," Davis said. "Now the corporate form emerged a long time ago, I think sometime in the early 1600s, and it has endured over the centuries because it's a very powerful legal mechanism that combines efficiency with accountability."

Accountability is a powerful concept and one that can be tricky in the restructured markets, he continued. NYISO might have knitted together seven utility systems into one grid, but its management process involves hundreds of stakeholders, and that model has been repeated around the country.

"No one entity — not a transmission utility, not a power generator, not an ancillary service provider — no single entity in this disaggregated model is responsible to provide electric service like the traditional integrated corporate utility was under the traditional model," Davis said.

The utilities are still in charge of the distribution system, which is where most outages occur, Peskoe noted. On that level, states' ability to hold them accountable has been untouched, he said.

"I would argue that some of the best examples of regulators actually holding utilities accountable are in the restructured states where you've had winter storms; for example, in my part of the country here, where there have been pretty significant punishments laid down by regulators," Peskoe said. "So, accountability is only as good as the regulators are willing to sort of punish the utilities for poor performance."

Davis also argued that subsidized renewables are driving down the prices for other technologies and making the grid less reliable in the process.

"You've got a system that is based on power supply technologies that are overly dependent on renewables, which, because of their intermittent, weather-dependent nature, don't provide the kind of 24/7 reliability support that the customer really needs," Davis said.

Wind and solar do present some challenges, but Peskoe argued that they were not insurmountable and cautioned against "techno-pessimism."

"And I would say that the far bigger subsidy, again, is vertical integration, which is a much bigger intervention in the market than any tax credit," he added. ■

BPA Sued in 9th Circ. over Day-ahead Market Decision

Five Groups Allege BPA Violated Federal Law by Choosing Markets+ over EDAM

By Henrik Nilsson

A group of nonprofits sued the Bonneville Power Administration on July 10 in the 9th Circuit Court of Appeals over the agency's decision to join SPP's Markets+ instead of CAISO's Extended Day-Ahead Market, saying the move will drive up costs and risk reliability in violation of federal statutes.

Represented by Earthjustice, the organizations asking the 9th Circuit to review and vacate BPA's record of decision (ROD) include NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board and the Sierra Club.

The group alleges BPA rushed into its day-ahead market decision without considering the environmental impacts of its decision. The agency also now risks increasing costs for customers while ignoring its obligations to prioritize conservation and renewable power.

The group asks the court to vacate the day-ahead market decision and brings claims under the National Environmental Policy Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the Administrative Procedure Act.

"Bonneville's decision on markets will affect the transmission and generation of electric power across the West and is exactly the type of major federal action that should first consider the harms it could cause to our air quality, grid system reliability, fish and wildlife, etc.," Jaimini Parekh, senior attorney with Earthjustice, said in a statement. "This is exactly why Congress enacted NEPA — to examine the consequences before acting. Here, however, the agency has completely ignored its obligations under federal law."

Why This Matters

The suit indicates the debate over BPA's day-ahead market decision is likely to continue as the industry navigates two major markets in the West.

The Bonneville Power Administration

The allegations will sound familiar to those who have followed BPA's day-ahead market process.

In a news release, the group cites an analysis by state agencies in Washington and Oregon using BPA's data that found the agency could have saved its customers $4.4 billion through 2035 by joining EDAM.

Those arguments follow a production cost study by Energy and Environmental Economics (E3) commissioned by BPA in 2024 that showed participation in EDAM could deliver the agency up to $106 million in greater benefits than Markets+. (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

Proponents of EDAM have pointed to the E3 study and another by The Brattle Group — not commissioned by BPA — that found by 2032, the agency could earn $65 million in benefits from participating in EDAM versus an $83 million net loss in Markets+. (See *Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW*.)

The suit argues that because EDAM provides a larger market footprint, BPA's customers will miss out on significant cost savings, improved energy reliability and greater access to clean energy resources. EDAM also is "more geographically contiguous, its market participants include more of Bonneville's historic trading partners and, consequently, the transmission system is better developed than is the case for Markets+," the group claims.

"Moreover, Bonneville's day-ahead market decision will likely require regional electricity providers to construct additional power generation facilities and/or increase operation of existing facilities, including natural gas, and coal plants, as a consequence of Bonneville's participation in the smaller and less efficient, less diverse Markets+," the suit states.

By joining Markets+, BPA also is leaving CAISO's Western Energy Imbalance Market (WEIM) and will lose the benefits of participating in that real-time market, the organizations say.

Meanwhile, BPA has argued consistently its day-ahead markets process has been conducted with significant stakeholder input, noting in its final market decision issued in May that other electric utilities that have taken steps to join either Markets+ or EDAM have done so "without public process or transparency." (See *BPA Chooses Markets+ over EDAM*.)

As for the production cost studies, the

Continued on page 15

BPA Outlines Proposed Transmission Planning Reforms

By Henrik Nilsson

The Bonneville Power Administration has unveiled its proposals for overhauling its transmission planning, with help from the industry.

BPA in February paused certain transmission planning processes to consider new reforms in light of significant growth in transmission service requests. The agency's 2025 transmission cluster study includes more than 65 GW of requests, compared with 5.9 GW in 2021. The requests exceed the total regional load predicted for the Pacific Northwest in 2034, according to the agency. (See *BPA Halts Some Tx Planning Processes Amid Service Requests*.)

During a July 9 workshop, BPA outlined its plan for tackling the queue and ultimately reforming its processes to reach the agency's vision of reducing the time from transmission request to service to five to six years. (See *Industry Sees Challenges as BPA Considers 'Radical' Updates to Tx Planning*.)

For example, the agency is considering implementing readiness criteria and a new Network Integration Transmission Service initiative where any new forecast increase of 13 MW or more during any year would require participation in commercial planning.

"If you can't meet the readiness requirements, you leave the queue, and we keep funneling it down until we get to a place where in our long-term firm queue management, we've either offered you transmission service on a firm basis, we've offered it on a conditional firm basis or some other less than firm," said Abbey Nulph, manager of transmission commercial planning at BPA.

Why This Matters

The proposed overhaul of BPA's transmission planning processes showcases the many challenges data centers and other energy intensive projects pose to the system.

"Our goal is to make as many offers to those that remain as we can so that folks are getting service, potentially not the long-term firm that everybody wants, but the best that we can without degrading the quality of service for existing rights holders," Nulph added.

The agency also is contemplating offering interim service and moving toward proactive planning, meaning building ahead of transmission service requests, according to the workshop presentation.

BPA told *RTO Insider* in a statement that proactive planning "is a 20-year scenario-based power flow, capacity expansion and production cost modeling study, performed with robust stakeholder engagement, that will give BPA the vision to identify the evolving transmission needs within our area."

"This study will operate on a two- [to] three-year cycle and will feed an evolving transmission expansion and reinforcement project portfolio for which BPA will establish a transparent project selection process," according to the statement. "The planning scenario will be based on a set of models ranging from capacity expansion to NERC planning standard-based power flow studies."

The agency received support for its framework from stakeholders participating in the meeting. One representative from the Columbia River PUD said the "proactive planning makes a lot of sense because it gives us the ability to take a holistic view of a community and for you to do the same thing when you make your decisions. It's not just about a company but really looking at the opportunities and what's going on in the community."

However, some also raised concerns about recent staffing cuts at the agency and how the costs associated with the reforms will affect ratepayers.

Fred Heutte, senior policy associate at the Northwest Energy Coalition, said in an interview he supports BPA's initiative.

"We have a lot more extreme weather. We have a big heat wave coming here next week during a low hydro period," Heutte said. "We do need more transmission to bring on the … more diverse set of

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resources so we can keep the grid going. And so I really feel like BPA has put good principles on the table."

Still, Heutte said BPA must ensure customers have fair access to new transmission rights and that the new readiness criteria are flexible.

"There needs to be a real focus on transparency of how they're handling transmission requests and sorting them out through this new process that they're developing," Heutte said. He added that BPA needs to be "very clear about what their intended outcomes are and work closely with the customers and … with the state commissions."

During the July 9 workshop, Nulph pointed to these principles, saying the agency will focus on transparency and collaboration and provide insights into how it will "solicit information, which data inputs we use, which scenarios we run, how we select the projects that come out the other end of those studies."

"We don't want this to be a BPA plan," Nulph said. "We want it to be BPA's plan to satisfy the regional needs." ■

BPA Cuts Payments for Tribes, Salmon Restoration Under Revised Cost Projections

Agency Updates Projections Following Trump Memo Directing Withdrawal from Agreement

By Henrik Nilsson

The Bonneville Power Administration on July 14 said it is revising future power rates by removing millions of dollars of costs associated with a Biden administration agreement with Northwest tribes aimed at restoring salmon habitat and potentially breaching dams on the Snake River.

BPA Chief Financial Officer Thomas McDonald detailed the revised power cost projections for the BP-26 rate period in a *letter* dated July 11 following a Trump administration memorandum in which the president pulled the federal government out of a deal Biden struck with Oregon, Washington and four tribes on four dams along the Snake River in 2023. (See *Trump Directs Feds to Withdraw from Deal on Snake River Dams*.)

The deal included payments to the Yakama, Umatilla, Warm Springs and Nez Perce tribes, along with Oregon and Washington. The costs were reflected in BPA's program forecast issued Oct. 23, 2024. The forecasts serve as an input into the development of rates, according to the letter.

Under the new forecasts, the agency predicts BPA power rates will see a "slight decrease," a spokesperson told *RTO Insider*.

However, under the updated power cost projections, those payments are removed, including \$10.6 million for 2026, \$10.8 million for 202 and \$11 million for 2028

Additionally, the agency removed cost projections related to the Lower Snake River Compensation Plan, a hatchery program to return salmon and steelhead to the Snake River Basin.

The removed cost projections associated with that plan include \$11.7 million for 2026, \$19.4 million for 2027 and \$28.2 million for 2028.

McDonald noted in the memorandum that removal of the plan cost projections "will not result in a dollar-for-dollar reduction in BPA's costs."

"The Lower Snake Compensation Plan hatchery costs were included as part of BPA's capital cost projections, which means that the annual spending is recovered over time rather than in the year it is spent," McDonald added. "The cost savings will appear as lower interest expense, amortization expense and principal payments."


BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

Why This Matters

BPA's move provides further evidence of how quickly the Trump administration is reversing the policies of its predecessor.

President Donald Trump issued the memo June 12 withdrawing from the 2023 deal that was struck after lengthy litigation about four tribes' rights to fish in the river. The deal was opposed by other interests in the region including senior Republicans in Congress. (See *Parties Split on Biden Administration Deal on Snake River Dams*.)

The deal supported federal investments in a comprehensive plan for salmon restoration, energy development and transportation infrastructure in the Columbia Basin, according to a previous press release from the Confederated Tribes and Bands of the Yakama Nation.

The Biden administration was considering breaching four dams that produce more than 3,000 MW, but had not made a final decision.

The Department of Energy said the Biden-era memo of understanding (MOU) required the government to spend \$1 billion to comply with commitments aimed at replacing the dams in the Lower Snake River, including possibly breaching them.

The June 12 memo directs cabinet secretaries to work to withdraw from the deal and to rescind a supplemental environmental impact statement on the four dams that was published in December 2024. ■

PGE Ponders Role of Batteries in Resource Plan Update

Costs of Eliminating Renewable Tax Credits also Considered

By Elaine Goodman

Portland General Electric's need for more resources by 2030 has grown by 16%, according to updated modeling, largely due to a decreased capacity contribution from batteries, particularly in winter.

The figures are in an *update* to PGE's 2023 integrated resource plan (IRP) the utility presented to the Oregon Public Utility Commission (OPUC) on July 8.

Updated modeling led to changes in PGE's preferred resource portfolio, which includes 4,629 MW of new resources by 2030 compared to 3,984 MW in the 2023 IRP — a 645-MW increase.

While the amount of resources such as wind and non-emitting energy contracts decreased in the updated portfolio, the biggest change was the addition of 881 MW of battery storage.

Why This Matters

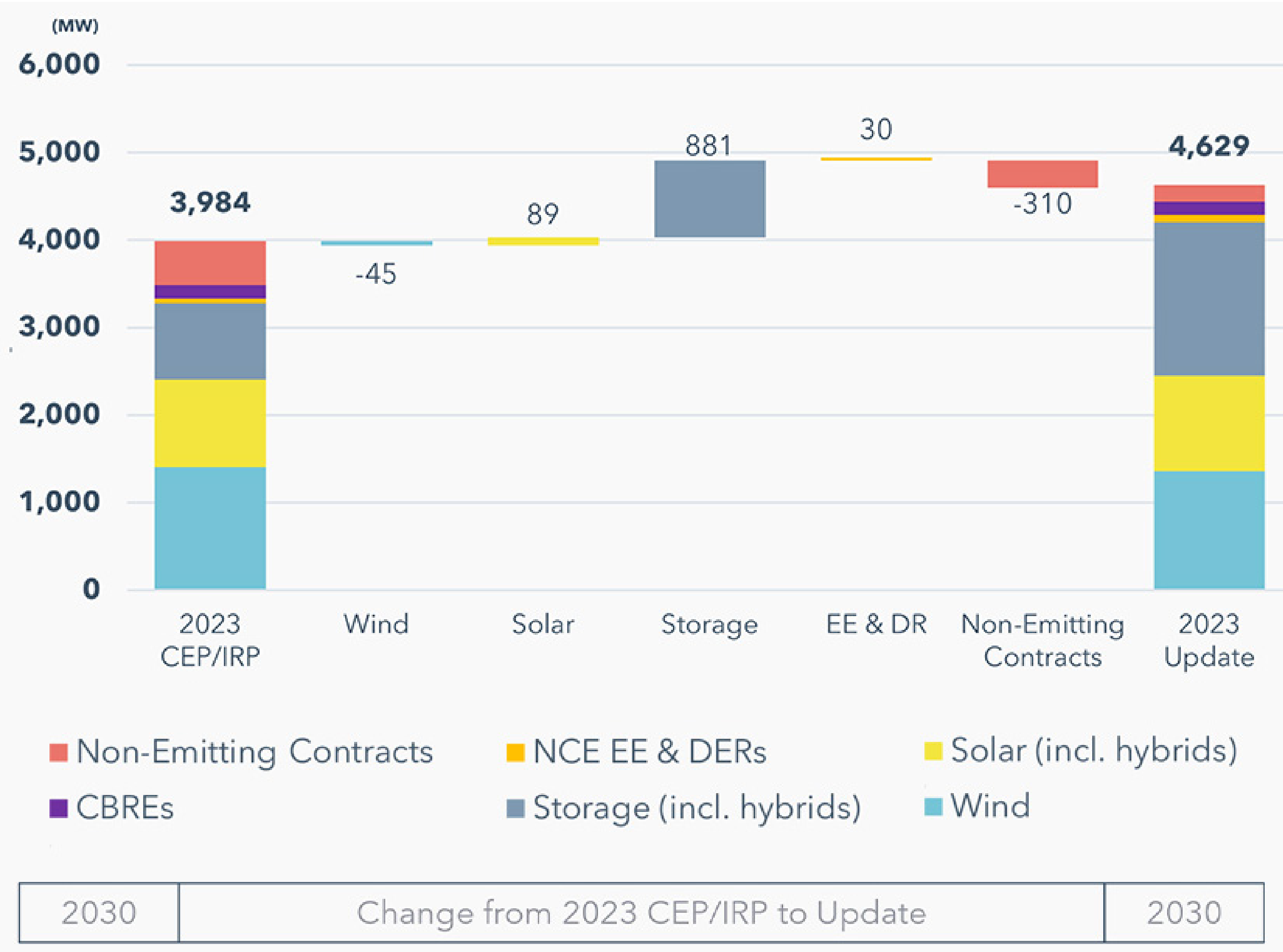
The resource plan update comes as PGE is seeing unprecedented industrial load growth from data centers and semiconductor manufacturing.

New modeling in the IRP update found the effective load carrying capability for four-hour battery storage would be 46% in summer and 22% in winter — compared to roughly 70% in summer and 45% in winter modeled in the 2023 IRP for 100 MW of nameplate capacity.

"The reduced capacity contribution of storage resources, particularly in winter, highlights a critical planning challenge regarding the interaction between storage and energy resources in a system with growing demand and thus energy deficits," the IRP update states.

Jimmy Lindsay, director of resource planning at PGE, attributed the decreased capacity contribution in part to "a saturation issue," as the utility is planning "a significant quantity" of four-hour lithium-ion batteries in its portfolio.

But he said another factor is increased load forecasts during the winter, when



PGE has updated the resource additions in its preferred portfolio for 2030 compared to those in its 2023 integrated resource plan. | *PGE* demand can surge for several days in contrast to shorter peaks in the summer.

"That is an issue that we had anticipated would emerge … that the models weren't necessarily capturing the challenge around recharging on a multi-day event," OPUC Chair Letha Tawney said.

The IRP update said it didn't look at including long-duration storage in the preferred portfolio "due to the lack of commercially proven projects." Long-duration storage will be explored further in the 2026 IRP.

The presentation was informational only; PGE is not seeking formal acknowledgement of its update from the commission.

Tax Credit Implications

Existing plus new resources in the updated preferred portfolio total about 10,000 MW in 2030, about double the amount of resources in 2026. A large jump in resources is expected in 2029, as resources procured through requests for proposals come online.

Another jump in resources is expected in 2032, when new transmission will support imported power.

In particular, PGE is working with the Confederated Tribes of Warm Springs on a 500-kV upgrade of the 230-kV Bethel-Round Butte line. They secured a $250 million Grid Resilience and Innovation Partnerships program grant from the U.S. Department of Energy that will allow survey work to begin.

Another challenge for PGE is changes in federal policy — and the cost impacts to the utility's renewable energy transition. The elimination of federal tax credits could increase renewable costs by 30% to 50% or even more, according to the IRP update.

Most recently, tax credits were targeted in an executive order President Donald Trump issued July 7. (See *Trump Executive Order Targets Renewable Energy Tax Credits*.)

"The change in the federal landscape cannot be underestimated," said Kristen Sheeran, PGE's vice president of policy and planning.

Rapid Industrial Growth

The IRP update predicts a 20-year average annual growth rate of 2.8%, an increase from the 1.2% growth rate forecast in the March 2023 IRP. For industrial customers, the 20-year average growth rate now is expected to be 5.2% a year, compared to 3.5% in the 2023 IRP.

"Growth is driven primarily by unprecedented industrial sector expansion, especially in semiconductor manufacturing and data centers," PGE said in the update.

After the PGE update was released, chipmaker Intel, Oregon's largest private employer, *announced* it was laying off almost 2,400 of the 20,000 employees in the state as the company struggles to remain competitive. Intel's operations in Hillsboro are served by PGE. It's unclear what effect Intel's difficulties might have on future load growth.

PGE hit a record summer peak load of 4,498 MW in August 2023 and a record winter peak of 4,113 MW in December 2022.

The IRP update projects a summer peak of about 5,500 MW in 2030 and 8,000 MW in 2044, taking into account electrification of vehicles and buildings. Winter peak is expected to grow to about 4,500 MW in 2030 and 7,000 MW in 2044. ■

BPA Sued in 9th Circ. over Day-ahead Market Decision

Continued from page 11

agency has contended those studies failed to factor in other key issues, like governance. BPA says the SPP market's governance structure is "superior" to that of EDAM, despite ongoing efforts by the West-Wide Governance Pathways Initiative to relax the state of California's oversight for CAISO's EDAM and WEIM.

Still, the plaintiffs in the underlying suit claim BPA has prioritized governance over other obligations the agency is required to consider under law, such as protecting wildlife and promoting renewable energy.

The organizations also bring up the seams likely to arise after the launch of the two separate day-ahead markets, claiming BPA is contributing to the creation of artificial barriers to trade that will require complex negotiations between parties to ensure effective trade can continue.

However, BPA staff have noted throughout various public meetings that the agency is not solely responsible for creating seams and already manages a non-contiguous balancing authority area that spans six states that is adjacent to 18 other BAAs. BPA staff also noted the agency has more than 75 years of experience managing operations across seams, while acknowledging that day-ahead markets will add a new layer of complexity.

Reaction was swift:

"BPA's decision to join Markets+ is inconsistent with its responsibility to maximize customer benefits in accordance with sound business principles," said a statement released by Seattle City Light and attributed to Dawn Lindell, CEO and general manager. "Seattle City Light is deeply disappointed in the agency's decision. BPA's own record and analysis shows that Markets+ will increase costs for BPA and its customers. At a time when City Light and other utilities throughout the region are working to contain rising costs to meet growing energy needs, BPA's disregard for the economic impacts associated with its day-ahead market decision is alarming. Our ratepayers will bear the burden of this decision as it increases energy costs $20 million to $40 million every year."

When asked for a response, BPA said it doesn't comment on active litigation.

SPP released a statement from Carrie Simpson, vice president of markets: "SPP is aware that a legal challenge has been filed regarding Bonneville Power Administration's decision to participate in Markets+. We remain confident in the integrity of BPA's decision-making process but respect the right of all stakeholders to have their concerns heard, and we trust the judicial process to appropriately consider the issues raised. We stand committed to working with BPA and others across the West to deliver reliable, efficient, and transparent market solutions that benefit the entire region." ■

FERC Launches Section 206 Proceeding for Idaho Power

By Henrik Nilsson

Idaho Power must prove it does not have unjust market power in its balancing authority area, FERC ruled July 8.

Idaho Power failed the wholesale market-share indicative screen for its balancing authority area (BAA) in three of four seasons for the December 2022 to November 2023 study period. FERC presumes the existence of horizontal market power when a seller fails a screening.

FERC said it will launch a Section 206 proceeding under the Federal Power Act "to determine whether Idaho Power's market-based rate authority in the Idaho Power balancing authority area remains just and reasonable and to establish a refund effective date."

On April 25, 2025, Idaho Power reported a notice of change in status to report a 230-MW increase in its generation capacity in its BAA. The filing included market power analyses for eight BAAs, including its own.

Despite the screen failure, Idaho Power argued in its filing that a price test indicates it does not have market power.

However, FERC said "we conclude that Idaho Power's failures of the non-summer market share indicative screens provide the basis for the commission to institute the instant Section 206 proceeding."

"As the commission has previously stated, sellers submitting evidence, such as a delivered price test, in support of a contention that they do not possess market power should not expect that the commission will postpone instituting a Section 206 investigation while it examines the supplemental information," the order stated.

Idaho Power headquarters in Boise | *Idaho Power*

Idaho Power has 60 days to show why FERC should not revoke its market-based rate powers in its BAA. The utility also can file supplemental evidence like "historical sales and transmission data to rebut the presumption that it has the ability to exercise horizontal market power in the Idaho Power balancing authority area," according to the order.

Alternatively, Idaho Power can file a proposal that would mitigate its market power or "inform the commission that it will adopt the commission's default cost-based rates or propose other cost-based rates and submit cost support for such rates."

FERC expects to issue a decision by Jan. 7, 2026.

Idaho Power is an investor-owned utility based in Boise. It serves an area of about 24,000 square miles in Idaho and Oregon and relies on hydroelectric power for much of its energy mix.

It reported that its control of generation in the Idaho Power BAA increased in May as it began service under a long-term firm power purchase tolling agreement that allows the utility to charge and discharge the output of Kuna BESS LLC's 150-MW (600 MWh) battery energy storage system. The PPA runs through May 19, 2045.

In June, the utility's Happy Valley BESS, an 80-MW (320 MWh) standalone BESS, started operations. ■

CAISO Looks to Improve Visibility of Distributed Battery Storage

By David Krause

CAISO is working on an initiative to improve the visibility of distributed battery storage resources on the grid, especially for when they are needed for resource adequacy purposes.

The additional information will allow operators to see potential real-time operational limits of the resources on the distribution system, CAISO said in a June 30 *presentation*.

Part of the challenge is that distributed batteries are often operated by a local utility, which might request placing certain charging and discharging restrictions on them. Sometimes that request conflicts with CAISO's request for the same resource. When this happens, a battery resource should follow CAISO's request, unless human safety or electric facilities would be knowingly put at risk, the ISO said in a *discussion paper*.

Another challenge for CAISO is figuring out how charging constraints are affecting distributed batteries during dispatch times. For example, if a storage resource is restricted from charging in the afternoon, then it might not be able to discharge to its full capacity in the evening, the paper says.

Why This Matters

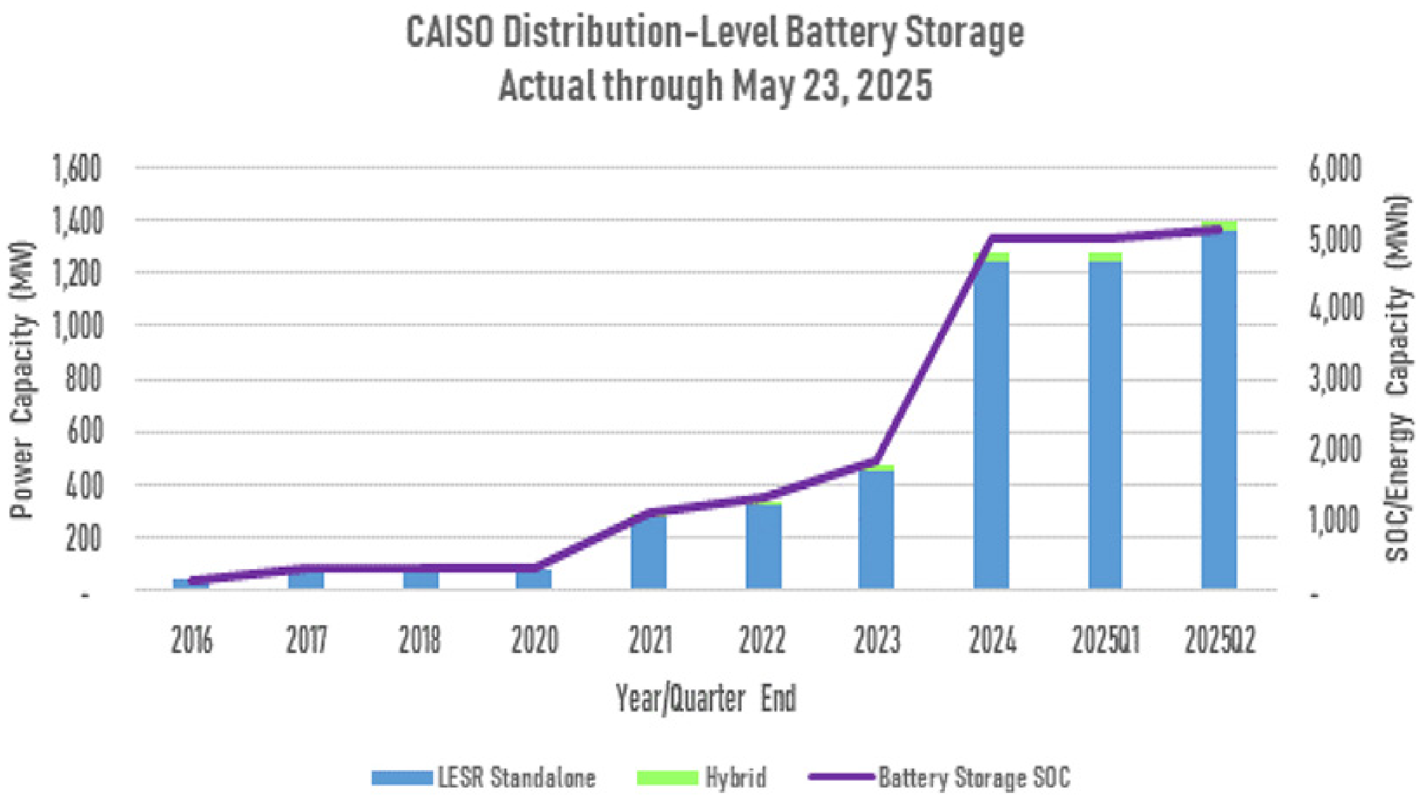
Battery storage in California is growing extremely fast, and CAISO needs to see how the resource is behaving.

To address this problem, CAISO could identify distributed units in its master data file using a specific flag, the paper says. This approach would provide a good first step in providing needed transparency and was supported by two stakeholders in the initiative, the paper says. However, six stakeholders preferred updating CAISO's resource modeling tools, such as its real-time telemetered capabilities, and extending the dynamic limit tool, the paper says.

In California, distributed battery storage capacity has grown from about 330 MW in 2022 to about 420 MW in 2023 and nearly 1,400 MW in 2025. It has not grown much over the past year, however: Capacity was about 1,250 MW in 2024.

As part of the same initiative, CAISO is studying the availability of mixed-fuel resources, such as solar and battery storage facilities, on the grid. Currently, the ISO is struggling to obtain accurate and reliable data from mixed-fuel resources, specifically about a resource's high sustainable limit (HSL). The HSL is an estimate of the instant generating capacity of a variable energy resource. For this problem, CAISO proposed to evaluate how HSLs are developed in its Business Practice Manuals. Doing so could improve short-term forecasts of co-located and standalone variable resources, the paper says.

Comments on the paper are due July 16. ■



| CAISO

Texas Public Utility Commission Briefs

Regulators Approve SPS, SWEPCO System Resiliency Plans

The Texas Public Utility Commission has approved system resiliency plans for Southwestern Public Service and Southwestern Electric Power Co. (SWEPCO), as it continues to meet a requirement from the 2023 legislative session.

Both plans were the result of agreements with intervening parties. SPS, an Xcel Energy subsidiary, reached a settlement over its three-year plan with the Office of Public Utility Counsel (OPUC), Alliance of Xcel Municipalities, Texas Industrial Energy Consumers (TIEC), Walmart, the International Brotherhood of Electrical Workers Local Union 602, Golden Spread Electric Cooperative and PUC staff (*57463*).

The *SPS plan* includes distribution overhead hardening, distribution system protection modernization, communication modernization and wildfire mitigation. The utility proposed $538.3 million of investments to be implemented from 2025 to 2028.

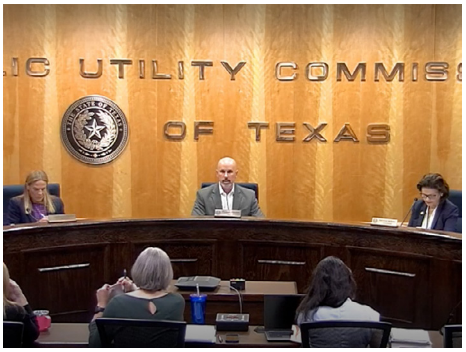
The settlement removed the five lowest benefit-cost ratio projects from the distribution overhead hardening measure, totaling $5.9 million by the agreement. However, the commission agreed to reinstate the projects, saying they also were designed to strengthen overhead infrastructure to prevent, withstand and mitigate wildfire risks.

In February 2024, downed power lines from a broken SPS utility pole ignited the *Smokehouse Creek Fire* in the Texas Panhandle. It became the largest wildfire in recorded state history, burning more than 1 million acres before being contained.

"Given where this is and the recent history in the area, I think adding those measures back in makes sense to me," PUC Chair Thomas Gleeson said during the commission's July 10 open meeting.

Xcel has acknowledged its role in the fire and has *settled 151 out of 225 claims* filed through a dedicated claims process.

SWEPCO's plan was included on the PUC's consent agenda. The American Electric Power subsidiary reached a unanimous agreement in March with commission staff, OPUC, Cities Advocating Reasonable Deregulation, TIEC and Walmart. The commission modified the plan to remove several "enhanced vegetation management" measures with benefit-to-cost ratios below 1.0, reducing its estimated cost from $88.9 million to $83.7 million (*57259*).



Texas regulators discuss system resiliency plans during their July 10 open meeting. | *AdminMonitor*

The four-year plan also includes distribution feeder and lateral hardening, and increased distribution automation circuit reconfiguration.

The 2023 Texas Legislature's *House Bill 2555* allows the state's electric utilities to file resiliency plans for approval with the PUC. The plans must include measures that would "help the utility prevent, withstand, mitigate or more promptly recover from resiliency events, which include extreme weather, wildfires, and cybersecurity or physical security threats."

Oncor was the first utility to secure approval of its resiliency plan in November 2024. (See *Texas PUC Approves 1st System Resiliency Plan*.)

Wildfire Mitigation Plans

The commission established a July 25 deadline for utilities, municipalities and cooperatives that own transmission and distribution facilities to provide input on PUC rules for wildfire mitigation plans, as required by a *new state law* (*56789*).

"I know it's a short timeline, but please provide … your input," Gleeson said. "As you hear us say often up here, the best outcomes happen when we get as full participation as possible, so please avail yourselves of this opportunity to provide input to commissioners."

Staff plan to bring a formal proposal for publication to the PUC's Aug. 21 open meeting.

Status Quo for FFSS Program

After consulting with the grid operator and its Independent Market Monitor, PUC staff have *proposed* maintaining the same parameters for ERCOT's *firm fuel supply service* (FFSS) program during the winter 2025/26 contract period. That will retain the program's $54 million budget, $12,240/MW offer and 48-hour deployments (*56000*).

The program has procured 3,319 MW and 4,194 MW in its first two years, at a cost of $29.4 million and $42.4 million, respectively.

Staff plan to gather feedback from ERCOT, the IMM and stakeholders to develop rule language before future contract periods, allowing the commission to consider next phase options before the 2026/27 winter.

The FFSS program provides additional grid reliability and resilience in the event of fuel disruptions during extreme cold weather, compensating generation resources that meet a higher standard.

SB6 Workshop July 21

The PUC has scheduled a workshop for July 21 to gather public and stakeholder input as it prepares to implement *Senate Bill 6*.

The "seminal piece of legislation" from the 2025 biennial session, as Gleeson described it, directs the commission to determine a cost allocation for large loads to ensure they pay their fair share of infrastructure expenses and requires their developers to pay a $100,000 fee for the initial screening studies (*58317*).

Gleeson said it will be important to standardize how load is counted for transmission purposes and to focus on the bill's co-location and net-metering agreements. He urged staff to work with ERCOT staff on transmission and resource adequacy issues. ■

— Tom Kleckner

IESO Officials Deny Favoring Gas Resources in Upcoming Procurement

ISO Promises Deal on Grid Interconnection Costs

By Rich Heidorn Jr.

Potential energy suppliers in IESO's second long-term energy and capacity procurement (*LT2*) sparred with ISO officials July 10, saying its proposed auction rules favor natural gas generators by insulating them from most of the cost of gas transmission upgrades.

In a *webinar*, the ISO said it would reimburse gas generators 75% of upgrade costs "to address natural gas transmission cost uncertainty." The auction rules also provide cost protections for all generators facing increased tariffs and allow gas generators to extend their commercial operation dates because of delays in obtaining gas turbines.

Mike Marcolongo, associate director of Environmental Defence, said the 75% reimbursement was "quite generous."

"I think that we have done quite a lot for all of the technologies that are that are eligible to participate in our [requests for proposals] over time," responded Dave Barreca, IESO's supervisor of resource acquisition. He cited the materials cost index adjustment the ISO has used in previous solicitations to address the fluctuating costs of lithium for battery providers.

Attorney Jake Sadikman — co-chair of Osler, Hoskin & Harcourt's national energy group, which is working with IESO on the procurement — also cited the "regulatory charge credit," which reimbursed battery storage for regulatory energy charges, including global adjustment.

Barreca said the ISO decided a 75% reimbursement was "an appropriate value … that would mitigate the risk sufficiently for a gas generator to be able to participate in the RFP while maintaining the incentive for them to mitigate — or, in fact, avoid — the costs."

Need for New Gas Generation

Brandon Kelly, director of regulatory and market affairs for Northland Power, said the ISO's approach could result in "inefficient outcomes" if the added cost makes a gas generator more costly than rejected bids.

Why This Matters

IESO officials said cost-sharing provisions are needed to ensure the province adds new gas generation.

"This is an imperfect outcome," Barreca acknowledged. "It's not what we would have necessarily wanted. But this is what we need to ensure that all resources are able to participate.

"We wouldn't be doing this if we didn't think that we need some amount of … new natural gas on the system to get us through the transition period over the next few decades," he added. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

"I can recognize that none of this will be perfectly efficient, but that is true for the rest of the RFP. There are a lot of constraints other than cost: on where sites are selected and what ultimately gets chosen. So we are, I think here, doing the best, given the constraints that we have."

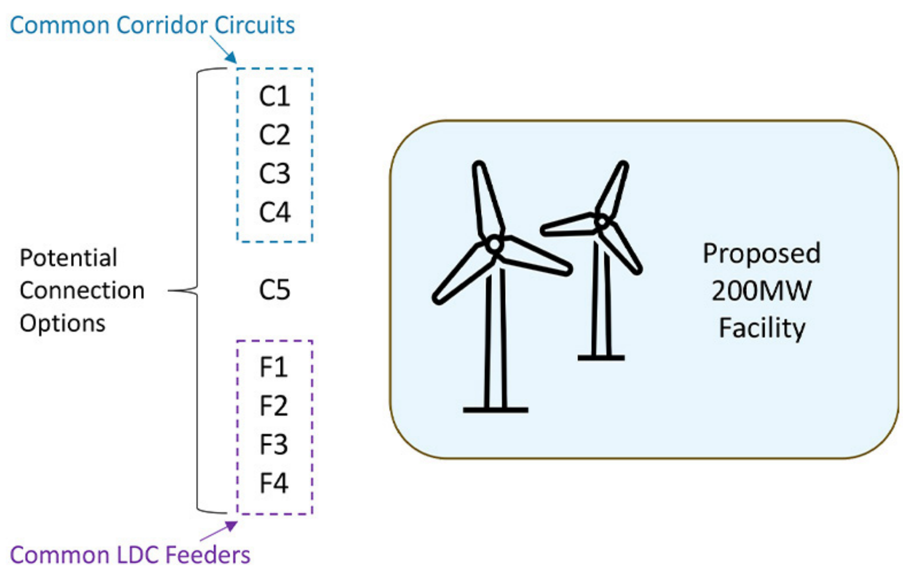
Kelly was unpersuaded. "What you've done here is not to … allow these resources to participate; it's to advantage them, and that's materially different from the approach you guys have taken elsewhere," he said. He suggested gas generators instead incorporate a risk premium in their offers.

IESO's Ben Weir said if the actual gas transmission connection costs ultimately approved by the Ontario Energy Board are less than the risk premium, "ratepayers end up covering that risk-adjusted premium for really no reason."

Uncertainty over Grid Interconnection Costs

Eric Muller, Ontario director of the Canadian Renewable Energy Association, said there also is great uncertainty on the costs of interconnections with the

Primary Proposal PQ	200MW on C5	100MW on C1 100MW on C4	50MW on C1 50MW on C2 50MW on C3 50MW on C4	100MW on F2 100MW on F3	100MW on C1 100MW on C5	100MW on C1 100MW on F1	99.75MW on C1 99.75MW on C2 0.5MW on C3



Proposals to IESO's LT2 procurement may specify connection to up to four circuits/feeders within a common corridor (green boxes) but cannot mix circuits and feeders or circuits in separate corridors (red boxes). | *IESO* electricity transmission system. He said the ISO should provide a cost-sharing or true-up mechanism to address those risks.

Barreca said the risks of electric interconnection costs are "materially different" from those for gas because of a new process that will allow Hydro One, the province's largest transmission operator, to give generators "perhaps not perfect [certainty] but at least enough certainty on those costs that they'll be able to confidently submit their bids."

"We continue to work hard with our colleagues at Hydro One on this issue and hope to be able to share something with you all in the very near future," Barreca said.

Officials said IESO will hold an engagement session with Hydro One on July 30 to provide an overview of the process for making new or modified connections to the grid.

Barreca said the ISO was unable to reach such certainty regarding gas distribution costs. "That ultimately just was not possible. And that is a kind of regulatory thing," he said.

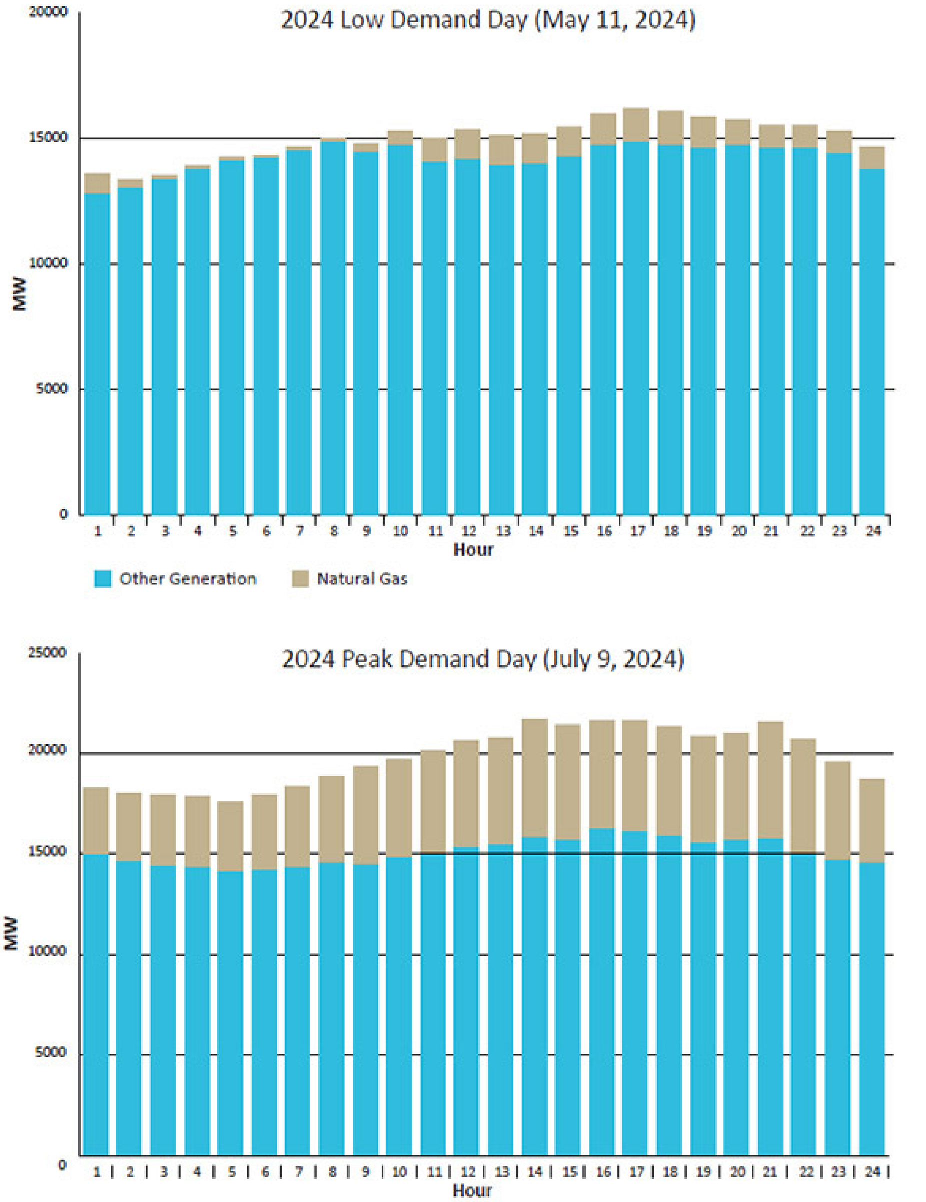
Tremor Temchin, senior vice president of development for Convergent Energy and Power, said the ISO's requirement that generators provide *continuous power for at least eight hours*; its "open-ended" commercial operation date for delayed turbine deliveries; and the cost sharing on gas distribution all look "like the ISO picking and choosing winners in a procurement that is supposed to be technology agnostic."

He suggested the ISO run a separate, gas-specific procurement, saying "it's the only way to keep this fair for other technology types."

"This is not the ISO trying to tip the scales in favor of one technology or the other merely to enable participation," Barreca responded. He said the move to an eight-hour minimum duration is "reflective of system needs and evolving system conditions."

He noted that the ISO has added nearly 3,000 MW of battery storage "in a very short period of time."

"The capacity value of that four-hour storage diminishes the more that you add without adding more … energy-



IESO says natural gas generation is essential to reliability on Ontario's hottest summer days. | *IESO*

producing resources," he said. Nevertheless, he said, the ISO has not sought to derate storage capacity.

"So, I really do not think that we are here trying to tip the scales in one direction or the other. We want to have as balanced and fair a procurement as possible. We very strongly believe in the value of a diverse supply mix, and that includes some of everything."

14 TWh, 1,600 MW Sought

IESO *announced* in December that it was seeking up to 14 TWh of annual generation and up to 1,600 MW of capacity resources in its second long-term procurement. The first window seeks 3 TWh of energy and 600 MW of capacity.

The ISO released final documents June 27 for the first window of LT2 *energy* and *capacity* procurements. Energy proposals will be due Oct. 16 and capacity proposals due Dec. 18, with notifications of winners set for April 14, 2026, and June 16, 2026, respectively.

The LT2 documents include updates to some terms to reflect IESO's May 1 introduction of a financially binding day-ahead market and the elimination of the State of Charge Reduction Factor, a transitional mechanism used to address storage facilities' need to withdraw real-time market (RTM) offers after depleting energy during RTM obligations. With its

Milestone	LT2 (e-1)	LT2 (c-1)
Final Documents Released	June 27, 2025	June 27, 2025
Deadline for Questions and Comments	July 24, 2025	August 21, 2025
IESO's Deadline for issuing Addenda	August 14, 2025	September 11, 2025
Registration Deadline	September 4, 2025	October 3, 2025
Proposal Submission Deadline	October 16, 2025	December 18, 2025
Target date for notification to Selected Proponents	April 14, 2026	June 16, 2026

Timelines for the first submission window of IESO's second long-term energy and capacity procurement (LT2) | *IESO*

new forward market, the day-ahead market no longer includes RTM, eliminating the dual obligation. (See *Ontario Introducing Nodal Market May 1*.)

The new procurement also gives bidders based in Canada a 2% reduction to their "evaluated proposal price."

IESO Senior Adviser Nick Topfer said the home-field advantage was added in response to a *June 26 directive* from the Ministry of Energy and Mines and will be additive — not diluting existing bonuses such as for Indigenous participation. The new solicitation also will allow bidders to seek price increases if import tariffs imposed after the proposals are submitted "directly" increase capital costs by more than 10%.

The ISO will have 50 days to respond to a "tariff adjustment notice" — down from 100 days, as originally proposed. If it rejects the revised price, the contract will be terminated, and the bidder's completion and performance security will be returned.

IESO has eliminated from the capacity solicitation a proposal to limit capacity check tests to a maximum of 15 degrees Celsius.

"This decision … was a bit premature and was made hastily by us," IESO's Sanjiv Sohal said. "It didn't wholly consider other articles contained in the contract. So as a result, we're walking this decision back, and the maximum temperature limit for the winter months in section 15.6 of the *contract* has not been removed."

The contract requires the tests to be conducted when temperatures do not exceed 35 C in the summer or fall below 20 C in the winter. ■

NEPOOL Market Committee Briefs

ISO-NE continued work with stakeholders on its capacity market overhaul at NEPOOL Markets Committee meetings, giving updates on its proposals for generator retirements, market power mitigation, and resource qualification and reactivation.

Deactivations

ISO-NE has *modified* its proposed timeline for resource owners to notify the RTO of resource retirements, cutting the notification lead time from two years prior to the capacity commitment period (CCP) to just one year. In the forward capacity market, resource owners historically have been required to submit retirement notices about four years prior to the relevant CCP.

The change came in response to stakeholder feedback that a lengthy lead time for retirement notifications could create risks of premature retirements.

"Some stakeholders wondered whether a shorter, irrevocable notice [would] provide more certainty to the market," said Kevin Coopey, principal analyst at ISO-NE. He added that Potomac Economics, the RTO's External Market Monitor, "voiced concerns with a comparatively long notification lead time and the lack of revocability."

He said a shorter timeline "allows resources to consider as much relevant information as possible, maintaining as much option value as possible, hence improving the probability of efficient deactivation decisions."

Under the proposal, retirement submissions would be binding, though resource owners would have the option to accelerate retirements.

While some stakeholders have pushed the RTO to allow resource owners to rescind retirement notifications in some circumstances, ISO-NE said revocability could lead to "numerous thorny issues," including coordination of transmission upgrades triggered by the resource deactivation and the release of capacity for interconnecting resources.

"The shorter notification lead time achieves most of the benefits of allowing revocability while being significantly simpler in scope and execution," Coopey said.

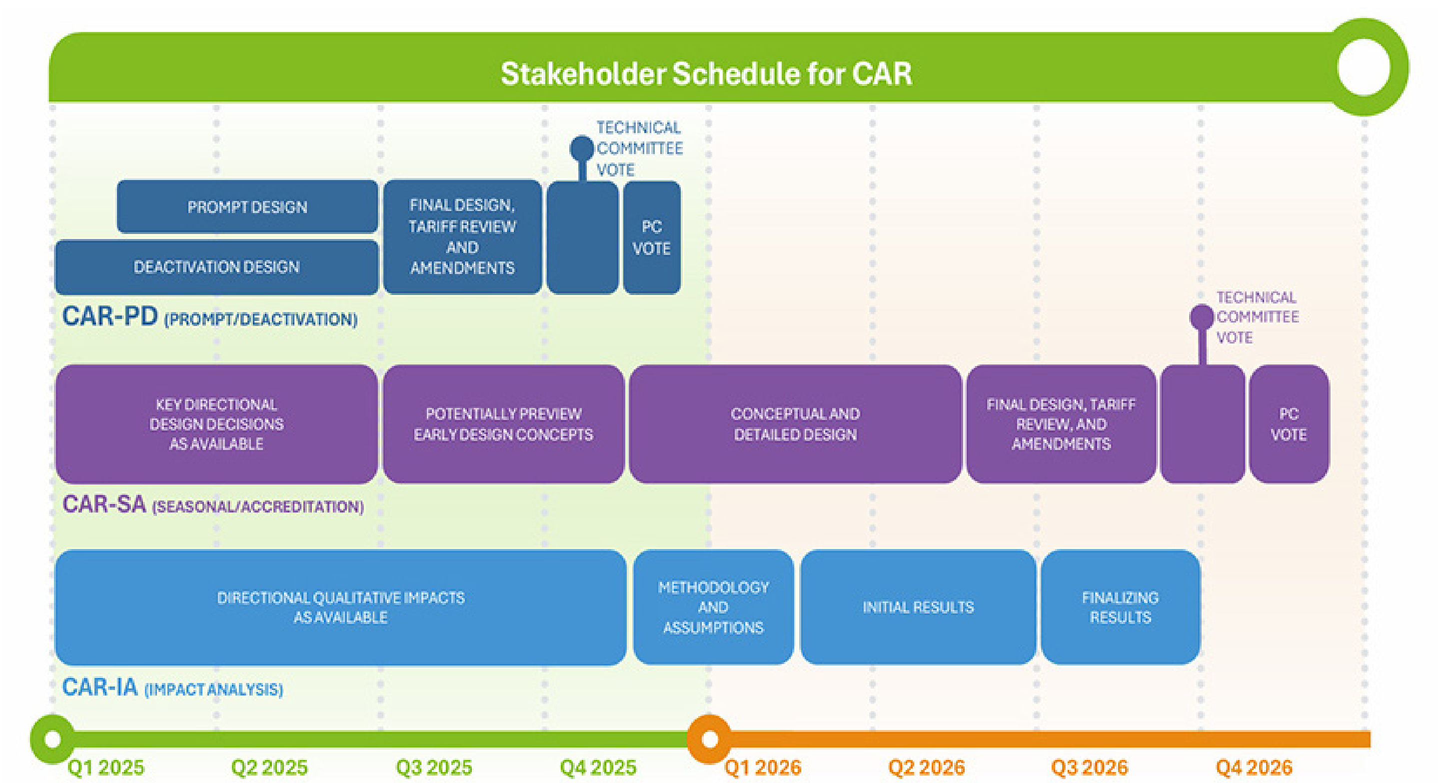
Bilateral Trading

ISO-NE *does not plan* to include the development of new bilateral markets or changes to monthly reconfiguration auctions in the capacity auction reform (CAR) project, said Chris Geissler, director of economic analysis at the RTO. He said efforts would require a "considerable body of work that would jeopardize the ability to deliver the core changes" in time for the 2028/29 CCP.

He added that the RTO expects the move to a prompt and seasonal capacity market to create new opportunities for bilateral trading.

Some stakeholders have expressed interest in the development of new ISO-NE-administered voluntary forward markets, along with the introduction of sloped demand curves to monthly reconfiguration auctions to allow different amounts of capacity to be sold for each month.

Geissler said the RTO may consider both initiatives after the CAR project is



ISO-NE capacity auction reform stakeholder schedule | *ISO-NE* completed.

Market Power and Mitigation

Also at the meeting, ISO-NE responded to feedback from the June MC meeting about the proposed approach to market power mitigation in a prompt auction. (See "Market Power Mitigation," *ISO-NE Internal Market Monitor Weighs in on Capacity Market Changes*.)

At the June meeting, the ISO-NE Internal Market Monitor recommended ISO-NE replace its pivotal supplier test with a "conduct and impact test framework," making the case that the pivotal supplier test could cause the "over-mitigation of resources" as the balance of supply and demand tightens.

Andrew Copland, economist at ISO-NE, said at the July MC meeting that the RTO still plans to include the pivotal supplier test in its prompt market tariff changes, adding that "developing a new mitigation framework falls outside the scope" of the CAR project.

He said ISO-NE plans to "conduct a more general evaluation of mitigation in the capacity market after completing the CAR project."

Copland also *provided details* on the cost workbooks that suppliers are required to submit to show the costs included in their capacity offers and the use of an IMM offer floor price to mitigate buyer-side market power.

Resource Qualification

In a prompt capacity market, ISO-NE *plans* to hold resource qualification activities "as close as possible to the annual auction and monthly trading activities to increase opportunities for new projects to participate," said Matt Brewster, senior manager of capacity requirement and qualification at ISO-NE.

For new resources, this will require the RTO to end its practice in the forward capacity market of monitoring the progress of non-commercial projects that have gained capacity supply offers.

Brewster said ISO-NE plans to continue its existing critical path schedule (CPS) monitoring approach until June 30, 2028. After that deadline, ISO-NE would return non-commercial capacity financial assurance for non-commercial resources that cleared in FCA 18 and non-commercial resources that cleared in earlier FCAs if their "CPS milestones are substantially complete."

It would not return the financial assurance if a resource triggers termination before the deadline or is not meeting its CPS milestones.

Some stakeholders expressed concern that this approach could incentivize non-commercial resources that otherwise would withdraw to refrain from doing so until after the deadline.

For in-service resources, Brewster said ISO-NE still is considering adjustments to the resource audit requirements and how to estimate qualified capacity for resources with limited data on their performance.

The audit requirements in the new auction framework would be based on resource class and intended to determine a resource's qualified capacity and verify it is in service.

Resource Reactivation

For retired resources, ISO-NE *proposes* removing the investment requirement for resource reactivation and requiring cost-of-service agreements retaining retiring resources to include "claw back" provisions which would take effect if a resource re-enters the market after its COSA expires.

"In all other ways, a reactivation project would have the same interconnection, qualification and mitigation review treatment as any other new resource for entry and participation in the market," Brewster said.

Brewster noted that the existing investment requirement may deter re-entry or encourage unnecessary investments to meet the threshold and added that eliminating the investment requirement would "support the potential cost-effective and timely re-entry of previously deactivated resources."

Meanwhile, requiring claw-back provisions in COSAs would prevent incentives for resources owners to fish for out-of-market resource retentions, Brewster said.

Next Steps

The RTO plans to present tariff changes for its qualification rules, annual auction mechanics, market power mitigation requirements and resource deactivations at the MC in August. It aims to vote on the changes in October and submit the filing to FERC before the end of the year.

The second phase of the CAR project, focused on seasonal auction changes and resource accreditation, will continue throughout 2026. ■

— Jon Lamson

Southern Renewable Group Cautions State Regulators Considering SEEM

SREA Says SEEM's Savings not Worth RTO Exit

By Amanda Durish Cook

The Southern Renewable Energy Association appeared before Entergy's state regulators to urge them to think twice before considering leaving MISO for the Southeast Energy Exchange Market.

Simon Mahan, executive director of the SREA, told attendees at a July 11 Entergy Regional State Committee Working Group that SEEM doesn't appear capable of delivering the savings of MISO or SPP.

Mahan said SEEM averages 80,000 MWh in monthly transactions. He said while that sounds like a lot, SEEM's annual amounts are equivalent to a 300- to 500-MW solar farm, with less than 0.1% of all bilateral trades in the Southeast conducted through SEEM.

Entergy Louisiana transmission work around Lake Charles in 2023 | *Entergy*

Mahan said, "for a region as big as SEEM," which has more demand than MISO, the numbers are minuscule.

"So, we're talking about a very, very small market and very little impact on how the utilities [operate] on a day-to-day basis," Mahan said. "There are 99.9% more bilateral trades already going on in the Southeast without SEEM."

Mahan said SEEM's estimated $1 million per month in gross savings over 2025 excludes all the parties that need to be paid: Hartigen as market platform provider; Potomac Economics for monitoring; Mahan McGuire Woods for legal fees; and various utility positions dedicated to monitoring the marketplace.

"The total benefit we're looking at here is far below the $40 million estimate provided to FERC a few years ago," Mahan said. "If you join SEEM, you're going to lose a significant number of benefits."

Mahan said while SPP (95 GW of installed capacity) and MISO (198 GW of installed capacity) estimate their total value to members at $2.14 billion and anywhere from $3.1 billion to $3.9 billion, respectively, SEEM (representing 160 GW) appears poised to deliver just $12 million in annual savings.

By contrast, Mahan said savings conferred to Entergy Louisiana alone for one year of MISO membership are about $79 million/year (La. PSC docket X-36326). Cleco, meanwhile, is primed to save about $112 million from 2025 to 2027, a 13% savings over leaving MISO (La. PSC docket X-36327), Mahan said.

Entergy associate general counsel Matt Brown confirmed that the $79 million savings take into account the MISO administrative costs.

Mahan's presentation comes as one Louisiana regulator wants the South to defect to SEEM.

Louisiana Public Service Commissioner Eric Skrmetta wrote an *opinion piece* updated July 9 blasting SPP and MISO for recent blackouts and high-priced leadership while advocating trying out *SEEM*.

The Bottom Line

A Louisiana commissioner says the state's utilities would be better off in the Southeast Energy Exchange Market. The Southern Renewable Energy Association said SEEM's numbers show that there's no way.

"Under the guise of regional cooperation, SPP and MISO have steadily eroded the authority of state commissions, drained resources from ratepayers, and handed over control to unelected bureaucrats. Executive compensation has soared while customer service has declined. This centralized, unaccountable model is a bad deal for American families and businesses — especially in the South, where traditional energy values and pro-consumer policies matter," Skrmetta said.

Skrmetta said instead of Southern states "being tied to bloated RTOs," SEEM could offer a "market that reflects the conservative principles of low overhead, local accountability and respect for state sovereignty." Skrmetta argued that in addition to eliminating a costly RTO bureaucracy, regulators and ratepayers would enjoy more authority under SEEM, which prioritizes "performance, not politics."

Skrmetta asked Southern utilities to notify MISO and SPP of their intention to leave; he said regulators, governors and utility CEOs should coordinate on transition plans.

"Defenders of the current system claim SPP and MISO bring 'market benefits' and 'supply diversity.' But when it mattered most — during storms and heat waves — they failed. What good is diversity if it doesn't work?" Skrmetta wrote.

However, Mahan said SEEM audit reports show that offers decline during periods of high demand. The Independent Market Auditor's report from December 2022 described scarce offers and zero matched trades during record cold and blizzards Dec. 24-26, when members Tennessee Valley Authority and Duke were forced to order rolling blackouts.

"It is not really working in a way that you can depend on it during extreme weather events," Mahan said of SEEM.

Since before the market's launch in 2022, SEEM's critics — which include SREA, the Southern Environmental Law Center, the Carolinas Clean Energy Business Association, the Sierra Club and the Southern Alliance for Clean Energy —have argued it would entrench the power of monopoly utilities while providing limited benefits to customers compared to alternatives. (See *After One Year, SEEM Still Drawing Criticism*.)

Mahan said SEEM doesn't offer forecasting, a day-ahead market, locational marginal prices or transmission planning. He added that SEEM doesn't appear to involve state regulators in decisions or maintain stakeholder groups for transparency.

Bill Booth, a consultant to the Mississippi Public Service Commission, asked if Mahan's presentation was meant to dissuade regulators from considering SEEM membership over MISO.

Mahan said he was there to provide more information about how the SEEM market functions. He added that he preferred a locational marginal pricing setup over a voluntary buy and sell approach led by utilities because the former is much more transparent.

"It's not entirely clear how the utilities come up with the prices for the offer or sale of energy," Mahan said.

Mahan added that no utility appeared to be arguing that SEEM is lowering retail rates, with no docketed rate case demonstrating any savings.

Booth insisted that MISO South regulators are just "looking for the lowest cost" and said MISO's membership rates are expensive.

Mahan responded that "MISO and SPP provide more value to the ratepayers that can flow through their bills" than SEEM's lackluster savings for the Southeast.

SEEM did not respond to *RTO Insider*'s request for comment on Skrmetta or Mahan's positions. SEEM's most recent *press releases* contain an 800 media hotline that connected to a KOA campground in Greensboro, N.C.

Mahan noted the dockets over the years from MISO South states that investigated savings estimates and explored alternatives to remaining in MISO.

"Some of those dockets, I've noticed, have become more and more redacted," Mahan said. He requested regulators consider revealing some of the redacted language.

Brown said Entergy makes its savings reports public and redacts information only when it would be "harmful to customers' interests."

"That's why we protect it. It's not that we have secrets," Brown said.

Mahan also recommended the Mississippi PSC open a docket to investigate SEEM member Mississippi Power to get "real world data" on how the utility is engaging with the market and the savings it has experienced. ■

IMM: NERC Reliability Assessment Still Overstating MISO Risk

By Amanda Durish Cook

MISO's Independent Market Monitor has expressed lingering dissatisfaction with NERC's Long-Term Reliability Assessment, even with potentially corrected values.

MISO IMM David Patton said though NERC would rerun the numbers on its assessment regarding MISO's risk, it appears MISO will be downgraded only to an "elevated risk" from "high risk," which he said he still disagrees with.

NERC in June said it would rerun the numbers on expected risk for MISO after the IMM discovered an inconsistency in the assessment. NERC apparently used unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. (See *MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot*.)

Why This Matters

MISO IMM David Patton indicated he's still unhappy with NERC's Long-Term Reliability Assessment, even with the agency demoting MISO's risk level.

Patton said NERC is likely to call out MISO for elevated risks for a few more summers despite the RTO maintaining an approximate 17% installed capacity requirement that more than covers forced outages during peak summer demand hours.

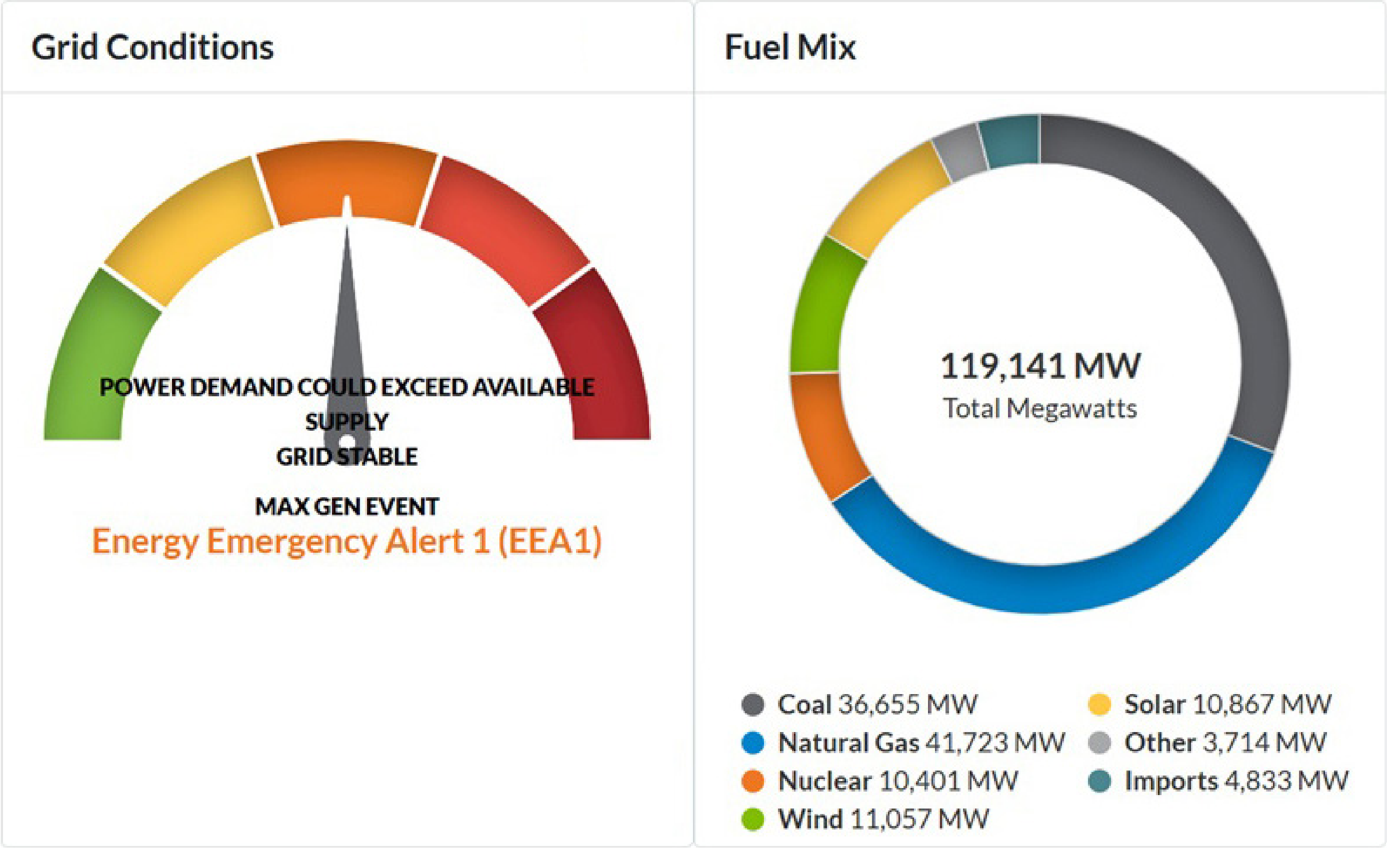
Patton said he believes reliability assessments chronically undercount MISO's interfaces, which grants it more access to imports from neighbors "than just about anybody."

"It has a powerful impact during emergencies," Patton said during a July 10 Market Subcommittee meeting.

He said even during MISO's late June emergency declaration in a wide-ranging heat wave, there was "virtually no potential for load loss." He said MISO's emergency declaration didn't escalate into load-modifying resource use and wound down after MISO was able to access the emergency ranges of generation. (See *MISO Declares Max Gen Emergency in Heat Wave*.)

"If you look at our neighbors, they were all having operating reserve shortages," unlike MISO, Patton said.

Despite his confidence in MISO, Patton urged the MISO community to keep an eye on "four to five years out" so the footprint continues to enjoy reliable operations. He said MISO nevertheless should "keep an eye on the pace of entry" for new generation and "continue to be flexible" to slow down retirements. ■



MISO's web dashboard at 5 p.m. ET June 23, during the maximum generation event | *MISO*

New MISO Stakeholder Code of Conduct Forbids Rude or Callous Language

Wouldn't Say Whether a Specific Incident Prompted the Rules

By Amanda Durish Cook

MISO debuted a code of conduct for its stakeholder meetings that forbids rude or callous language, deliberate meeting disruptions or disregarding committee chairs' instructions.

MISO *said* that by attending stakeholder meetings, all participants agree to maintain professional conduct, identify themselves and organizational affiliation before speaking, take turns speaking and make sure everyone has the chance to talk, stay on topic according to meeting agendas and minimize distractions caused by electronic devices.

The RTO added that it would not tolerate disruptive or disrespectful behavior, including name-calling or personal attacks; "dismissive, sarcastic or demeaning remarks," speaking out of turn and repeated interruptions, not following the meeting chair's direction and "conduct that impedes discussion or intimidates participants."

MISO said participants' failure to follow the rules and "repeated or egregious violations" could result in restricted participation or being refused entry into stakeholder activities. The code applies to participants attending meetings virtually or in-person.

In response to *RTO Insider*'s questions, MISO did not elaborate on whether a specific incident prompted the new rules, if the RTO noticed a pattern of troubling behavior in meetings or whether the rules were in the works for a while.

Why This Matters

While MISO always expected a little decorum at stakeholder meetings, its new code of conduct expressly disallows insults, interruptions, intimidation and sarcasm.

A MISO Resource Adequacy Subcommittee meeting underway | © *RTO Insider*

"MISO values stakeholder input and we want to ensure our stakeholder process reflects that," spokesperson Brandon Morris said in an emailed statement to *RTO Insider*.

MISO said reliable operations, competitive wholesale markets and collaborative transmission planning requires "engagement built on a foundation of mutual respect, professionalism and fair debate and dialogue to solve complex regional issues."

The code states that MISO's proposals and presentations and reports from staff delivered during meetings are "often works in progress meant to promote discussion, negotiation and consensus-building." It also said meeting participants are expected to describe the contents of meetings "accurately and contextually" — with the understanding that opinions evolve — when sharing meeting information in news reports, social media posts, blogs or the like.

In a July 9 letter to stakeholders introducing the code, MISO CEO John Bear said he valued stakeholders' diverse perspectives but said MISO stakeholder forums "also demand professionalism and mutual respect." He asked the stakeholder community to keep engagement "constructive" and treat fellow stakeholders with courtesy.

"Every comment should further respectful, solution-focused dialogue that fosters trust, encourages collaboration and upholds the high standards we hold at MISO, and you hold as representatives of your organizations," Bear wrote. "Disagreements are natural in these forums, especially when things are changing so quickly, but we all must remember that our engagement must be grounded in professionalism and respect, which, in turn, encourages fair debate and dialogue." ■

Grain Belt Funding Appears on Shaky Ground with DOE; Invenergy Firm on Value

By Amanda Durish Cook

Invenergy is standing by the value of its $11 billion, 800-mile Grain Belt Express transmission project with a letter to Energy Secretary Chris Wright, who is said to have pledged to block the line.

Grain Belt Express Vice President Jim Shield wrote July 11 that Wright should put aside "unfounded noise" and confirm closing of the Department of Energy's $4.9 billion in federal loan guarantees as Republican leadership in Missouri targets the line's federal funding.

U.S. Sen. Josh Hawley (R-Mo.) and Missouri Attorney General Andrew Bailey have taken aim at Grain Belt. Hawley sent a letter insisting that Grain Belt's conditionally approved DOE loan guarantee be pulled, while Bailey has opened a consumer protection investigation into the nature of the line's development. (See *Missouri AG Opens Inquiry into Grain Belt Express*.)

In a July 10 *press release*, Hawley said he secured a pledge from Wright to "halt" the line.

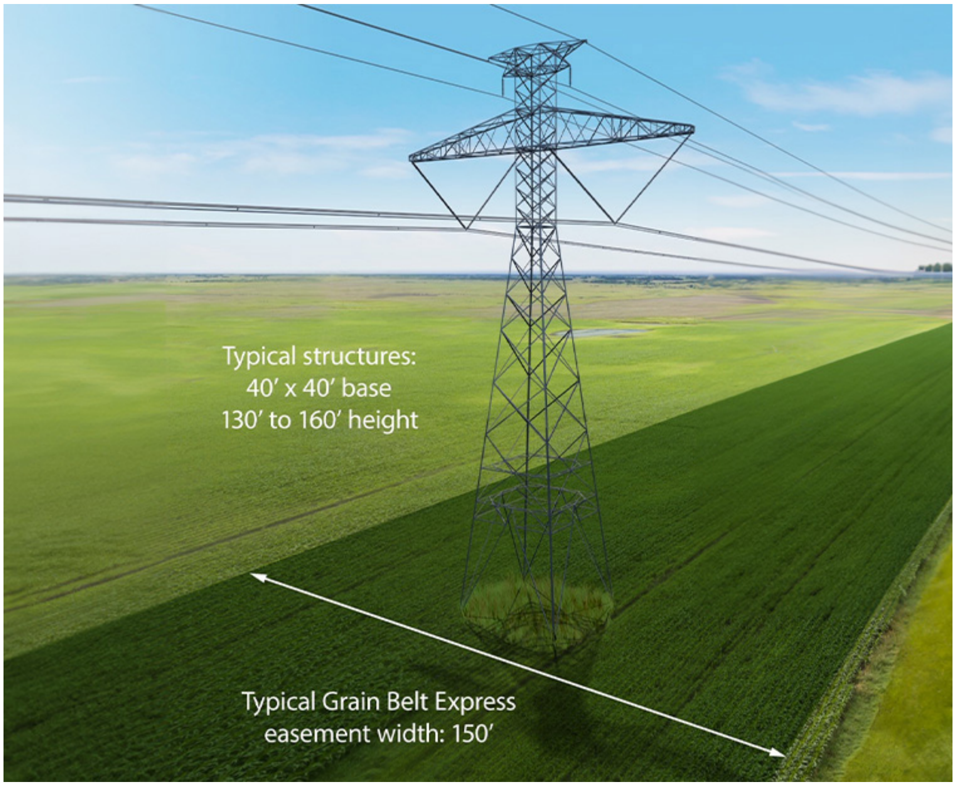
Hawley said in a follow-up social media post the same day that he had a "great conversation" with President Donald Trump and Wright, who he said pledged to "put a stop" to the project. Hawley called the Grain Belt Express an "elitist land grab harming Missouri farmers and ranchers" and claimed it is set to cost taxpayers billions of dollars.

Hawley has demanded for months that the Trump administration terminate government funding for Grain Belt and has questioned the line's viability.

"Your department should be taking every possible action to stop this loan — not only to save taxpayers' money, but also to save generational land from being ripped away from families and hard-working farmers and ranchers in Missouri," Hawley wrote in the June 25 letter to Wright.

'Open Season' on New Infrastructure

Shield said it's unfortunate Hawley and Bailey "are declaring open season on America's ability to build needed energy infrastructure" and that Grain Belt is the "target of egregious, politically motivated lawfare."



A Grain Belt Express tower visualization prepared for landowners | *Invenergy*

Why This Matters

The Grain Belt Express' $4.9 billion in conditionally approved federal loan guarantees from the DOE appear uncertain. Invenergy said the line's benefits are clear and is a 'test of America's will to build.'

He characterized Hawley and Bailey's "crusade" as "unwarranted and unhinged."

"Recent false accusations from Sen. Hawley and A.G. Bailey saying that the Grain Belt Express will cost America billions instead of saving us billions, whether mistaken or purposefully declared, are misleading at best," Shield said.

Shield wrote that Grain Belt is a "critical energy security project" that will deliver reliability and savings and is supported by a broad range of stakeholders.

"It is an open-access line that will deliver all forms of American energy based on customer demand and available market power, enhancing the ability of the largest grid operators to share power, including from generators directed to operate under DOE's 202(c) authority," Shield said, in an apparent attempt to appeal to the conservative leadership's pro-business philosophy.

Shield said the line — capable of delivering four nuclear power plants' worth of electricity and the second-longest line in U.S. history — would connect four of the country's grid regions while delivering cost savings and reliability to "29 states and D.C., more than 40% of Americans and 25% of Department of Defense installations."

Shield said recent questions raised by Bailey were addressed through the Missouri Public Service Commission's "long and rigorous" regulatory process that began in 2022 and concluded in late April. What's left is "procedural abuse" to roll back state regulatory approval that wastes public resources and harms the public, Shield wrote.

"The state of Missouri was represented throughout these proceedings, yet A.G. Bailey never intervened or otherwise contested the proceeding. Missouri law and constitutional due process protect the Grain Belt Express' property interest in its permit granted by the MPSC. No amount of political posturing and unrelenting attacks can change that fact," Shield said.

He said the timing of the "anti-growth" attacks doesn't make sense given the country's booming energy demand and that the line is even more important now than when it was conceived in 2010.

The CEO of Associated Industries of Missouri, a pro-business lobbyist organization, said Grain Belt is an "obvious solution," given demand growth from new manufacturing and emerging technologies.

"It is nonsensical to try to impede a project that will put Missourians to work constructing infrastructure that delivers affordable and reliable power of all kinds to Missouri businesses while enhancing grid security for America," CEO Ray McCarty said in a statement.

In a separate *press release* issued by Invenergy, the company questioned whether America has "lost its will to build."

"If projects can't count on certainty even after being approved and reviewed upon appeal, America can't count on ever getting steel in the ground. America will lose the test of its will to build," Invenergy said. The company lamented "political actors making last-gasp attempts to reopen existing state approvals or halt a yearslong federal review in its tracks."

Invenergy noted that states lead on transmission permitting and said Grain Belt already has cleared Kansas, Missouri, Illinois and Indiana's routing processes. It said it made "every effort" to negotiate with landowners.

"Grain Belt Express has among the strongest set of landowner protections and compensation packages, including a code of conduct and agricultural impact mitigation protocol. In fact, the Kansas Farm Bureau called for these protocols to be made a standard for the industry," Invenergy said. "Living up to our commitment that eminent domain be used only as an absolute last resort, land has been secured through voluntary agreements in all but a low single digit percentage of cases, a rate equal to or better than the utility industry standard."

Invenergy says it has completed over 95% of land acquisition for Phase 1, the segment connecting Missouri and Kansas. The phase's construction is scheduled to start in 2026.

Invenergy added that when it acquired Grain Belt from now-defunct Clean Line Energy in 2020, it invested in a redesign and listened to stakeholders' concerns, ultimately deciding to make more power deliveries to Missouri. (See *Invenergy Announces Grain Belt Express Expansion*.) ■

FERC Rejects Voltus' Appeal for Interim MISO Order 2222 Compliance

By Amanda Durish Cook

MISO is free to keep working toward its 2030 goal of fully incorporating aggregators of distributed energy resources into its markets without an interim participation option, FERC ruled in an order on rehearing.

The commission's July 10 order denied aggregator Voltus' request to compel MISO to reinstate a temporary role for aggregators in its markets while it works on full FERC Order 2222 compliance (*ER22-1640*).

MISO nixed the provisional step from its first compliance proposal in the spring after the commission said it didn't fit within the requirements of Order 2222. The RTO planned to use an existing demand response participation category to get aggregators of distributed energy resources participating on a limited basis a few years ahead of its full implementation. (See *MISO Discards Interim Participation Option from Order 2222 Plan*.)

FERC disagreed with Voltus' contention that it got it wrong when refusing the partial participation. The commission said its history of accepting interim models while grid operators work on full compliance with orders and directives on a longer timeline didn't apply in this case because MISO's *pro tem* demand response plan contained elements that didn't square with Order 2222.

FERC said its precedent of approving an interim plan for electric storage resources in MISO markets before the RTO complied with Order 841 was fundamentally different because that case dealt with a Section 206 complaint under the Federal Power Act, not Order 841 itself. Voltus cited Indianapolis Power and Light's (now AES Indiana) 2017 complaint over MISO's treatment of the utility's Harding Street Battery Energy Storage System when arguing for rehearing. (See *MISO Ordered to Change Storage Rules Following IPL Complaint*.)

FERC said it continues to find MISO's provisional demand response model lacking, namely its failure to meet Order 2222's 100-kW minimum size requirement for aggregations. The commission also said it was unpersuaded by Voltus' claim that it ignored the benefits of a timelier rollout of at least some Order 2222 directives. FERC said it wouldn't debate a piecemeal implementation further.

FERC backed MISO's 2030 effective date for its comprehensive distributed aggregation model and said it was "timely," irrespective of a partial rollout.

What's Next

Full acceptance of DER aggregations in MISO's wholesale markets is still on the horizon in 2030 after FERC refused a rehearing request from Voltus that argued for limited participation while MISO readies settlement computer systems.

The commission once again underscored MISO's reasoning that its underlying computer systems need work over the next four years before they can support aggregations.

"MISO stated that the foundational enhancements to its settlement systems are expected to be completed in the middle of 2028," FERC said. It disagreed with Voltus that MISO didn't expound on which specific settlement upgrades would be necessary, and said MISO provided detailed timelines that outlined delays and additional work. ■

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MISO Monitor Targets Tx Congestion in State of the Market Report

IMM Makes 4 New Recommendations

By Amanda Durish Cook

MISO's Independent Market Monitor has released four new market improvement recommendations for MISO concerning transmission congestion, the Midwest-South transmission link, market-to-market coordination and price settlements after grid devastation.

IMM David Patton said the recommendations, provided as part of his annual State of the Market Report, should better position MISO for load growth combined with a renewables-heavy future.

Freeing up Space on Midwest-South Constraint

Patton said he wants MISO to maximize its Midwest-to-South transmission limit by being less conservative with the space it reserves for unforeseen flows.

MISO actively derates its Midwest-South transfer constraint to keep flows in either direction below the contractual limit. Unmodeled flows over the constraint can push flows up and violate the limit.

But Patton said MISO's caution has caused the transfer's utilization to be just 84% of what's contractually allowed. He said MISO should work in extra, lower-value steps to the transmission limit's demand curve and raise its energy-plus-short-term reserve limit to the highest penalty step on the transfer to use the transmission more. He said a more detailed curve and relaxed limits could increase the path's utilization when the value of transfers is high.

| © RTO Insider

Patton also said the changes could reduce the burden on MISO operators to "constantly monitor and adjust the … limit in the real-time market."

Think Before You M2M

Patton advised MISO to stop accepting SPP's requests for constraints to be moved to market-to-market coordination unless it's "clearly warranted." He said MISO should accept monitoring responsibility of SPP's flowgates only if it can provide "significantly more" efficient relief on the constraint than SPP.

Patton said in some cases, MISO has accepted an M2M designation for flowgates from SPP even when it cannot deliver economic respite.

"They end up being a lot more costly in the MISO dispatch than in the SPP dispatch. And that costs MISO customers a lot of money," Patton said of market-to-market flowgates.

Though he didn't mention it in his presentation, Patton was among the first to alert stakeholders that MISO could offer little relief for a MISO-SPP flowgate in North Dakota strained by a new cryptocurrency mining facility. The situation in 2023 spurred complaints from the MISO side and a FERC refusal to refund about $40 million in congestion costs. (See *FERC Again Declines Changes, Refunds on Crypto-burdened MISO-SPP Flowgate*.)

More Frequent FTR Auctions

MISO should move to a primarily monthly or seasonal format for auction revenue rights (ARRs) and financial transmission rights (FTR) auctions, Patton said. He said MISO should shift the bulk of its transmission capability from the existing annual FTR auction to seasonal or monthly auctions.

Patton said more lines joining a more frequent FTR/ARR auction process would limit overselling of FTRs or over-allocating ARRs on constrained lines, especially when MISO isn't made aware of its transmission owners' outages.

He said MISO's transmission owners often report outages too late to be reflected in the annual FTR auction, with the network more accurately modeled in MISO's less attended monthly auctions.

But Patton said MISO's current monthly auctions deliver less net FTR revenues than the value of day-ahead congestion, indicating a lack of participation.

The Market Subcommittee launched a renewed effort to improve the FTR/ARR market at the same July 10 meeting where Patton presented his State of the Market report. MISO's Tony Hunziker said MISO would dig in at the August meeting, exploring ways to bolster FTR market performance and participation, improve model accuracy, ensure funding and better link the day-ahead market to the FTR market.

More Inclusive Impetus for 'Forced-off' Pricing

Finally, Patton said MISO could improve its criteria for pricing when an extreme event forces portions of the grid offline.

Patton said the recommendation applies to MISO's "forced-off asset" event declaration, which sets real-time prices equal to day-ahead prices. MISO created the new settlement practice in 2024 for generators physically disconnected from the grid during extensive transmission outages triggered by extreme events. It's designed to prevent generation from receiving excessive penalties or undeserved windfalls. (See *FERC OKs MISO Settlement Rules for Widespread Tx Outages*.)

Patton said even though 2024's Hurricane Beryl forced transmission offline that disconnected most loads in the South-

Continued on page 33

What's Next

MISO has until October to respond to the four new market recommendations its IMM made.

Stakeholders Question MISO Plan to Reassign LSEs' MW Duties Based on Risky Periods

By Amanda Durish Cook

MISO stakeholders are skeptical of the RTO's proposed new approach to divvying up reliability obligations among load serving entities (LSEs) based on evolving system risk.

The RTO revealed early in 2025 that it intended to rearrange the reserve margin obligations it parcels out among its LSEs to align with historical load during the most perilous hours on its system. (See *MISO Ponders Redistributing LSEs' MW Obligations Based on Demand During Risky Periods*.)

At a July 9 Resource Adequacy Subcommittee meeting, MISO said it would make a few changes from when it announced its plan about six months ago. Now, it plans to use different demand hours that determine the allocation and keep those hours in place for three years at a time in a bid for the allocation to be more stable for LSEs' resource planning.

MISO assigns its LSEs a portion of its overall planning reserve margin requirement (PRMR). Today, the grid operator divvies up the PRMR based on LSEs' 50/50 load forecast for MISO's coincident peak. MISO said because of shifting and growing risks to the system, its reliability requirement should be reallocated among LSEs based on periods that contain the highest reliability risks. MISO previously said there's a mismatch between LSEs' obligations and the load LSEs are consuming at the times of greatest need on the system.

MISO Market Design Economist Bill Peters said though MISO needs to change the responsibility of each of the LSEs because risk is shifting, it also needs to respect that LSEs "need stability and a way to plan" with a somewhat stable PRMR allocation year over year.

MISO is reassessing its PRMR allocation partly because it moved to an availability-based capacity accreditation based around risky hours, not peak load. Peters called reallocating the PRMR the "opposite side of the coin" to accreditation.

But MISO no longer proposes to use the same set of annual risky hours that it uses for its capacity accreditation, when resource availability is expected to be less than 25% of operating margin. Instead, it plans to devise what it calls "seasonal expected resource adequacy risk hours" that will be fixed for three years at a time. Peters said those hours still would ensure that LSEs furnish output during the times of greatest need.

Bill Peters, MISO | © *RTO Insider*

Why This Matters

MISO says basing LSEs' megawatt obligations on multiple risky hours that occur throughout the year — not an annual peak — and fixing them for three years at a time should give members the stability they need to plan generation. Stakeholders aren't so sure.

MISO staff stressed that the seasonal expected risky hours would be different than MISO's existing "resource adequacy hours," or the anticipated risk periods that MISO deems critical for its availability-based resource accreditation.

The seasonal expected risky hours would be derived from an analysis of the past three years of historical resource adequacy hours. Peters said the analysis would examine how the hours are "trending and when are we seeing risk."

Peters said MISO may consider updating the hours if "substantial changes" occur sooner than the three-year cycle. He said MISO would have to set criteria for what magnitude of change could trigger an update outside of the regular three-year cadence.

Peters said a MISO analysis of five years of data has shown that resource adequacy hours "slowly shift but remain relatively stable" year-over-year, making the three-year option viable.

Stakeholders asked if MISO expects the seasonal resource adequacy hours to change dramatically from one three-year set to the next.

"I expect some different hours in the next three-year iteration," Peters said, but didn't venture a guess as to what degree.

Peters said MISO no longer can portion

out the PRMR based on a single annual peak demand period, as is done now.

"We have a lot of capacity availability while the sun is shining now," Peters said. "The model is showing us we have problems when the sun goes down. That's different than what we're used to."

MISO has about 14.5 GW of solar capacity and counting.

"Should your obligation be based on a peak period where the sun is shining and system risk is low? We think not," Peters said.

Peters said the shared PRMR obligations are emblematic of the interconnected nature of the system and how "your actions affect everyone else." He said the PRMR allocation exemplifies the Hawaiian word "kākou," which expresses collective responsibility, or "we're all in this together."

Peters said MISO still needs to add historical meter data on demand reductions and behind the meter generation from LSEs to get the full picture of net settled load to provide allocation examples. He said without that information, MISO cannot allocate the PRMR properly.

Some stakeholders said MISO needed to collect that LSE-level data before proposing the new design.

Attorney Jim Dauphinais, representing multiple industrial end-use customers, said he had "serious concerns with the proposal" because it relied on too many hours —upwards of 500 in the summer based on MISO's illustrative example — and didn't appear to account for actions LSEs might take in emergencies or near emergency situations to cut back load.

"It seems like almost an overcompensation for the stability issue and dilutes the price signal of trying to keep load off of true loss of load risk hours," Dauphinais said. He said he feared the proposal would eliminate the incentive to reduce load and warned that load that hasn't shown up before on the system in certain hours could begin cropping up.

WPPI Energy's Steve Leovy said MISO didn't provide enough data to show that the PRMR allocation would give LSEs the steadiness they need to plan. He said he saw "nothing" in MISO's proposal that would prevent an LSE's obligation from jumping "four or five percentage points" from one year to the next.

"We're getting way too ahead of ourselves without knowing what the results of this process would look like," he said.

MISO's Davey Lopez said MISO's proposal is far from final. MISO said it hopes to file a new PRMR allocation for FERC approval sometime in early spring.

Dauphinais said MISO would be better off using an allocation based on demand during a few hours of net peak throughout the year rather than trying to tie the proposal loosely to RA hours.

Minnesota Power's Tom Butz said MISO should ask itself whether it's seeking to truly quantify risk or develop a "mechanism of math."

"The chances of this being stable are really, really low," Butz said.

MISO is collecting stakeholder opinions on its PRMR allocation blueprint; staff will return to the Resource Adequacy Subcommittee in August for more discussion.

At the April Resource Adequacy Subcommittee meeting, Public Utility Commission of Texas economist Werner Roth said the proposal might introduce "a ton" of complexity for little payoff. ■

MISO Monitor Targets Tx Congestion in State of the Market Report

Continued from page 31

east Texas Load Pocket, the storm failed to qualify as a forced-off asset event. He said MISO should tweak portions of the declaration, namely its constraint management and dead bus criteria, to trigger the settlement style.

Patton said MISO defines its revenue inadequacy criteria too narrowly to have activated the pricing and that to address the issue, MISO should add price volatility make-whole payment criteria to the revenue inadequacy criteria when making the call on forced-off asset declarations. He said MISO also should limit the forced-off asset dead bus criteria to load buses only.

Patton said the two adjustments should "ensure that prices in areas affected by transmission damage during extreme weather events are set at reasonable levels and avoid cost-shifting."

You Must Decommit

Before wrapping his report, Patton took time to call back to a 2023 recommendation that MISO develop tools to recommend decommitment of resources that have been committed in the day-ahead market.

Patton said in early July, MISO racked up $38 million of congestion because there were two gas turbines committed in the day-ahead market that MISO refused to switch off. He said the transmission constraint in question was in violation for six to seven hours. Patton said that sort of circumstance has a simple fix: turning off one or both of the gas turbines.

However, Patton said "MISO will do virtually anything other than" decommit a resource. Patton said there didn't appear to be a good reason behind MISO steadfastly refusing to decommit resources. Beyond that, Patton praised MISO's market performance over 2024.

"In many respects, MISO's markets are more advanced and well-developed than other RTOs, leading to superior performance," Patton said.

Patton said MISO's all-in energy price was an average $31/MWh in 2024, lower than the previous year due to an 8% decrease in natural gas prices. He said there was "little change" in average load from 2023.

MISO will review the Monitor's report through September and post a public response to the recommendations in October. MISO's response will include to what extent it agrees with the recommendations and how doable it believes each one is. ■

MISO Ready to Discontinue Seams Stakeholder Group

By Amanda Durish Cook

MISO appears poised to eliminate its Seams Management Working Group (SMWG) after about 15 years.

The Market Subcommittee voted via a simple majority at a July 10 meeting to sunset the group. MISO's Steering Committee is set to vote at its Aug. 5 meeting to confirm or deny the cancellation.

Group chair Terry Jarrett, of the Missouri Joint Municipal Electric Utility Commission, said topics have dried up since 2023, with "minimal content due to most major seams topics being covered in other forums" and fewer seams data points provided by MISO to the group. Jarrett also noted that transmission planning at the seams has become a more attention-grabbing topic than seams management.

Jarrett said the "participation rate has dwindled over the years" to a dozen or two dozen attendees when other stakeholder committees attract a hundred or more.

Jarrett said from his tracking since 2022, there have been 13 SMWG meetings scheduled, with just two containing substantive discussions. Eight covered only "minimal content and participation" while three either were canceled or downgraded from meetups into documents that MISO posted to its website for review, he said.

Jarrett added that the group has been lacking a vice chair since late 2022 due to low interest among the stakeholder community.

MISO's headquarters in Carmel, Ind. | © *RTO Insider*

"There's really nothing going on for the SMWG to do, and nothing on the horizon," Jarrett said.

Jarrett said discussions on MISO's seams issues should be transferred to Market Subcommittee meetings.

"Working groups are intended to be temporary. It is clear that the SMWG has successfully rallied MISO and the stakeholder community around seams coordination. With seams coordination effectively operationalized at MISO, there isn't much value left for a dedicated seams working group," Jarrett said.

Jarrett said at the group's May meeting, he put a possible sunset of the group to a vote. Jarrett said despite a record 46 participants listening in, only eight individuals voted, resulting in a 4-4 stalemate.

MISO Independent Market Monitor Carrie Milton requested that MISO continue to focus on seams topics, including MISO and PJM's ongoing effort to revise their 2004 freeze date used to determine flow rights and the issue of sharing capacity near the regional transfer limit between MISO Midwest and MISO South, SPP and other parties. ■

MISO to Axe Energy Efficiency from Capacity Market Participation

By Amanda Durish Cook

Why This Matters

After years of its IMM questioning the value of energy efficiency as a capacity resource, MISO is ready to seek FERC permission to bar it from its capacity auctions.

MISO said it no longer will recognize energy efficiency as a capacity resource beginning with the 2026/27 auction. If approved, the action would satisfy a longtime recommendation from MISO's Independent Market Monitor.

The grid operator said it needs to address market participants' double counting of energy efficiency measures before the next capacity auction in April 2026. It plans to make a filing to FERC in early September to enact the ban by December.

Research and Development Manager Geoff Brigham said while MISO will deny energy efficiency entry into the capacity auction, it will continue to allow energy efficiency to be reduced from load-serving entities' coincident peak load forecasts. Brigham said energy efficiency resources often are part of utilities' integrated resource planning and are recognized by states.

After FERC proposed a landmark, nearly $1 billion penalty for American Efficient's apparently bogus programs in PJM and MISO, MISO conducted an audit of all energy efficiency resources offered in the 2025/26 Planning Resource Auction. Brigham said staff found that a "significant portion" of the resources were offered into the auction while already being accounted for in LSEs' coincident peak load forecast.

MISO's tariff stipulates that energy efficiency resources cannot qualify to be auctioned off when they're already reflected in the RTO's peak load forecast.

MISO said it confirmed with local distribution companies that "all savings derived from state-mandated energy efficiency programs are included in their coincident peak forecasts."

Brigham said MISO also found some resources submitted incomplete information that fell short of MISO's measurement and verification standards.

"MISO is in the process of adjusting each resource's accreditation and capacity payments," he said.

MISO IMM David Patton has long said MISO should consider discontinuing energy efficiency capacity payments. He has said the benefits of energy efficiency exist for customers with or without the benefit of the MISO markets.

At the annual OMS Resource Adequacy Summit in Chicago, Patton said energy efficiency in the capacity markets "has been a bit of a debacle."

"I think it's time we follow through," Patton said again at the March 2025 Board Week in New Orleans, where he referenced PJM's move to eliminate energy efficiency from its capacity market. He said energy efficiency isn't a "legitimate" capacity product.

"We really believe that energy efficiency serves no purpose in MISO markets," fellow Monitor Carrie Milton said at a Jan. 16 Market Subcommittee meeting. ■

MISO control room | *MISO*

NYISO Details Late June Heat Wave for Reliability Council

By Vincent Gabrielle

ALBANY, N.Y. — NYISO performed an *autopsy* on the system conditions during the late June heat wave for the New York State Reliability Council at its Installed Capacity Subcommittee meeting on July 10.

"We got a net demand on the 24th of 31,857 MW, which is over our 50/50 forecast by a couple hundred megawatts," said Aaron Markham, vice president of operations for NYISO. "When we add back in the assumed behind-the-meter [solar], we were pretty close to the 34,000 MW load we hit in 2013." (See *NYISO Issues Energy Warning as Heat Wave Boils N.Y.*)

By 3 p.m., Markham said, neighboring reliability coordinators reduced imports to New York by about 730 MW, increasing to 1 GW by 5 p.m. NYISO cut exports in response, to a total of 1,660 MW by 5 p.m.

Between 5 and 6 p.m., the Astoria 3 generator tripped and NYISO declared an Energy Alert. The ISO escalated the alert to an Energy Emergency at 7:13 p.m. as more imports were cut. As the evening wore on, NYISO purchased emergency energy to meet 30-minute operating requirements several times.

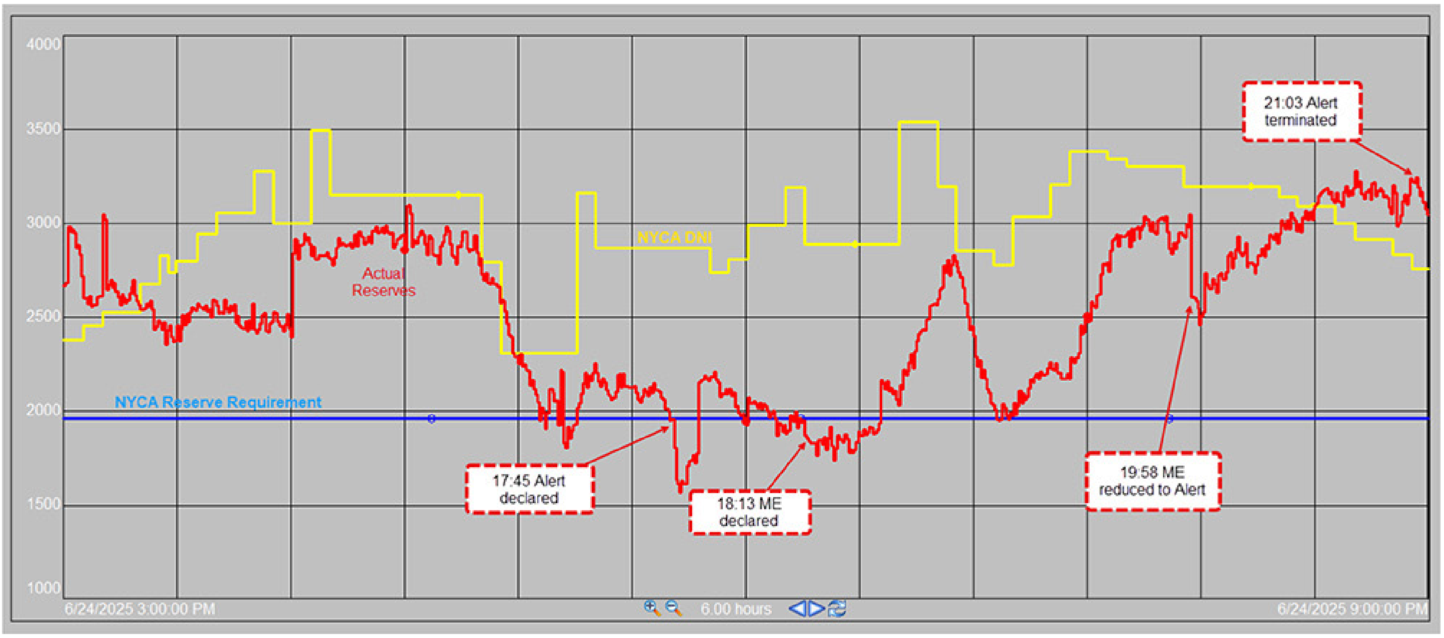
| *Shutterstock*

In total, about 2,000 MW of power were curtailed from NYISO from neighboring areas. New York generators tripped or otherwise experienced performance issues, resulting in about 1,000 MW of derates during peak hours.

"The driver was really high demand that stressed system conditions regionwide due to the heat and performance issues," Markham said.

NYISO called on all the demand response programs and saw about 1,000 MW of relief. It also dispatched generation to optimize 30-minute reserves. The ISO purchased about 1,960 MW across all available interfaces.

Markham said all fuel types were needed during the event but that it looked like wind and solar did better than NYISO initially assumed they would in its summer capacity assessment. ■



Timeline of the energy use of the New York Control Area. | *NYISO*

Earthjustice Blasts NYISO 'Power Trends' Report to State Officials

By Vincent Gabrielle

ALBANY, N.Y. — Earthjustice claimed that NYISO's latest annual "Power Trends" report was full of misleading statements that favor new natural gas generation in a *letter* July 7 to New York state officials, including Gov. Kathy Hochul.

"The 'Power Trends' report is not based on new information or analysis but is rather a summary of prior NYISO reports and analysis, none of which found that fossil-fired generation is necessary for reliability or that repowering aging power plants is beneficial for New York or the grid," Earthjustice wrote. "Instead, it seems that NYISO is irresponsibly seeking to create a false narrative that New York needs new gas generation, even though there is no evidence to support that claim."

The organization noted that NYISO had not made any new finding of a reliability need and called into question its concerns about large load additions, arguing that "many recent reports have noted the uncertainty of those speculative new loads."

"NYISO is using reliability as a way to justify more gas infrastructure, even though their own analysis shows no new reliability need exists," wrote Eric Walker, energy justice senior policy manager for WE ACT for Environmental Justice, who co-signed the letter. "Meanwhile, clean energy projects that could save New Yorkers billions are stuck in NYISO's interconnection queue. Delaying renewables and expanding gas infrastructure isn't just bad policy; NYISO's false narrative puts environmental justice communities further in harm's way."

The report, released June 2, included a section outlining the case for the refurbishment and repowering of old power plants, though it did not favor any particular resource. (See *NYISO Makes Case for Repowering in Latest 'Power Trends' Report*.)

"We encourage every policymaker to read 'Power Trends' for a fact-based assessment of electric system reliability, climate policy advancement and economic development," Kevin Lanahan, NYISO vice president of external affairs and corporate communications, said in a statement. "'Power Trends' suggests that repowering of all aging resource types — renewable and fossil — be examined to determine the opportunity for capacity additions, efficiency and carbon reductions."

Rachel Spector, deputy managing attorney for Earthjustice, said the organization had noticed signs of backsliding on New York's climate law from local officials.

"We are starting to hear from agency folks the idea that we need to start thinking about repowering gas plants or adding new gas generation," Spector said. "It seems like it was clearly in response to 'Power Trends.'"

Spector said Earthjustice has "real concerns" about New York's commitment to meeting its clean energy goals and the requirements of the climate law.

"We don't want to deny that there are major issues we have to figure out in the coming years with the grid, but there are a lot of things we could be doing, like speeding up renewables," Spector said.

The letter, also signed by representatives of the Environmental Defense Fund and Evergreen Action, notes that the report says the interconnection queue contains nearly 350 proposals, with nearly 50,000 MW of proposed clean resources.

Lanahan cited the Alliance for Clean Energy New York's support of NYISO's recent interconnection changes for reducing the wait time in its queue.

ACE NY Executive Director Marguerite Wells told *RTO Insider* that the report showed the state is not deploying resources fast enough, and the organization hopes NYISO's "significant reforms" will save time as the process matures.

"But it is not enough to reform one process, especially in the wake of federal hostility," Wells said. "To fully realize the immense benefits that renewable energy projects can bring, we need all state agencies to work together. NYISO has shown that new generating sources are needed in the coming years. Wind and solar power are the resources that can be online in the shortest time."

Wells said "red tape" should not force the state to rely on "technologies of the past" when renewables are ready to go.

Hochul's office did not respond to a request for comment by press time. ■

Astoria Generating Station in Queens | *Ben Schumin, CC BY-SA-2.0, via Wikimedia*

N.J. Mulls PJM Withdrawal amid Energy Shortfall Predictions

Legislature, BPU Evaluate Leaving the RTO, Other Options

By Hugh R. Morley

Anger over a recent dramatic electricity-rate hike and fears of energy shortfalls due to a predicted future rise in demand have prompted New Jersey to look anew at whether the state should consider pulling out of PJM or otherwise re-organize the relationship with the RTO.

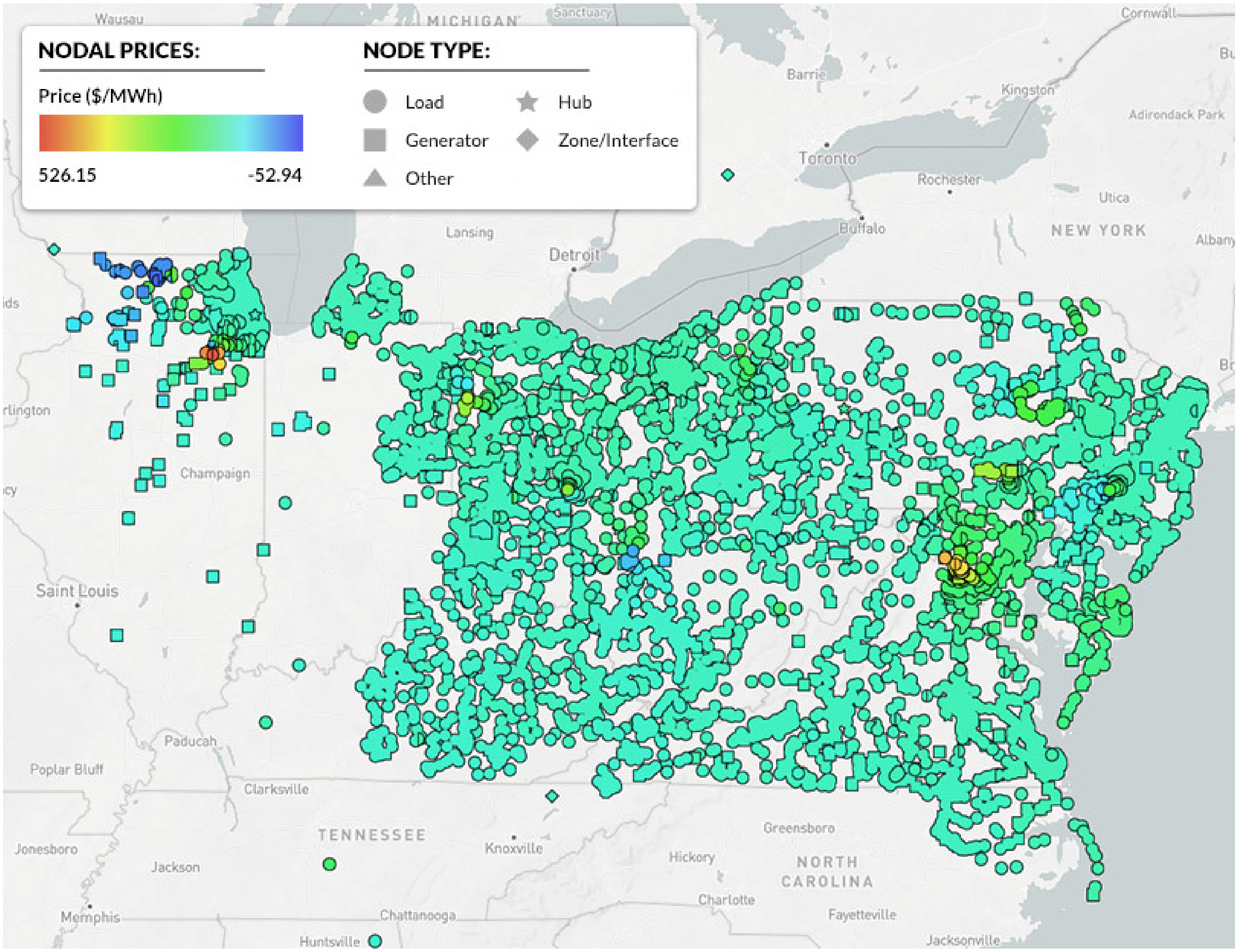
A bill introduced by three Assembly Democrats, *A5902*, would require the New Jersey Board of Public Utilities (BPU) to "work in collaboration with other states to explore alternative options to PJM's capacity auction for securing the capacity necessary for grid reliability."

Specifically, the states would study whether they should withdraw from PJM's reliability pricing model and develop a multistate compact to engage in the fixed resource requirement alternative to secure electric capacity through contracts with private entities, competitive capacity auctions or some combination.

The group also would look at whether they should "withdraw from the regional, high-voltage electric transmission grid operated or managed by PJM Intercon-

The Bottom Line

One difficulty with New Jersey departing PJM would be the sheer logistics of setting up a new system, coupled with coordination issues associated with adding other states to the mix that would be needed to make the venture viable.



Average evening prices in PJM from June 22 to 27. | *Yes Energy* nection." And the group would look at the merits of creating an independent electric transmission grid or joining "an existing electric transmission grid that operates within another state or region."

In an unrelated move, the BPU has organized a technical conference Aug. 5 to focus on "concerns over resource adequacy." Among the conference goals is to "evaluate alternatives to the PJM capacity market" and to "identify potential paths forward in achieving long-term resource adequacy within the state of New Jersey."

Protecting Ratepayers

The two initiatives spotlight a concern New Jersey has voiced or studied several times in the past decade: that it does not get the energy quantity or quality — mainly enough clean energy — it wants from its partnership with PJM. Past efforts have not resulted in significant changes, but this time the severity of the situation — dramatic electricity rate hikes and a potential future power shortage — could have an impact.

Assemblyman Robert Karabinchak (D), a bill co-sponsor, said in a release announcing the bill's introduction that it will "start the tough but necessary conversation about PJM's future."

The RTO has "for far too long" operated in a way that "ignores the needs of the states in our region and saddles our residents with higher utility bills," he said. "Their inability to adapt has become harmful to families and businesses across the Northeast, and it's time we push for a system that works for us."

Assemblywoman Lisa Swain (D), in the same release, said it is "time we explore our options to find an energy partner that is better aligned to serve our communities."

"We have heard from our constituents, and we are committed to finding the most effective solution, whether or not PJM is a part of it," she said.

But PJM dismissed the suggestion that New Jersey would be better off if it departed from PJM.

"New Jersey needs new electricity supply; a 'leave PJM' bill is not going to solve that problem," said Jeffrey P. Shields, a spokesman for PJM. "Actually, it will make the investment climate for new supply in New Jersey far worse by creating uncertainty for private developers seeking to earn a return on their investments in New Jersey through PJM's markets."

He rejected the suggestion that PJM is at fault for the rate hike, calling it a "red herring." PJM has reformed its interconnection process and has approved 46,000 MW worth of power projects that are not getting built "due to industry challenges that have nothing to do with PJM," Shields said. "Of these, about 1,500 MW are in New Jersey, and another 1,800 MW are in the transition queue," he said.

"Even if you get both of these categories to build out in full, New Jersey is still very short of creating a balanced supply portfolio," Shields said.

Past Studies

The legislation follows a *similar study* launched in March 2020 by the BPU after FERC expanded its minimum offer price rule (MOPR) to include "all resources receiving state support," which effectively made clean energy resources more expensive in the auction, according to *the order* setting up the study. New Jersey considered the move a "direct attack" on the state's clean energy programs and feared it might disrupt state efforts "to shape its electric generation" and hinder clean energy development in favor of fossil fuel generation. (See *FERC Extends PJM MOPR to State Subsidies*.)

The BPU study was conceived to look at whether New Jersey could achieve its clean energy objectives "under the current resource adequacy paradigm" at PJM. If not, the order said, the study should "recommend how best to meet New Jersey's resource adequacy needs."

The BPU *updated that report* in 2022. But friction with PJM had erupted before: Then-BPU President Joseph Fiordaliso in 2018 *threatened to pull the state* out of PJM over frustration at a lack of coordination between the RTO and member states.

The recent proposals were triggered by the events that led to the 20% increase in the average electricity bill on June 1, levels that were set by the state's basic generation services (BGS) auction in February. State officials say the hike was shaped by PJM's capacity auction in July 2024, in which prices were 10 times higher than in the previous auction.

PJM says the sudden hike stemmed in large part from an unforeseeable rise in demand — mainly due to heavy energy-using data centers — and a looming energy shortfall, as the rapid closure of old fossil-fuel generators outpaces the much slower introduction of new clean energy facilities.

New Jersey officials, however, say the PJM capacity auction was flawed, with prices driven up by an inaccurate count of the impact of new clean energy sources. New Jersey Gov. Phil Murphy (D) has asked FERC to investigate "potential market manipulations" in the PJM base residual auction (BRA). (See *N.J. Gov. Urges FERC to Investigate PJM; Christie and Phillips Defend PJM*.)

BPU President Christine Guhl-Sadovy, in a written statement to FERC on May 28, as the agency prepared to hold a June hearing on the issues, said states like New Jersey "must be allowed to play a significantly greater role in ensuring resource adequacy at the lowest cost to ratepayers than is currently allowed by PJM."

"This includes being free to procure some or all of states' capacity needs outside of PJM's reliability pricing model (RPM), commonly referred to as the PJM capacity market," she said. Guhl-Sadovy also called for "significant reforms to PJM governance" to give states a greater role in resource adequacy planning.

Starting Anew

Yet the *previous study*, completed by BPU staff and the Brattle Group, showed that changing the status quo would be far from simple. An unrelated study also concluded it could be expensive.

"Incorporating New Jersey's clean energy goals in the regional market is the most efficient way to provide New Jersey consumers with reliable, affordable and carbon-free electricity," the Brattle report concluded, saying it would be "premature to consider leaving the regional market structure."

Project researchers studied several "resource adequacy alternatives that involved leaving the regional market and adopting a New Jersey-centric resource adequacy model under the fixed resource requirement (FRR) alternative," the report said. Under such a plan, New Jersey — and perhaps other states — would set up their own capacity auction, for developers to commit to developing future capacity, while remaining inside PJM for the energy market.

But the report concluded the state should wait while "important market reforms are being considered at the regional and federal level that could facilitate the rapid decarbonization of the electricity sector." The report found that customer costs under MOPR were the highest, but if it were removed, customer costs under the existing system would be cheaper than other options studied.

However, the report also said that "New Jersey should continue to explore the option to implement a New Jersey or multistate ICCM (integrated clean capacity market) under the FRR structure."

The 2022 update report, largely echoing the previous report, said New Jersey could meet its "clean energy targets at substantially lower costs by participating in a regional clean energy "buying pool," such as an ICCM, to purchase clean energy attributes."

Development Costs

The BPU eventually did not pursue any of the discussed changes, in part because PJM largely dropped the MOPR, removing the state's main concern. In addition, the election of President Joe Biden created a more friendly environment to renewable energy.

Observers of the situation said one difficulty with New Jersey departing PJM would be the sheer logistics of setting up a new system, coupled with coordination issues associated with adding other states to the mix that would be needed to make the venture viable. Another challenge would be attracting energy suppliers in an environment in which energy supply is expected to be scarce, putting New Jersey's venture in competition with PJM's own auction.

Furthermore, the cost of setting up the system could be hefty. A *report by the Independent Market Monitor* for PJM, titled Potential Impacts of the Creation of New Jersey FRRs and released in May 2020, concluded that net load charges for an FRR that covered all of New Jersey would cost between $32 million and $386.4 million, depending on the way it was calculated.

The monitor also questioned the efficiency of such a system.

"Creation of an FRR creates market power for the small number of local generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities," the report concluded, emphasizing that it is a "non-market approach" that excludes competition. "In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners, there are no market rules governing offers, and there are no market rules requiring competitive behavior."

Given the challenges, the suggestion that the state could leave PJM may be more of a negotiating strategy.

Alex Ambrose, a researcher for New Jersey Policy Perspective, a liberal-leaning think tank, said the main impact of the bill may be to refocus PJM.

"What would happen with this bill is that then BPU would study it," she said. "PJM will feel that pressure and New Jersey gains some leverage, and PJM implements the reforms that we want," such as improved governance and greater transparency in the RTO's decision making, she said.

Another possibility is that the BPU concludes that the state is better off leaving PJM, she said.

"What will end up coming out of this bill is better governance, more supply and better market rules for New Jersey," she said. ■

PJM Stakeholders Discuss Quadrennial Review Proposals

By Devin Leith-Yessian

PJM and several stakeholders presented proposals to define the contours of RTO's capacity market design for the 2028/29 Base Residual Auction (BRA) and the three following auctions as part of the market's Quadrennial Review.

The review aims to update the variable resource requirement (VRR) curve — which defines the amount of capacity the market procures and at what cost — to address changing market conditions. In a *report* commissioned by PJM, the Brattle Group said the key challenges that must be addressed are tightening supply and demand, uncertainty in the cost to build new capacity and accounting for several changes PJM has made to how it identifies reliability risks and determines the capacity value for different resource types.

The review also looks at the inputs to the VRR curve such as the reference resource technology class, whose costs are key inputs across the market; the cost of new entry (CONE) to build the reference resource in various regions of PJM; and the energy and ancillary services (EAS) offset, which estimates revenues outside the capacity market to net against CONE.

The Market Implementation Committee is set to vote on the proposals during its Aug. 6 meeting, followed by same-day Markets and Reliability Committee and Members Committee votes Aug. 20. The proposals also would require the approval of PJM's Board of Managers. PJM aims to file its recommendation with FERC by Sept. 30.

Stakeholders Divided on Reference Technology

Much of the discussion during the July 9 first read on the proposals at the MIC centered on whether to retain the combustion turbine reference resource or adopt PJM's recommendation to shift to a combined cycle unit in all regions except ComEd, where a four-hour battery electric storage system (BESS) would be the reference resource.

PJM's Skyler Marzewski said staff believe a CC is best situated for meeting demand. Developers have shown interest in building new resources based on submissions to the reliability resource initiative (RRI), a fast-track interconnection queue the RTO opened earlier this year. Six of the projects selected for expedited interconnection studies through the RRI were new CC resources. (See *PJM Selects 51 Projects for Expedited Interconnection Studies*.)

"There was no clear winner, but when we really had to sit down and pick one, it seemed like a combined cycle was the best resource … what that means is it was the most economical," Marzewski said.

PJM's *proposal* includes several changes to other Quadrennial Review components to account for the higher EAS revenues for a CC over a CT to prevent the midpoint of the VRR curve from "collapsing" — an issue that led PJM to reverse a shift to a CC reference resource in 2022. Marzewski said the viability of new CC units is helped by emissions standards proposed under EPA's power plant rule 111(d) being held in abeyance by the D.C. Circuit Court of Appeals, with a new rule likely being issued by the end of the year. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts* and *EPA Proposes Repealing Limits on Power Plant Greenhouse Gas Emissions*.)

The net EAS parameters would remain the same aside from updating unit-specific parameters to account for the CC and BESS reference resources, Marzewski said.

Requirements for gas generation to implement carbon capture technology under the Illinois Climate and Equitable Jobs Act led to storage being the most economic capacity resource, Marzewski said.

Independent Market Monitor Joe Bowring said the goal of the capacity market is to solve the "missing money" problem by ensuring capacity resources can recoup any costs to provide capacity above what they earn through the energy and ancillary service markets. While a CC has been the most common resource over the past few decades, the economics of their development are based on EAS revenues. Combustion turbines, however, would go bankrupt almost immediately without capacity revenues, making the capacity market critical to ensuring the viability of peaking units and defining the missing money.

The Monitor's *proposal* would use a dual-fuel CT as the reference resource, with some changes over the status quo for characteristics such as heat rate and operating and maintenance costs.

LS Power *proposed* to use a four-hour battery for ComEd and a dual-fuel CT for all other regions, with updated CONE values. Director of Project Development Tom Hoatson said the goal of the Quadrennial Review should be to stabilize the capacity market while stakeholders address more holistic issues in other stakeholder processes.

Hoatson said CCs are not dependent on capacity revenues to be viable in PJM, whereas CTs and battery storage cannot subsist on energy revenues alone.

Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow proposed a four-hour battery in ComEd and for all other regions a CC reference resource based on unit characteristics included in earlier IMM proposals, which would result in lower CONE values than the PJM proposal.

Changes to VRR Curve Shape

The PJM proposal also would revise the calculations defining the three points on the VRR curve: the maximum price would

Why This Matters

The Market Implementation Committee is set to vote on the proposals Aug. 6, followed by Markets and Reliability Committee and Members Committee votes Aug. 20. The proposals also require the approval of PJM's Board of Managers. PJM aims to file with FERC by Sept. 30.

be set to the greater of 1.75 times net CONE or 0.6 times gross CONE, while the midpoint would be half of the price cap. The status quo shape has a maximum price that is the greater of 1.75 times net CONE or gross CONE and a midpoint at 0.75 times net CONE. The minimum price would remain zero.

Marzewski said tying the midpoint to the maximum price instead of net CONE would prevent it from falling to zero when EAS revenues for the reference resource are high.

He said the proposed curve's performance is similar to the existing shape, resulting in a loss of load expectation of 0.084 events per year if net CONE is estimated accurately compared to 0.073 if the current shape is applied to a CC. With an accurate net CONE, Brattle's modeling estimated an average clearing price of $380 MW/day with a standard deviation of $155 and the price hitting the cap 9.5% of the time. An underestimated net CONE would have a clearing price of $532 MW/day and hit the cap 37.7% of the time, while an overestimate would clear at $228 MW/day and have a 0.5% chance of hitting the cap.

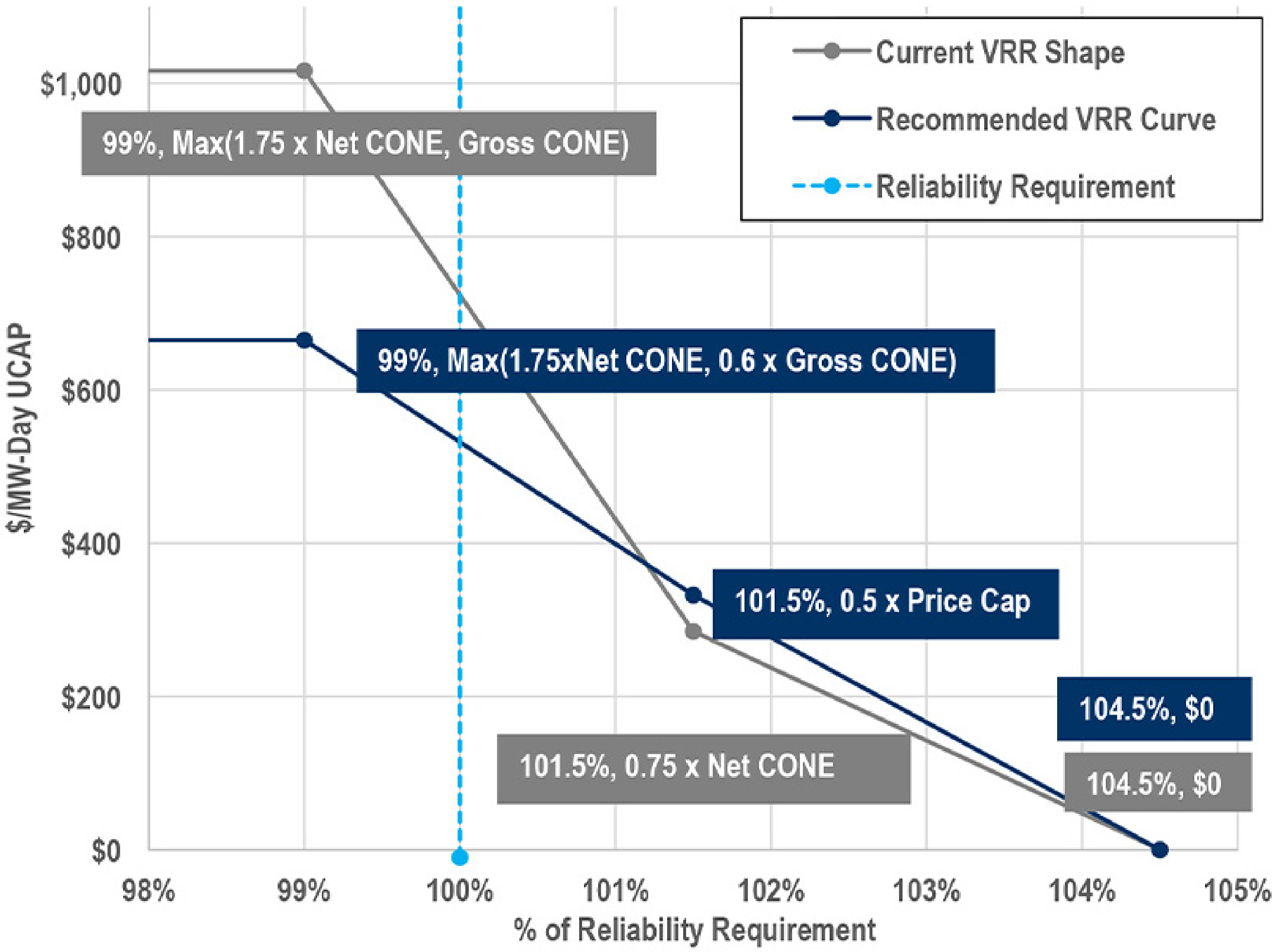
Marzewski said PJM opted not to follow Brattle's recommendation of a marginal reliability impact curve as most of the expected benefits also could be achieved by implementing a sub-annual capacity market design. During the June 18 Markets and Reliability Committee meeting, Pennsylvania Gov. Josh Shapiro's office introduced a problem statement and issue charge to shift to a seasonal market. (See *Pennsylvania Brings Seasonal Capacity Issue Charge to PJM*.)

The Monitor's proposal would set the maximum price at the lower of 1.5 times net CONE and gross CONE, consistent with the original PJM design, and set the midpoint at half of the maximum. Bowring said the gross CONE of a CC is significantly higher than the gross CONE of a CT and that PJM's proposed 1.75 times net CONE generally was greater than gross CONE in the most recent auction.

Bowring said current conditions in the capacity market are almost entirely the result of adding large data center loads. The result is likely to be future auctions clearing at the maximum price. He argued that the potential resultant triggering of the PJM backstop auction would mean the return of cost-of-service regulation for new generation. That would be inconsistent with the competitive market design and unfair to existing generators, he said. The Monitor has recommended repeatedly that the best solution in the capacity market would be to require new data center loads to bring their own generation.

Barrow's proposal would set the maximum price at 1.15 times gross CONE minus 0.75 times the EAS offset, with the midpoint at half that value. Unlike all other proposals and the status quo, the minimum price would be reached at 106% of the reliability requirement rather than 104.5%.

The LS Power proposal uses the status quo VRR curve shape. ■



A PJM graphic shows its recommended variable resource requirement (VRR) curve against the status quo shape in grey. | *PJM*

PUCO: Data Centers Must Guarantee Power Purchases from AEP Ohio

Groundbreaking Decision Shields Other Ratepayers from Project Failure Impacts

By John Cropley

The Public Utilities Commission of Ohio has granted AEP Ohio's request for tariffs requiring data center developers to financially guarantee they will use the electricity they are requesting.

Customers requesting more than 25 MW of new power for data centers will have to pay for at least 85% of the energy for which they are subscribed — whether they use it or not — for eight years. A ramp-up period of up to four years will be allowed before the eight-year term.

The *July 9 PUCO ruling* in *24-0508-EL-ATA* is among the first attempts in the U.S. to address the high costs associated with the huge new power demands that may result from data center buildout.

It seeks to ensure that other ratepayers are not stuck with paying for infrastructure upgrades made to accommodate demand that does not materialize as requested.

Along with the financial guarantee mechanism, the new tariff will create a sliding scale for small and mid-sized facilities to allow for some flexibility; require data center owners to prove they are financially sound and able to meet the requirements; and impose an exit fee for projects that are canceled or fail to meet the terms of their contract.

The state is seeing heavy interest in data center development, thanks in part to *favorable policies*. The Columbus area in the center of the state already has a strong concentration of these facilities.

Why This Matters

Costly transmission and generation expansion is being discussed nationwide for data center demand that not everyone agrees will be as huge as forecast.

In March 2023, AEP placed a moratorium on data center service requests in central Ohio so it could analyze the impacts of this trend.

In May 2024, it requested the data center-specific tariff, saying it was facing 30 GW of potential new load, some of it from sectors it considered to have elevated risk of not meeting their commitments. (See *AEP Ohio Asks PUCO for Data Center-specific Tariffs*.)

Representatives of data centers and other industrial sectors criticized the tariff request as an unprecedented and potentially chilling move. On Oct. 10, 2024, they submitted a settlement proposal.

AEP said some details in that proposal were problematic while other important details were omitted. On Oct. 23, the utility submitted its own settlement agreement, which revised or deleted some aspects of its original request. (See *AEP Ohio Proposes Revised Data Center Tariff*.)

Signing on to the submission were PUCO staff, the state *consumer utility advocate*, an organization for *large industrial ratepayers* and a coalition of 54 *community energy advocacy agencies*.

PUCO's unanimous ruling adopts AEP's settlement proposal, with some modifications to exit fees and other details. It directs AEP to file updated tariffs and lift the moratorium as soon as possible.

"Today's order represents a well-balanced package that safeguards non-data center customers on an industrial and residential level while establishing a dependable and reasonable environment for data centers to continue to thrive within Ohio," PUCO Chair Jenifer French *said in a news release*.

The industry membership group *Data Center Coalition*, which was an intervening party in the case, continues to maintain that no one industry or class of customer should be singled out for disparate rate treatment by a utility.

"The decision is a stark departure from solutions enacted in other key data center markets and, more consequentially, is a deviation from the long-established, sound ratemaking principles that have carried both Ohio and the nation through periods of electricity demand growth and flat demand," DCC Director of Energy Policy Lucas Fykes said in a statement.

AEP headquarters in Columbus, Ohio | *Shutterstock*

"The data center industry is committed to paying its full cost of service. DCC will continue to advocate for evidence-based solutions in Ohio and across the country that support data center development and advance an affordable and reliable electricity grid for all customers."

In a *news release*, AEP Ohio President Marc Reitter said the ruling would support the state's growing tech sector and keep the industry in the U.S. while protecting other customers from shouldering the costs of providing power to it.

"I am grateful for the collaboration of all the parties involved in this filing, which ultimately brings clarity and certainty for infrastructure planning," he said. "We are looking forward to ending the moratorium and continuing to support development of more data centers in our service territory." ■

RA Technical Conference Comments Urge a Variety of Market Reforms

By James Downing

Concerns about PJM and the growth of data center demand dominated the comments received by FERC after its recent technical conference on resource adequacy (*AD25-7*).

The two-day technical conference in June focused on all of the organized markets under FERC jurisdiction, but PJM took up the most time. (See *FERC Dives into Thorny Resource Adequacy Issues at Technical Conference*.) Post-conference comments were made available July 7.

PJM's Independent Market Monitor said continuing with the status quo will mean "a massive wealth transfer" from other consumers as market prices spike almost entirely due to the needs of data centers. The IMM offered a way to avoid that.

"That solution is to require large data center loads to bring their own generation," the IMM said. "It is essential to have a pragmatic market solution that is consistent with and sustains efficient and competitive PJM markets rather than to create the conditions for a return to cost-of-service regulation."

That "bring your own generation" would have to have locational and temporal characteristics that meet the data center's load profile.

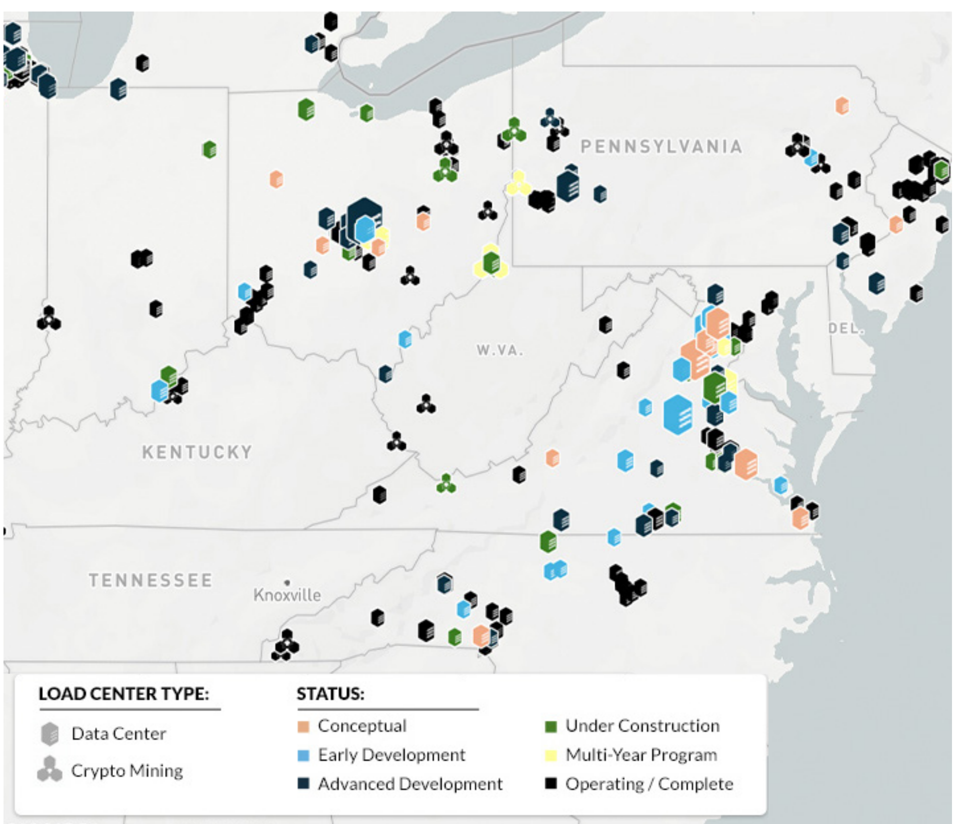
Some states are considering withdrawing from PJM's markets or returning to cost-of-service regulation to address the gap between growing demand and new supplies being too slow to materialize. (See *N.J. Mulls PJM Withdrawal amid Energy Shortfall Predictions*.)

Data center demand was responsible for $9.3 billion, or a 174.3% increase in the 2025/26 base residual auction (BRA). Absent reforms, those high prices will continue despite their political unsustainability.

"Data center load growth is the core reliability issue facing PJM markets at present," the IMM said. "There is still time to address the issue, but failure to do so will result in very high costs for other PJM customers and could also result in a switch from competitive markets to cost-of-service regulation."

Why This Matters

FERC's recent technical conference on resource adequacy addressed the biggest issue facing the industry. Post-conference comments gave parties another round to propose potential solutions to maintain reliability in an affordable way.



A Yes Energy produced map shows existing and proposed data centers in PJM. | v

Regardless of what the states do, PJM has a rule that has never been deployed, as its BRAs have always met the target reserve margin. If it were to fall short three delivery years in a row, it would start offering generators 15-year cost-of-service contracts. The idea of shortening that trigger from three years has been suggested by some stakeholders, the IMM said.

"Implementation of such long-term cost-of-service contracts would undermine competitive markets and suppress prices for competitive entrants because the backstop capacity is required to be offered in the capacity auctions at zero price," the IMM said.

Constellation Energy, an independent power producer and competitive retailer that is competing to serve data center load, pushed back on the "BYOG" proposal, arguing it would discriminate against large consumers.

"Any suggestion that some load growth should be addressed efficiently through PJM's capacity market, but large load should be subject to a bring-your-own-generation requirement makes little sense; it is unclear why the existing capacity market is the efficient vehicle to incentivize needed investment for some types of load but not others," Constellation said. "Further, this requirement will distort competitive capacity market prices and result in inefficient long-run price signals. This outcome will likely result in less efficient investment decisions and higher overall costs for wholesale electric customers."

The Federal Power Act says FERC must avoid "undue discrimination," and the IMM argued the BYOG proposal falls short of that.

"It is not unduly discriminatory to identify the class of large data centers and impose requirements on that class that match the impact of that class on all other customers," the IMM said. "It would be unduly discriminatory to all other customers, from the smallest residential customer to the largest industrial customer, to allow large data centers to add massive amounts of load to the system with resulting price impacts and reliability impacts on those other customers. Preventing undue discrimination requires that data center loads bring their own new generation."

Constellation argued the proposal would affect existing generation because those deals are not likely to be reflected in the capacity market price, and that will distort its signals. For that reason, however, the firm agrees with the IMM on utility-owned generation.

"Likewise, requiring utility ownership of new generation in market regions will negatively impact market performance and impose unnecessary costs and risks on wholesale electric market consumers," Constellation said.

Constellation wants to see more facilitation of long-term bilateral contracting to hedge resource adequacy risk. It also argued for improved load forecasting and improvements to energy market price formation so markets can be as effective as possible.

Dominion Energy Resources owns one of the largest vertically integrated utilities in PJM. Its zone includes rural cooperatives and also is home to the largest concentration of data centers in the world. Winter and summer peaks are expected to grow at 4.7% and 4.9%, respectively, on an annual, compound basis in the coming years.

The capacity market is at risk of falling short of meeting the demand from load-serving entities (LSEs).

"LSEs are forecasting the interconnection of significantly large amounts of new load while expecting the BRA to bring on sufficient new capacity in time to serve that load," Dominion said. "The current rules simply do not require such LSEs to themselves do anything to ensure that most of the capacity will 'be there.' This deviation from the original intent of the market design is stressing the system."

Dominion wants FERC to establish obligations for LSEs to provide a certain amount of generation or other capacity supply to serve their load — making the BRA a true residual market. It also suggested strengthening the fixed resource requirement self-supply alternative and moving to more seasonal auctions.

The Edison Electric Institute made the point that the load growth, which has grown to levels unseen for decades and has disrupted resource adequacy plans around the country, has its good side.

"This load growth is a positive development for the United States and holds the potential to create economic benefits for all customers over the long term," the investor-owned utility trade group said. "The electric grid provides an extraordinary platform to deliver resilient, reliable power to address customer needs on a large scale. To accommodate current and future growth, as well as maximize benefits, new and proactively planned energy infrastructure of all types will be required."

FERC has its role in getting the wholesale market design correct, but it must work with states, LSEs and others to deal with the issue.

"States' authority includes control over in-state facilities used for the generation of electric energy, whereas the commission has exclusive jurisdiction over wholesale sales of electricity in the interstate market," EEI said. "Given their jurisdictional authority with respect to generation resources, states will have a central role in identifying and implementing needed changes.

"However, the commission must recognize that state commissions have elected to exercise their jurisdiction over generation resource adequacy differently — some state commissions directly exercise authority over generation resource adequacy issues, while others rely primarily on regional reliability councils or RTOs/ISOs."

Advanced Energy United, the American Clean Power Association, the American Council on Renewable Energy and the Solar Energy Industries Association agreed that states are important to solving the issue.

"When allowed to function as designed, and when coordinated with state policies and resource planning processes, competitive markets remain an effective and efficient tool to ensure resource adequacy," the clean energy trade groups said. "Across the RTOs/ISOs, there are multiple approaches to meeting resource adequacy needs — from centralized and hybrid markets to non-market approaches — any of which can help ensure sufficient resources for a reliable grid. It is not market *failure,* but the failure to let markets *function* that threatens resource adequacy."

Existing resource adequacy constructs can be improved incrementally to increase their transparency, accuracy, granularity and durability. Those changes will improve the chance for more bilateral contracting to take pressure off the centralized markets, they said.

"Bilateral contracts are an essential tool for resource adequacy: they offer longer-term certainty to new resources than a three-year forward or prompt auction for a single delivery year can, and are therefore important for facilitating investment in the new resources needed to support resource adequacy," the clean energy trade groups said. "States can play a key role in enabling and encouraging more bilateral contracting, but stable, predictable, transparent markets are a critical foundation without which more robust, efficient contracting cannot occur."

While incremental reforms are needed, the trade groups urged caution against rushing the process and relying too heavily on quick fixes.

"Urgency constrains optionality and accurate analyses, which as a result often leads to sub-optimal solutions," the four groups said. "For example, short-term fixes imposed in a rush to mitigate the effects of market prices will only deepen uncertainty and cause further harm by negating the role that market prices can play in stimulating entrance of new capacity." ■

PJM Reviews June Heat Wave

By Devin Leith-Yessian

PJM saw its highest peak loads in over a decade during a heat wave that stressed the Mid-Atlantic region from June 22 to 26. (See *PJM Exceeds Forecast Summer Peak Load During June Heat Wave*.)

The region saw a preliminary integrated hourly peak load of 162,401 MW on the afternoon of June 24, its third highest ever summer peak. The next day followed up with a peak of 161,770 MW. Those figures include demand response deployments, which included all available long and short-lead resources on that day.

The RTO prepared for the heat by issuing a recall on generator maintenance outages between June 21 and 26 and a hot weather alert starting one day later. As the temperatures rose, maximum generation and load management alerts were issued for June 23 to 25, coinciding with pre-emergency DR deployments.

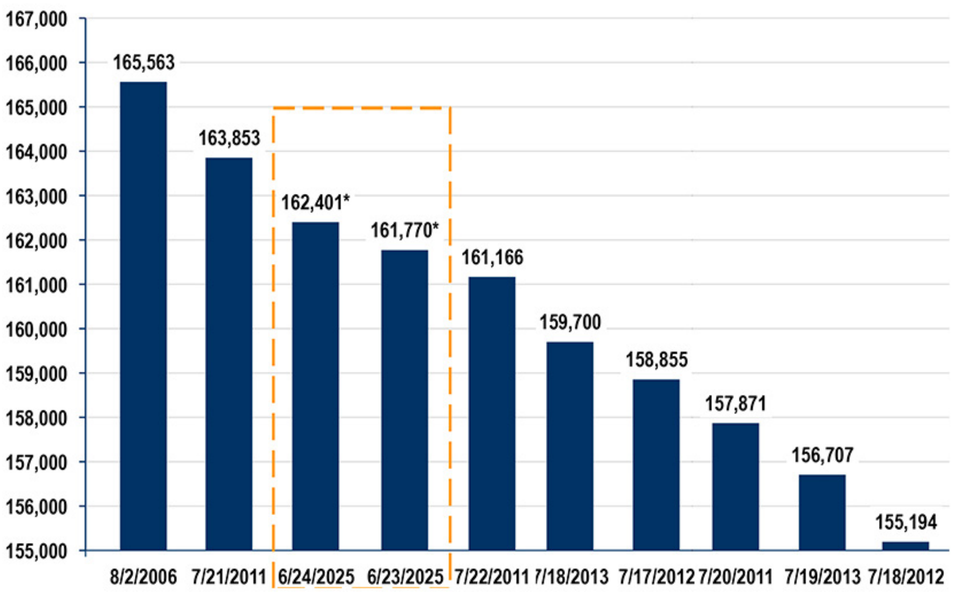
PJM's Kevin Hatch *told* the Operating Committee on July 10 that summer risk continues to be driven by peak loads like those seen during the heat wave, the scale of which have been offset by increasing solar penetration. As those resources go offline, increased importance is being placed on the evening ramp, and overall intermittent penetration has required more flexibility, with wind availability varying day-to-day.

Director of Operations Planning Dave Souder said much of the generation interconnection queue is solar, which could lead to reliability risks continuing to be concentrated in the winter, where gas availability and low temperatures are the drivers of system strain.

Stakeholders asked whether PJM experiences a decline in DR availability in the evening when many businesses begin switching machines off at the end of the work day. Hatch said PJM gets updates from curtailment service providers throughout the day and has not seen a decline in evening availability.

Why This Matters

PJM saw two of its highest ever peak load days during the June heat wave but avoided emergency conditions with demand response deployments. The RTO told stakeholders that increased solar penetration could mitigate future summer peaks and continue a shift toward winter reliability risk.



The June heat wave saw two days that placed in the top five peak loads PJM has experienced. | *PJM*

The average resource outage rate across the heat wave was 9.65%, the bulk of which were from plant equipment failures. A relatively smaller amount were from environmental restrictions. Hatch said the heat wave fell closer to the close of the spring maintenance season than past summer events, contributing to some of the outages.

PJM's Brian Chmielewski *told* the Market Implementation Committee on July 9 that high load, reserve shortages and congestion pushed the system marginal price to peak at $3,700 on June 24, $3,011.96 the day prior and $2,358.36 on June 22.

Congestion peaked on June 24, with 12 out of 13 binding constraints in real-time security-constrained economic dispatch, but Chmielewski said congestion played a smaller role in pricing than in recent winter storms. The heat wave saw around half the binding constraints that were seen during the Martin Luther King Jr. Day winter storm, he said. ■

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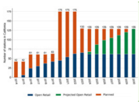
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PJM Monitor Calls for Bidding Limits on NRG Generation, DR in LS Deal

By James Downing

PJM's Independent Market Monitor told FERC on July 7 that NRG Energy's proposed purchase of power plants and demand response from LS Power would increase structural market power in the RTO (*EC25-102*).

The Monitor asked for the commission to impose behavioral constraints on the proposed merger, which includes assets in other markets, though the biggest overlap is PJM. (See *NRG Energy Seeks FERC Approval for LS Power Deal*.)

"The transaction would increase structural market power in PJM markets," the Monitor said. "The significant increase in the concentration of ownership of emergency and pre-emergency demand resources is especially noteworthy given the newly pivotal role of these resources and the absence of any applicable market power mitigation rules."

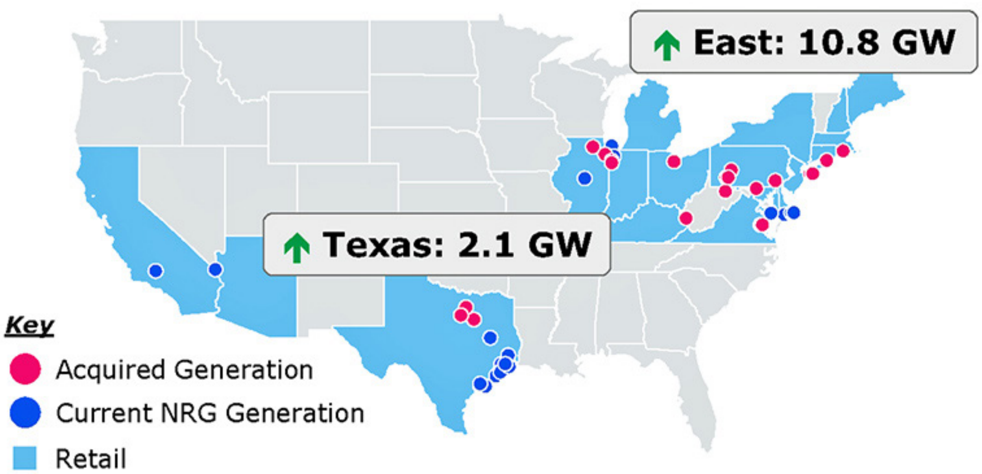
DR does not have a must-offer obligation, which allows for physical withholding and no offer caps, allowing for economic withholding, according to the IMM.

"This absence of market power mitigation rules is much more significant now than ever before in the history of the PJM capacity market as a result of the fact that demand resources are included in the reserve margin for the first time ever in the 2025/2026 delivery year," the Monitor said. "The PJM capacity market would have been short of meeting the reliability requirement in the [Base Residual Auction] for 2025/2026 but for these demand resources."

The behavioral commitments would ensure competitive behavior on behalf of NRG and be applied uniquely to the firm's portfolio of emergency and pre-emergency demand resources. The Monitor said the conditions were warranted because of their "extreme increase in concentration."

The IMM listed nine commitments in its filing that NRG should follow to ensure its bids are competitive even with the higher market power once the deal closes.

- All resources should develop cost-based offers using a fuel-cost policy that passes the IMM's review and are limited to just $1/MWh of markup.
- All resources should be required to refrain from using crossing price and cost-based energy market offer curves to ensure no price-based offers with high markups will be dispatched by PJM.
- All operating parameters should be based on physical limits as defined in PJM's tariff.
- NRG should have to agree to only retire power plants when they become uneconomic, meaning avoided costs are expected to exceed projected revenues.
- The company should have to bid into the capacity market at prices that do not exceed net avoidable costs to ensure that market offers stay competitive, even if PJM changes its rules.
- It should have to bid all supply at its full installed capacity of all its cleared unforced capacity megawatts into the day-ahead and real-time markets.
- NRG should be required to base its energy offers, including the pre-emergency and emergency DR strike price, on the documented cost of dispatch and all its capacity offers on the net avoidable cost of the resources' participation in DR programs.
- All emergency and pre-emergency demand resources should be offered in the capacity market following the transaction.
- NRG should commit to not removing resources from PJM's markets for co-location deals until final rules are developed by FERC to ensure continued competitive results in the wholesale markets. ■



(GW)	NRG		Portfolio Acquisition		Pro Forma
Generation	11.9	+	12.9	=	24.8
C&I VPP	2.0[1]	+	6.0	=	8.0

NRG Energy acquisitions | *NRG Energy*

PJM OC Briefs

1st Read on Manual Revisions Detailing Generation Deactivation Process

PJM's Michael Herman presented revisions to Manual 14D: Generator Operational Requirements to reflect the deactivation process stakeholders approved in January.

The changes are set to be voted on by PJM's Operating Committee on Aug. 7, followed by the Markets and Reliability Committee on Aug. 20. (See "Stakeholders Endorse Changes to Generator Deactivation Requirements," *PJM MRC/MC Briefs: Jan. 23, 2025*.)

The changes would require resource owners intending to retire a unit participating in the capacity market to provide PJM with at least one year's notice before the desired deactivation date, while resources not participating in the capacity market would have to follow the notification process for seeking an exemption from the requirement that they must offer into the market.

The proposal would also remove the $2 million cap on project investments allowed in the deactivation avoidable cost credit, limit the yearly adder for investments to 10% and remove language causing the credit to be determined through the daily deficiency rate rather than the deactivation avoidable cost rate (DACR) when the DACR and applicable multiplier exceed the deficiency rate.

The proposal aims to increase transparency around reliability must-run (RMR) agreements by requiring resource owners to submit expected costs to be recovered to the Independent Market Monitor and PJM, which will publish the information. The Monitor will also publish market power letters, and notifications will be sent to stakeholders regarding RMR arrangements.

PJM Initiates Black Start Reliability Backstop Process

PJM has opened communications with transmission owners under the black start reliability backstop process to determine if a third request for proposals (RFP) is needed to secure at least one fuel-assured resource for each zone.

PJM's Ray Lee *told* the OC there are several zones without a fuel-assured black start resource following repeat RFPs, although a final count has not been

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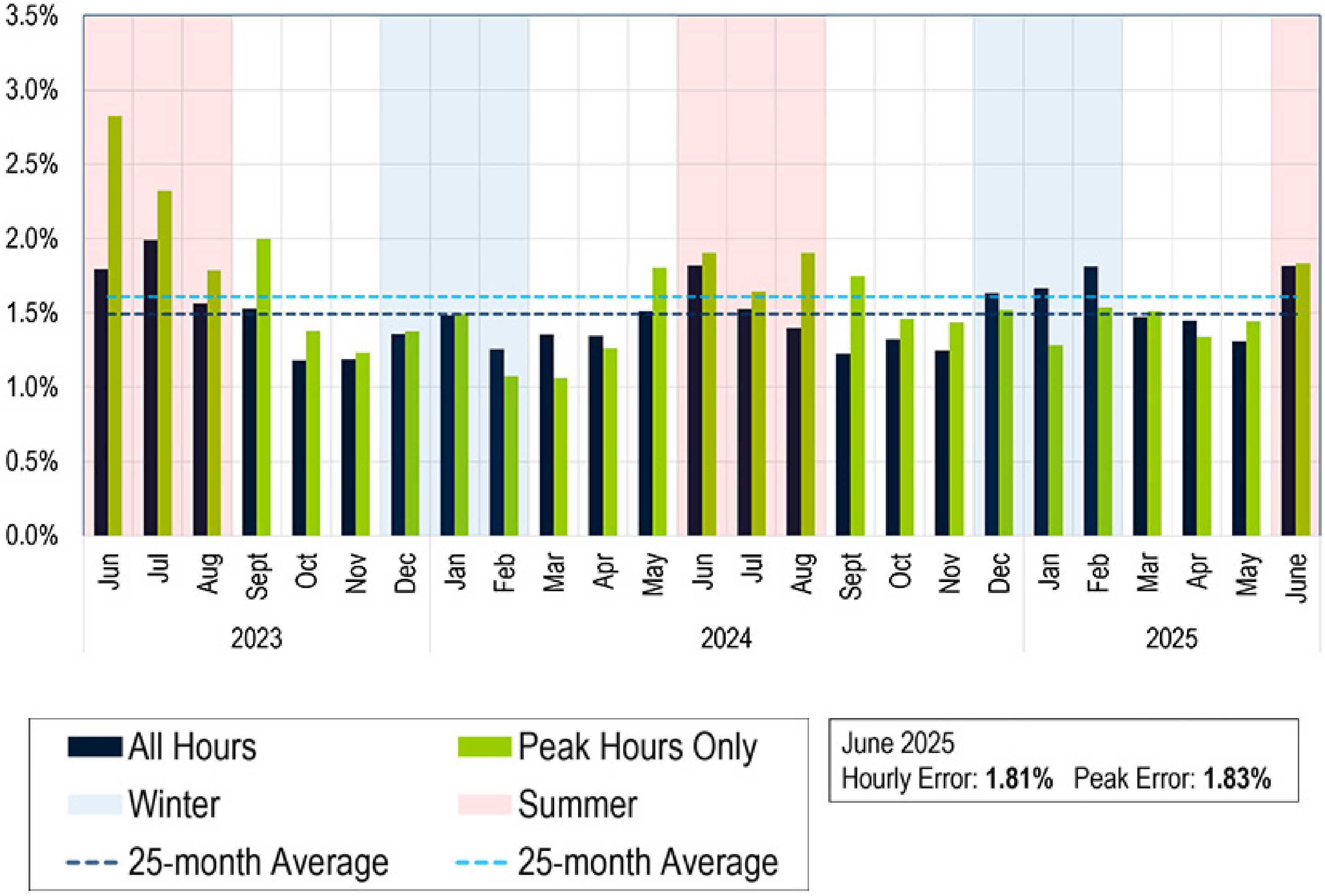


PJM presented its average and peak load forecast error for June to the Operating Committee. | *PJM*

PJM MIC Briefs

Stakeholders Endorse Changes to Storage Participation in Regulation Market

The Market Implementation Committee endorsed by acclamation a PJM proposal to allow demand response resources with behind-the-meter storage to participate in the regulation market when there is the capability for energy injections. (See "PJM Presents Education on Demand Response in Regulation Market," *PJM MIC Briefs: June 2, 2025*.)

The proposal would allow DR customers to participate as regulation-only resources when there is no load or a net injection at the point of interconnection, so long as they've received authorization from the relevant electric distribution company and it's reflected in a net energy metering agreement.

The change is part of PJM's wider proposal to comply with FERC Order 2222, which is set to be effective Feb. 2, 2028 (*RM18-9*).

Jay Marhoefer, CEO of Intelligent Generation, said tariff changes by certain EDCs that allow behind-the-meter storage to participate in the regulation market while injecting had the unintended consequence of voiding the PJM — and FERC-endorsed — process for allowing injection, either through a PJM interconnection service agreement (ISA) or wholesale market participation agreement (WMPA).

Marhoefer said the proposal would recognize that certain utilities want to encourage regulation participation and can settle the injection. "There's no engineering issue, there's no technical issue, this is strictly an accounting issue," he said.

Independent Market Monitor Joe Bowring opposed the proposal as a one-off benefit to a small subset of market participants and argued that if the commission had intended for elements of PJM's compliance filing to be implemented earlier, it would have reflected that in its order.

Monitoring Analytics President Joe Bowring | © *RTO Insider*

PJM Presents Manual Revisions for Regulation Market Redesign

PJM presented a first read on a slate of manual revisions to conform with FERC's approval of a redesign of the RTO's regulation market (ER24-1772). The changes to the regulation market create one price signal with resources offering regulation up and down products, replacing a model with Regulation A for long deployments and Regulation D for fast response and bidirectional products offered by market participants. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Dec. 20, 2023*.)

The *changes* to Manual 11: Energy & Ancillary Services Market Operations add detail to offer structure, DR participation, how regulation range limits affect resource clearing and lost opportunity cost (LOC) credits. PJM's Joseph Tutino said the changes essentially create a new Section 3, expanding it by eight subsections.

The Manual 15: Cost Development Guidelines *revisions* specify that cost increases for variable operations and maintenance (VOM) are zero for regulation resources also participating in the energy market, as those costs are recoverable in energy offers. It also updates references to regulation performance to instead read as regulation mileage.

The Manual 28: Operating Agreement Accounting *changes* include the formula for the regulation clearing price credit and how shoulder interval opportunity costs are determined.

1st Read on Real-time Renewable Dispatch

PJM's Vijay Shah presented a first read on a *proposal* to create a new Effective EcoMax parameter for wind and solar resources for dispatch in the real-time energy market. The proposal is set to be voted on by the MIC at its Aug. 6 meeting, followed by the Markets and Reliability Committee on Sept. 25 and Members Committee on Oct. 23. A FERC filing is envisioned in November or December. (See "2 Renewable Dispatch Packages Advance to MIC," *PJM MIC Briefs: June 2, 2025*.)

The parameter would use a forecast value of the resource's capability for each 5-minute interval, which is intended to better reflect how a unit will perform than the existing Eco Max parameter. Shah said PJM's security-constrained economic dispatch (SCED) is limited to dispatching resources up to Eco Max, which can prevent them from being set at their full output.

Resources would be limited to ramping up to 20% of their installed capacity (ICAP) per minute to minimize volatility, which Shah noted still would allow them to increase to 100% in a 5-minute interval.

The proposal would retain curtailment flags for wind resources and establish them for solar as well. Curtailment flags for all resources are set to be removed in July. However, a Distributed Resources Subcommittee (DISRS) poll found 96% support for a variant of the proposal retaining them for renewables.

During the June 2 MIC meeting, Shah said eliminating curtailment flags would require generation owners to follow their basepoints and avoid situations where intermittent resources with low marginal costs are curtailed because their bid-in parameters are lower than actual output, resulting in higher-cost units being committed.

Monitor Proposes Rewrite of Offer Capping Issue Charge

The Independent Market Monitor proposed revisions to a *problem statement* and *issue charge* exploring how resources scheduled in advance of the day-ahead (DA) market have their offers capped to widen their scope to include transparency on how those resources are committed, how the commitments are communicated, which offers are used and how uplift is calculated, among other things. The original problem statement and issue charge were sponsored by PJM and supported by the Monitor in February.

The changes add four key work activities to the issue charge:

- education on how PJM schedules resources ahead of the DA market, including triggers for those commitments, how market participants are notified, commitment instructions, inputs and models used to determine commitments, and constraints not included in unit parameters;
- consideration of more transparency on the process for advance commitments;
- updating the uplift calculation for units with multi-day commitments; and
- determining how units with advance commitments are treated in the DA market.

Joel Romero Luna, market analyst with the Monitor, said the rules should be specific about the commitment instructions so generators know the amount of gas a resource should be procuring for a specific commitment. Leaving the instruction unclear can lead to resource owners buying more gas than needed and being compensated for fuel not used or can lead to resource owners not buying enough gas to match PJM's expectations. ■

— Devin Leith-Yessian

PJM OC Briefs

Continued from page 48

completed yet. He said staff wanted to provide stakeholders with notice that the process has been started as early as possible.

The dialogue with transmission owners is the first step of the backstop, which can either result in an RFP where transmission owners in zones lacking a fuel-assured resource are required to submit a proposal or PJM actively monitoring the shortage. If an RFP with mandatory proposals is held, PJM will select the best proposal, and the transmission owners must make a Section 205 FERC filing.

June Operating Metrics

PJM in June *experienced* an average hourly load forecast error rate of 1.81% and a peak error of 1.83%, with five days outside its 3% peak error rate benchmark.

The peak on June 13 was a 4.01% overforecast due to temperatures coming in 6 to 8 degrees Fahrenheit cooler than expected, while the June 27 peak was 7.11% overforecast with a multiday heat wave ending as temperatures fell by as much as 12 degrees.

The June 7 peak was 3.75% underforecast with temperatures 4 to 5 degrees higher than predicted, while unexpected heat and humidity on June 8 contributed to a 3.5% underforecast. The June 10 peak was 4.67% underforecast due to high temperatures and humidity.

The month saw one spin event, four shared reserve events, three maximum generation emergency alerts, 12 pre-emergency load management reduction actions, one high system voltage action and two hot weather alerts issued. There were 69 shortage cases approved between June 22 and 25, as well as on June 30.

The spin event occurred June 22 at 7:37 p.m. and lasted 7 minutes and 46 seconds. There were 1,907 MW of generation assigned with 56% responding and 418 MW of demand response (DR) assigned with 65% responding.

Periodic Review of Manual 13

PJM *presented* a set of revisions to Manual 13: Emergency Procedures drafted through the document's periodic review.

The revisions codify PJM's practice of conducting two voltage reduction action tests each year and add detail to its manual load dump action, including specifying that members should identify critical gas infrastructure that could impact generation capability.

The language clarifies that pre-emergency DR deployments are not a trigger to enter NERC Energy Emergency Alert Level 2 and removes a reference to an outdated NERC standard limiting the amount of contingency reserves consisting of interruptible load to 33%. It also specifies that PJM will curtail non-pseudo-tied exports as needed when it issues a primary reserve warning, emergency load management reduction action or maximum generation emergency action. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse POI Jurisdiction Changes

The Planning Committee endorsed by acclamation a PJM *proposal* to rework how it determines the jurisdiction a resource point of interconnection (POI) falls under in an effort to designate more low-voltage facilities as being under state jurisdiction. (See *PJM Proposes Changes to Determination of Jurisdiction over Generation*.)

The proposal would establish a "bright-line test" where resources interconnecting to facilities below 69 kV would be designated state jurisdictional and required to obtain a wholesale market participation agreement (WMPA). Higher-voltage POIs would be required to receive a generation interconnection agreement (GIA). There also would be a backstop mechanism where jurisdiction could be assigned regardless of voltage depending on how the transmission owner, FERC or relevant electric retail regulatory authority has defined the cost-recovery method.

The current first-use paradigm designates the first resources interconnecting to a distribution facility to participate in PJM's markets as state jurisdictional and all subsequent interconnections as falling under federal jurisdiction. If the proposal had been implemented when the WMPA pathway was first established, PJM Associate General Counsel Thomas DeVita said about 12 to 15% of projects that received an interconnection service agreement (ISA) or GIA would have gotten a WMPA instead.

During the June 3 first read on the proposal, DeVita said the aim of the proposal is to focus the GIA process on more complicated applications to high-voltage facilities which take a greater number of staff hours to study, while continuing to have visibility into distribution-level interconnections.

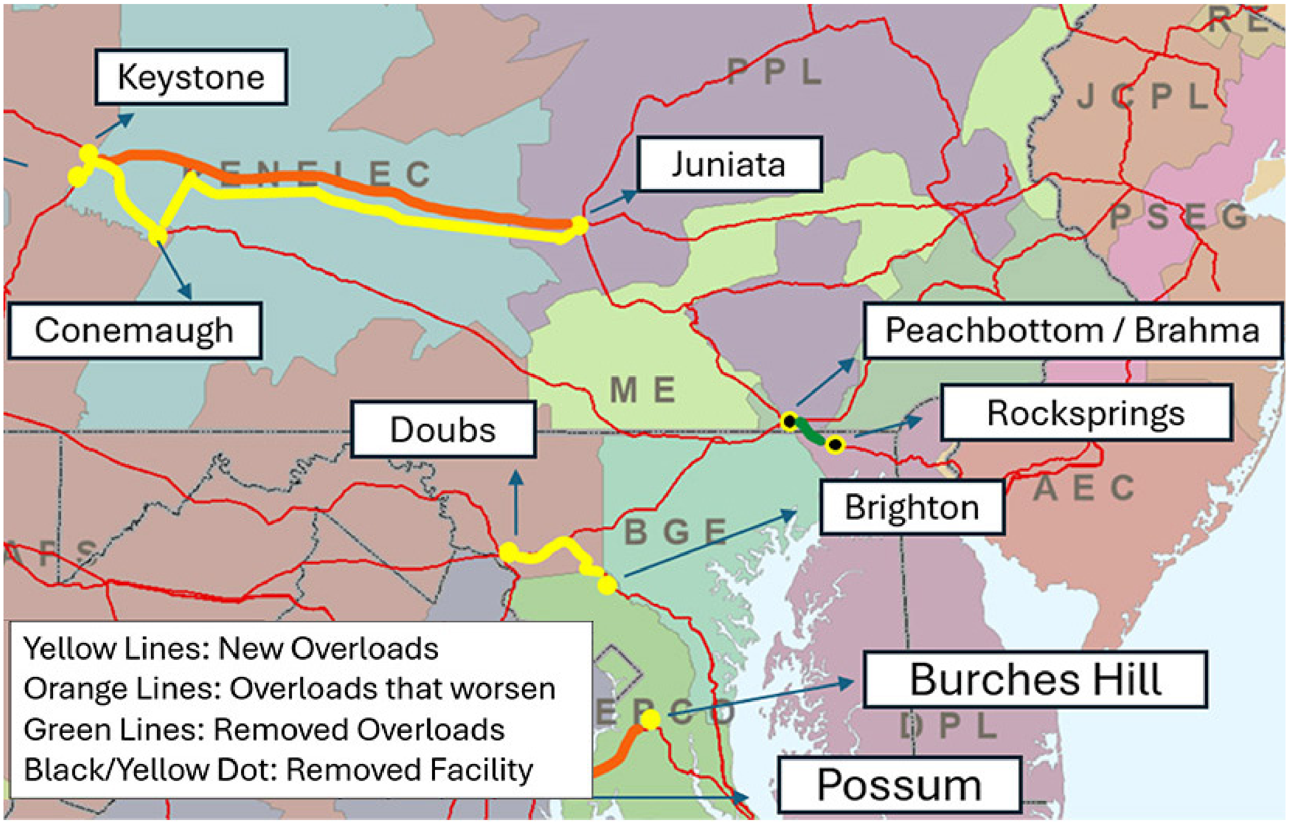
PJM Vice President of Planning Jason Connell said system impact studies for a generator pursuing a WMPA are completed by electric distribution companies rather than the RTO and produce a simpler agreement for it to process.

1st Read on ELCC Manual Revisions

PJM's Josh Bruno presented a first read on *revisions* to PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability to codify FERC's approval of a proposal the RTO filed to establish two new resource classes for accreditation under the effective load-carrying capability (ELCC) process (*ER25-1813*). (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

The changes add the oil-fired combustion turbine and waste-to-energy steam classes as discrete categories for resource accreditation, starting with the 2027/28 Base Residual Auction. Oil generation was included in the miscellaneous "other unlimited resource" category, while waste-to-energy was modeled under "steam" generation.

Following the March 19 Markets and Reliability Committee meeting, Bruno told *RTO Insider* that breaking oil combustion turbines out as a separate class allows PJM to better capture the types of correlated outages that tend to affect them and provides the ELCC modeling



A PJM map shows overloads on several 500-kV lines identified in a scenario removing offshore wind development in New Jersey and Delaware from its bulk power flow modeling. | *PJM* with more performance data than if each unit was looked at individually.

PJM Recommends Sunsetting Relay Testing Subcommittee

PJM's Stan Sliwa presented a first read on *revisions* to the Relay Subcommittee (RS) charter to sunset the Relay Testing Subcommittee and include its activities in the RS. The proposed language also would clarify who is able to participate in the RS, which is limited to members who have signed the Operating Agreement and are transmission or generation owners in PJM.

Transmission Expansion Advisory Committee

Update on 2025 RTEP Window 1

PJM has published an addendum to the problem statement and study files for its 2025 Regional Transmission Expansion Plan Window 1, which opened for developers to submit solution proposals on June 18 with an Aug. 18 deadline.

An additional scenario was added to the 2032 base case modeling the expected bulk transfer if offshore wind developments in New Jersey and Delaware are not completed. Removing that generation from the modeling resulted in overloads on the South Bend-Keystone 500-kV, Keystone-Conemaugh 500-kV, Conemaugh-Juniata 500-kV, Brighton-Doubs 500-kV, Keystone-Juniata 500-kV and Burches Hill-Possum Point 500-kV lines.

Removing the offshore wind also resolved overloads on the Rock Springs-Bramah 500-kV line and Peach Bottom 500-kV bus identified in other scenarios.

PJM's Wenzheng Qiu said removing the projects increases power flows from west to east and from south to north, which will be considered in evaluating the robustness of projects submitted in Window 1.

PJM also updated the window's problem statement to reflect that no major regional transfer issues were identified in the 2030 base case. However, several high-voltage overloads were found in the seven-year case.

Staff chose not to include clusters with overloads on the AG1-125-Marysville 765-kV line and the 765-kV corridor between Wilton Center and Marysville due to the lines being limited by equipment. Multiple overloads on the 500-kV network in the Mid-Atlantic Area Council region also were not included as they are not present aside from the scenario removing the offshore wind developments.

PJM did include a pair of overload clusters in the Columbus, Ohio, region where N-1-1 analysis found widespread local system voltage issues expected to worsen with load growth forecast to continue beyond the seven-year horizon.

Overloads on the 138-kV and 115-kV networks ATSI along the East Springfield-Melissa-London corridor were included.

Supplemental Projects

Duke Energy *presented* a $186 million project to serve a customer planning to bring 800 MW of load to Butler County, Ohio, by 2030. It would proceed in four phases, starting with tapping into the Miami Fort-Woodsdale 345-kV line to provide initial service for about 300 MW of load. The first phase will be paid for by the customer.

Next, Duke will build a 345-kV substation, named Wayne-Madison, at the customer's location to be looped into the Woodsdale-Miami Fort line. It will be looped in with about one mile of new transmission at a cost of $40 million for the second phase, which is envisioned to be complete by the end of 2028.

The third phase involves building a new Cotton Run substation cutting into the Miami Fort-West Milton 345-kV line and connecting to Wayne-Madison with a new 5.5-mile 345-kV circuit. The third phase is estimated to cost $45 million and to be done by June 2029.

The project will complete with the rebuilding of the 138-kV Port Union-Toddhunter double circuit line to upgrade one side of the line to 345-kV, with corresponding equipment installed at Port Union. This phase is estimated to cost $101 million and be complete by the end of 2030.

FirstEnergy *presented* a $344 million project to rebuild its 69-mile Sammis-Star 345-kV line due to the towers failing wind and ice load tests. It has 22 wood pole H-frame and 375 steel lattice towers along its length, and a tornado left 13 towers destroyed in a cascading failure. The project is in the conceptual phase with a possible in-service date of May 30, 2031.

The utility presented another three projects to repair lines experiencing degradation and end-of-life issues. A $74 million project would rebuild 14.5 miles of the Niles-Shenango 345-kV line, repairing wood poles and reconductoring. A $53 million project would replace 33 steel towers along the double circuit 345-kV corridor between the Beaver Valley, Hanna and Mansfield substations and reconductor about 13.5 miles. A $21 million project would rebuild elements of the Bayshore-Davis Besse 345-kV line.

Dayton Power and Light *presented* several needs to serve new customers across Ohio. Some of the load is expected to begin coming online in the next few years, scaling to about 1.6 GW by 2030.

PPL *presented* a need to serve a customer seeking 230-kV service for 1.5 GW of load near Gouldsboro, Pa. The customer is expected to come online in 2027 drawing 300 MW and scale to its full consumption by 2030.

PSEG *presented* a $27 million project to reduce network strain on the Newark switching station by installing two 230/13-kV transformers at the nearby McCarter switching station and transferring several circuits to that facility. The project is in the conceptual phase with a possible in-service date in December 2029.

Dominion *presented* a $54 million project to rebuild three lines nearing the end of their useful life: the 30-mile Chesterfield-Lanexa 115-kV line, 14.6-mile Chesterfield-Chickahominy line and 14.2-mile Chickahominy-Lanexa 230-kV line. The Chesterfield-Lanexa line would be built to 230-kV standards but operate at 115 kV, while the other two lines would remain rated for 230 kV. Equipment at the substations also would be upgraded. The project is in the engineering phase with an expected in-service date of Dec. 31, 2028.

Several stakeholders requested that TOs presenting supplemental projects intended to serve large loads specify whether those consumers have been submitted to PJM as large load adjustments to its annual load forecasts. ■

– Devin Leith-Yessian

D.C. Circuit Declines Review of SPP Cost Allocation

By Tom Kleckner

The D.C. Circuit Court of Appeals has denied a review of a FERC decision that allowed SPP to incorporate some Missouri transmission facilities into one of its pricing zones, spreading the costs of the newly integrated infrastructure across the zone's customer base (*23-1133*).

The court ruled July 11 that FERC "reasonably applied" the cost-causation principle in approving SPP's tariff revision to include the annual transmission revenue requirement for the city of Nixa's facilities in the RTO's pricing Zone 10. Nixa's 10 miles of transmission lines and substations are owned by GridLiance High Plains.

Writing for the court, Circuit Judge Justin Walker said the commission determined that the Nixa assets brought "integration, reliability and power transfer benefits to Zone 10 customers" that justified spreading the costs across the transmission zone.

"FERC may analyze costs and benefits at the zonal level rather than the customer level, and FERC reasonably determined that all the zone's customers will enjoy benefits," he said. "Because of those zone-wide benefits, it was reasonable for FERC to spread the integration's costs to all the zone's customers."

The appeal was brought forward by the Arkansas city of Paragould's Light & Water Commission and other parties, several of whom unsuccessfully requested FERC rehear its 2023 order approving SPP's tariff revision (*ER18-99-007*). (See "City of Nixa, Mo., Annual Transmission Revenue Requirement," *FERC Briefs: Orders Addressing Arguments Raised on Rehearing*.)

The utility objected to FERC's level of generality in considering benefits, the type of benefits considered and the case's evidence of benefits. The court rejected each of the objections.

Walker said FERC had no duty to "take such a hyper-granular approach to weighing costs and benefits" and that it "reasonably analyzes costs and benefits at the zonal level" when considering integration of new facilities in the zonal system.

"As a significant customer in Zone 10, Nixa has paid a considerable share of Zone 10 transmission facility costs — a share that includes costs for facilities that primarily serve load to non-Nixa customers," Wright wrote. "So, even though Nixa itself does not draw direct, quantifiable benefits from these facilities, it has footed part of the bill. In sum, the petitioners want Nixa to keep paying a substantial percentage of the costs of facilities that directly serve non-Nixa areas of Zone 10, while the petitioners themselves pay no part of the facilities that directly serve Nixa."

The D.C. Circuit found that as it and other circuit courts have held, "benefits justifying a cost shift do not need to be tangible, nor must they be amenable to precise tabulation." It said it is enough that there is "an articulable and plausible reason to believe" the integration's benefits are "roughly commensurate" with the integration's costs.

The court also said the claim that FERC did not have sufficient evidence to conclude that integrating the Nixa assets would provide any benefits to non-Nixa customers faced "a high bar."

"FERC's decisions need only be supported by 'substantial evidence,' which is 'more than a scintilla' but 'less than a preponderance,'" Walker wrote.

The petitioners argued their case before Walker and fellow Circuit Judges Florence Pan and Cornelia Pillard in April 2024. ■

Nixa, Mo. | *City of Nixa*

SPP REAL Team Endorses Demand Response Framework

By Tom Kleckner

SPP's Resource Energy and Adequacy Leadership (REAL) Team endorsed RTO staff's framework for demand response during a special meeting, allowing the grid operator to bring it forward to the quarterly governance meetings in July and August and to then begin drafting the tariff change.

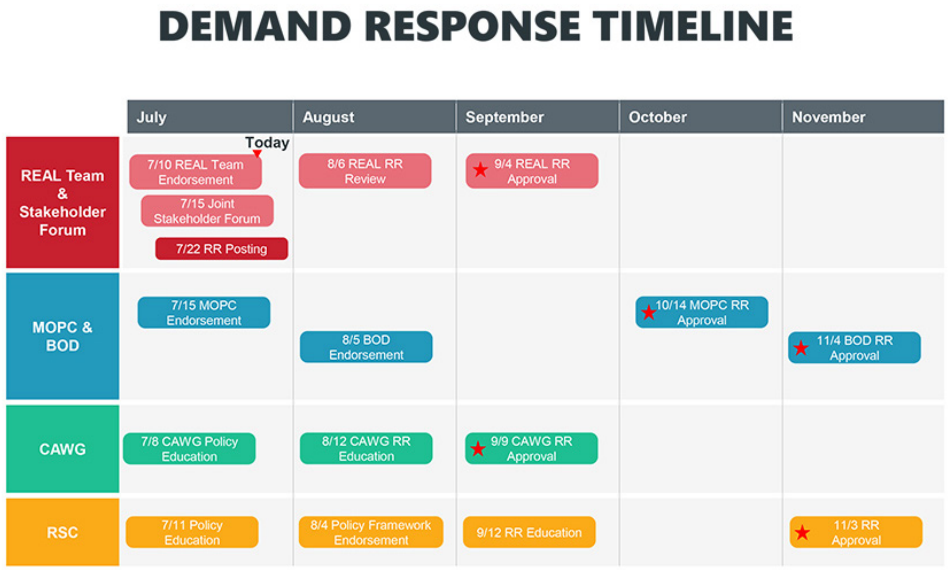
The framework includes various metrics, criteria and thresholds for both reliability and market-registered demand response to reduce consumption during tight grid conditions. SPP has put together what it called a cohort team to gather feedback, including many of the RTO's working groups.

"We started talking about policy changes to 2017. … We're coming up on a decade before we implement changes," Natasha Henderson, SPP's senior director of grid asset use, said during the July 10 webinar. "That's kind of scary to think about, but because we have not been able to get consensus through our stakeholder process, the cohort team … helped drive some specific feedback and focused feedback."

The grid operator also scheduled a demand response engagement forum July 15 before the Markets and Operations Policy Committee to discuss the proposed policy and to gather additional feedback. MOPC will then take up the policy framework for its endorsement.

The *current framework* includes:

- no opt-out for Level 2 energy emergency alert (EEA) testing;
- moving the accreditation lookback from one year to three;
- authorized outages and 50% accreditation within the first year of tests for fully market-registered resources;
- a 100-hour cap for the EEA2 product;
- changing resource accreditation to be grossed up for the planning reserve margin and to allow partial accreditation; and
- a 1,700-MW limit based on the historical remaining capacity in real time, with the allocation method yet to be defined.



SPP's approval timeline for its demand response policy. | *SPP*

"We have a good structure," said Omaha Public Power District's Colton Kennedy, the Supply Adequacy Working Group's chair. "We've had concerns around specific details. I think staff has been very responsive in listening to those concerns."

SPP is considering an option to allow controllable load modifiers that are not accredited to participate in demand response. Kansas Commissioner Andrew French urged transparency into the load modifiers. He said earlier in the week, Kansas regulators had approved *Evergy's 50% stake into two new combined cycle plants*, a deal French said equates to $1.6 billion for 710 MW of capacity.

"So that's the cost of new capacity right now. It is extremely steep," he said. "We emphasized in our order it is really going to be important to look at alternatives and to make sure we are maxing out any opportunities for things like demand response as we see the capital costs increase."

French said load modifiers need to be visible to the balancing authority.

"If you get rid of that and make it non-transparent and it's just within the load forecast, there is a concern then that you're immediately increasing the amount of generation and reserves that a utility is going to have to build, unless the state regulator immediately works with them to make sure that they are calling on that to reduce their peaks," he said. "The other option is that it stays as a load modifier, subject to a lot of BA scrutiny. It makes me nervous to force it into being a registered resource. That's just a huge paradigm shift."

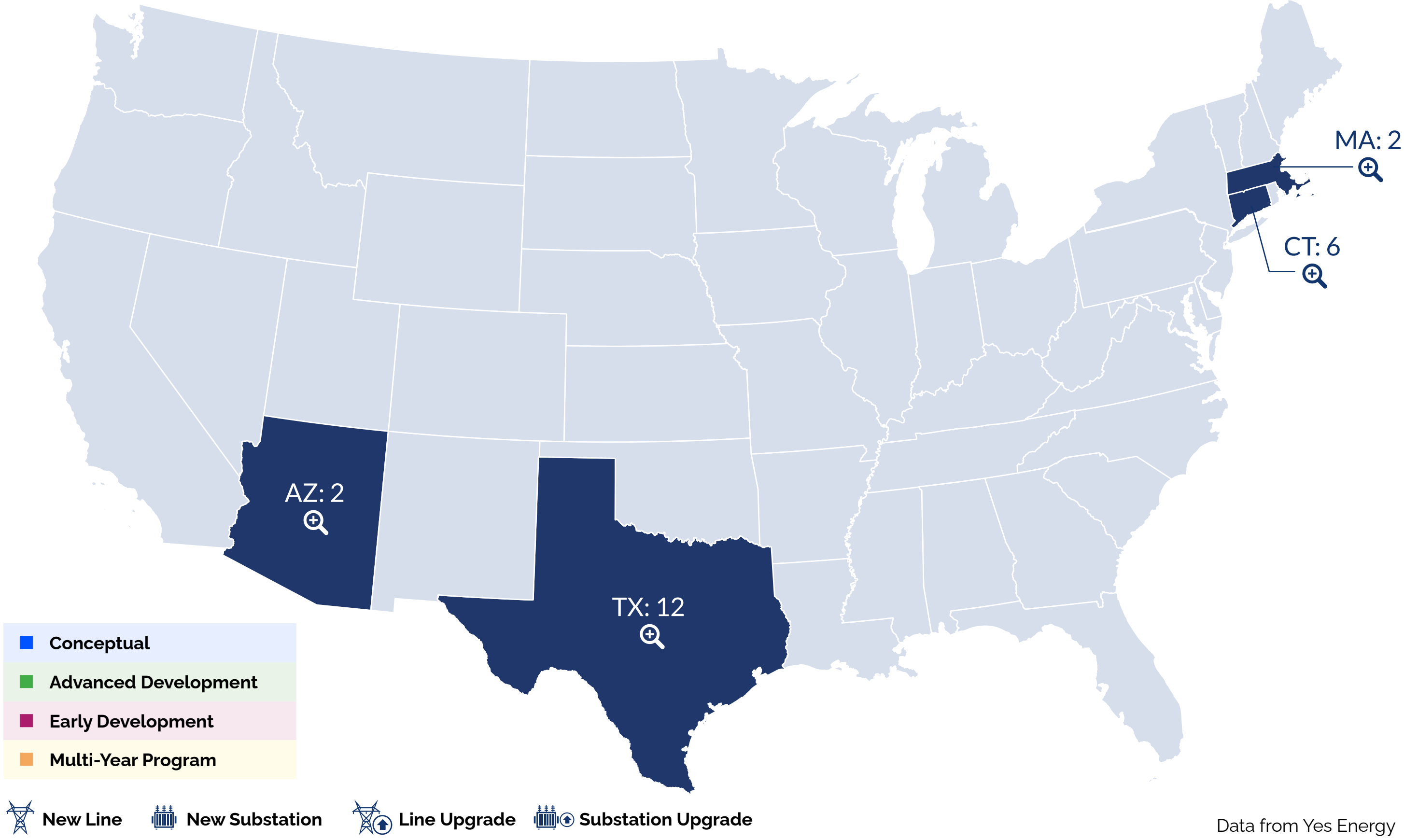
The REAL Team passed the measure, 8-6. There were five abstentions.

The DR policy's approval is contingent on a later endorsement for SPP's load-resource entity's peak demand assessment, which has drawn concerns in recent meetings. Staff is not asking for the assessment's endorsement in July. Assuming MOPC and board approval in October and November, staff intended to file both tariff revisions simultaneously at FERC.

"We're just moving the DR policy in a faster time frame than that of the LRE peak demand assessment," Henderson said.

"Here's a policy that we're moving forward without analysis of impacts, without a specific methodology, and we've done that without bringing it back to the group that has the closest awareness of all the data," Kennedy said, referring to the LRE assessment and the SAWG. "What staff has proposed here is shifting out the timeline so this MOPC working group really does have more time to understand what's being done with demand assessment." ■

T&D Projects Added in the Past Week



Data from Yes Energy

Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
Panda - Freedom 230 kV Line Upgrade	Pinnacle West	Arizona Public Service	230	2100	AZ / AZ
Cotton Transmission Corridor	Pinnacle West	Arizona Public Service	500	2100	AZ / AZ
Bloomfield Substation Upgrade and Expansion	Eversource Energy	Connecticut Light and Power	115	2027	CT
Berlin Substation Upgrade	Eversource Energy	Connecticut Light and Power	115	2027	CT
Stevenson Substation Upgrade	Eversource Energy	Connecticut Light and Power	115	2028	CT
Enfield Substation Upgrade	Eversource Energy	Connecticut Light and Power	115	2025	CT
Westside 115kV Substation Upgrade	Eversource Energy	Connecticut Light and Power	115	2029	CT
West Brookfield Substation Upgrade	Eversource Energy	Connecticut Light and Power	115	2027	CT
Hyannis Junction Substation Upgrade	Eversource Energy	NSTAR Electric	115	2026	MA
Midtown New Substation	Eversource Energy	WMECO	115	2039	MA
Carrollton Northwest Switch - Renner Switch Line Clearance Improvement	Sempra Energy	Oncor Electric Delivery	345	2025	TX
Lateral Hardening Program 2025 - 2027	AEP	AEP Texas	115	2027	TX
Distribution Feeder Hardening Program 2025 - 2027	AEP	AEP Texas	35	2027	TX
Distribution System Protection Modernization Program 2025 - 2028	Xcel Energy	Southwestern Public Service	35	2028	TX
Base Camp 345kV Switch Station Upgrade	Sempra Energy	Oncor Electric Delivery	345	2026	TX
Distribution Overhead Hardening Program 2025 - 2028	Xcel Energy	Southwestern Public Service	35	2028	TX
Argyle - Krum Tap Switch Line Upgrade	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX
Expanse - Estacado Line Upgrade	Sempra Energy	Oncor Electric Delivery	138	2026	TX / TX
Navarro Switch - Big Brown Switch Line Clearance Improvement	Sempra Energy	Oncor Electric Delivery	345	2030	TX / TX
Jacksboro Tap - Jacksboro Sinclair Line Upgrade	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX
Oates (GP&L) - Mesquite North Line Upgrade	Sempra Energy	Oncor Electric Delivery	138	2025	TX / TX
Oran Sub - Chico West Tap Switch Line Upgrade	Sempra Energy	Oncor Electric Delivery	69	2025	TX / TX

Company Briefs

Sierra Club Executive Director on Leave After Rocky Tenure

Ben Jealous, executive director of the Sierra Club, is on leave as of July 11, the organization confirmed, after less than three years leading the environmental nonprofit.

The organization's move comes after simmering tensions among local chapters and complaints from a group of managers as well as its union. Last month, a group of more than 100 employees sent a letter to the group's board of directors expressing concerns that Jealous was not prepared to shepherd the 132-year-old organization through a second Trump administration.

Loren Blackford will run the organization as interim executive director, according to the Sierra Club website.

More: *The New York Times*

Orsted Secures $3B Financing for Taiwan Wind Farm

Orsted said last week that it had secured more than $3 billion in project financing for the Greater Changhua 2 wind farm offshore Taiwan.

The Danish renewable energy company said it has reached financial close on a project-finance package with 25 banks and five export credit agencies to raise $3.08 billion for the 632-MW project.

Orsted is pushing ahead with the offshore project in Asia as renewables companies face increasingly onerous regulatory headwinds in the U.S. and higher interest rates in Europe.

More: *The Wall Street Journal*

MN8 Energy Bags $575M from Selling Senior Notes in U.S.

MN8 Energy, a spin off of Goldman Sachs Asset Management, has raised $575 million from an offering of senior secured notes to repay some of its debt and support its portfolio.

The notes are backed by a 972-MW portfolio of distributed generation and utility-scale photovoltaic solar projects and a 75-MW/four-hour battery energy storage system. The 29 projects are spread across nine states, MN8 said.

"This financing provides us with the flexibility we need to efficiently fund our robust pipeline as we continue scaling our business," MN8 CFO David Callen said.

More: *Renewables Now*

Federal Briefs

DOGE told NRC to 'Rubber Stamp' Nuclear Projects

A representative of the so-called Department of Government Efficiency (DOGE) told the chair and top staff of the Nuclear Regulatory Commission that the agency will be expected to give "rubber stamp" approval to new reactors tested by the departments of Energy or Defense, according to people present at a meeting in May.

The meeting was held after President Donald Trump signed an executive order May 23 to supplant the NRC's historical role as the sole agency responsible for ensuring commercial nuclear projects are safe and would not threaten public health. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

Under Trump's executive order, the NRC would not be able to revisit issues assessed by DOE or the Pentagon, but the people with knowledge of the meeting said the DOGE representative and DOE officials went a step further to suggest the NRC's secondary assessment should be a foregone conclusion.

More: *E&E News by POLITICO*

Pentagon to Become Largest Shareholder in MP Materials

The Defense Department will become the largest shareholder in rare earth miner MP Materials after agreeing to buy $400 million of its preferred stock, the company said last week.

MP owns the only operational rare earth mine in the U.S. at Mountain Pass, Calif., about 60 miles outside Las Vegas. Proceeds from the Pentagon investment will be used to expand MP's rare earths processing capacity and magnet production, the company said.

CEO James Litinsky described the Pentagon investment as a public-private partnership that will speed the buildout of an end-to-end rare earth magnet supply chain in the U.S. "I want to be very clear: This is not a nationalization," Litinsky told CNBC's "Squawk on the Street" last week.

More: *CNBC*

Rhodium: OBBBA Expected to Send Energy Prices Surging

As a result of the One Big Beautiful Bill Act, national average household energy prices are expected to rise by $78 to $192 by 2035, according to a *report* from Rhodium Group.

As much as half to two-thirds of the cost increases for households are expected to be driven by increased spending on fuel, including gas, diesel and electricity for electric vehicles, according to the report.

Rhodium attributes as much as one-quarter to half of the increase to rising electricity rates, which are expected to jump 2 to 4% by 2035.

More: *Inc.*

State Briefs

ALABAMA

Judge: PSC not Required to Hear from Public on Fuel Costs

A state judge has ruled that the Public Service Commission does not have to allow public input when deciding how much Alabama Power can charge customers for fuel costs.

Montgomery County Circuit Court Judge Brooke Reid denied an appeal from Energy Alabama to give public input in the commission's proceedings for Alabama Power's "Rate Energy Cost Recovery," the part of ratepayers' bills the utility uses to recoup fuel costs.

Energy Alabama had petitioned to be able to give public input in the PSC's Rate ECR docket, but the commission denied the group's request twice. Reid said Energy Alabama did not show that its rights had been violated by the commission's denial.

More: *AL.com*

GEORGIA

Tiny Turnout Likely for PSC Democratic Primary Runoff

State election officials are expecting low turnout today in the Democratic primary runoff election for the Public Service Commission's District 3, which covers Fulton, DeKalb and Clayton counties.

Only about 2.4% of the state's roughly 8.4 million registered voters cast ballots in Republican and Democratic primaries for seats on the PSC last month. Neither former Atlanta City Councilwoman Keisha Sean Waites nor clean energy advocate Peter Hubbard won a majority of the vote in the three-way Democratic primary for District 3.

The winner will challenge incumbent Republican Commissioner **Fitz Johnson**. Current PSC Vice Chair Tim Echols easily won the Republican primary in his bid for re-election in District 2.

More: *Rough Draft Atlanta*

MICHIGAN

PSC Approves Route of Helix-to-Hiple Transmission Line

The Public Service Commission last week approved the prime route through Branch and Calhoun counties for construction of a 55-mile, 345-kV transmission line despite objections from numerous residents.

The Helix-to-Hiple project, from Indiana to a substation near Duck Lake, is expected to be completed after 2028. MISO included the project in its long-range transmission plan. (See *MISO Picks Republic Transmission for 1st LRTP Competitive Project*.)

The commission found the proposed route reasonable over the alternate route because it resulted in fewer impacts on archaeological sites, reduced the number of residences within 500 feet of the line's right of way and decreased the number of parcels crossed by the line. Despite two years of notices and public meetings, several residents said they were unaware of the project until contractors requested that they sign easements.

More: *The Daily Reporter*

MONTANA

NorthWestern, PSC Dial Back Rate Hike

The Public Service Commission voted 3-2 earlier this month to approve a reduced rate increase for NorthWestern Energy than the one it had implemented in May after reaching a settlement with the state Consumer Counsel and about a dozen of its largest customers.

The rate NorthWestern incorporated in customers' bills in May, without regulators' approval, relied on a little-known, rarely used state law that allows a monopoly utility to adopt its proposed rate structure if the PSC hasn't acted on its rate hike request within nine months.

PSC President Brad Molnar, who voted against the proposed rates, suggested the utility may be using the rate decrease as a "communications tool" to shore up public opinion following the self-implemented increase. He argued that the more prudent course of action would be to ratchet rates back down to the interim rates the commission signed off in late November while the agency considers the mass of filings and late June expert testimony tied to a more permanent rate structure the utility is seeking.

More: *Montana Free Press*

PENNSYLVANIA

Trump to Announce $70B in AI, Energy Investments at Summit

President Donald Trump will announce $70 billion in artificial intelligence and energy investments for the state today at an event near Pittsburgh, according to a White House official and a person familiar with the initiatives.

Trump will appear at the inaugural Pennsylvania Energy and Innovation Summit, which aims to ignite "Pennsylvania's incredible potential to power the AI revolution," according to U.S. Sen. Dave McCormick (R).

More than 60 CEOs will attend the events, including ExxonMobil's Darren Woods, Chevron's Mike Wirth, BlackRock's Larry Fink, Palantir's Alex Karp, Anthropic's Dario Amodei and Amazon Web Services' Matt Garman.

More: *Axios*

UTAH

Rocky Mountain Power Appeals Hike Denial to Supreme Court

Rocky Mountain Power has appealed the Public Service Commission's rejection of its 18% rate hike to the state Supreme Court amid a war of words between the utility and the agency.

The utility initially proposed a 30% increase but lowered its request after public outcry. The PSC rejected the request, granting it only a 4.7% increase. RMP requested reconsideration, but the PSC denied this request as well, noting the utility's "hyperbolic, intemperate and occasionally disrespectful tone" in its filing and accusing it of flinging "baseless, sweeping accusations."

The issue has also invoked the wrath of state legislators, who have summoned utility executives to hearings and threatened to break up PacifiCorp.

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