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Rosner Voices Support for Large Load ANOPR

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States and consumer advocates have expressed concern that FERC exerting authority over large loads could infringe on state authority and, depending on how rules are designed, may lead to consumer cost pressures and challenges with forecasting load growth.

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FERC/FEDERAL

The White House / FTC

Supreme Court Justices Seem Skeptical on Agency Independence

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The case directly implicates the Federal Trade Commission, but its finding could overturn the independence of FERC and other regulatory agencies.

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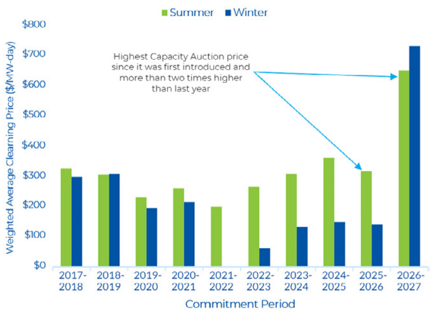

Power Advisory

Big Jump in Ontario Capacity Prices Signals Tightening Supplies

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Although rising capacity prices will have little impact on ratepayers, observers said the jump is further evidence of tightening supply/demand conditions in the Eastern Interconnection.

MISO

Ameren Missouri

MISO Declines Stakeholder Ask for Pause on 2025 Queue to Clear Backlog (p.36)

MISO has decided against taking a breather before it begins studies on its 2025 cycle of generator interconnection requests in early January 2026. Stakeholders asked MISO to consider a delay to focus on projects in the 2021, 2022 and 2023 cycles that aren't completed.

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In this week's issue

Clean Energy Must Start Post-Trump Planning Now

And it Needs to be Strategic, Outcome-oriented and Achievable in 4 Years

By K Kaufmann


K Kaufmann

I have been thinking a lot lately about how we do or don't plan for technological transitions, like the current clean energy transition now underway in the United States and worldwide.

In his closing remarks at the United Nations' climate conference known as COP30, Brazilian diplomat and conference president André Corrêa do Lago acknowledged the meeting's failure, once again, to keep even a mention of a phaseout of fossil fuels in the final statement from the event. He pledged instead to begin work on a road map for a "just, orderly and equitable" transition away from fossil fuels and pointed to plans for an *international conference* focused entirely on such a phaseout, planned for April 28-29, 2026, in Colombia.

That such a conference is being planned is historic in and of itself, though how successful it will be remains an open question, given the ongoing influence of fossil fuel industry lobbyists at climate conferences. More than 1,600 fossil fuel lobbyists took part in COP30 in Belem, Brazil — one in every 25 attendees — according to a *report* from the nonprofit Kick Big Polluters Out.

But lobbyists are more a symptom than a cause. The real problem lies in the idea that we can in some just, orderly and equitable way plan for a transition away from fossil fuels. Technological transitions are by their very nature unplanned, disorderly and inevitably unjust.

One need look no further than the lightning speed with which artificial intelligence has become the dominant digital technology worldwide, permeating almost every aspect of our economic, social and political lives and throwing the U.S. electric power industry into a chaotic panic.

And, as in all technological transitions, winners, losers and collateral damage are inevitable.

The narrative from the Trump administration, some regulators and utility industry leaders is that to win the global race for AI leadership, we must keep existing coal and natural gas plants online and build even more to power the hyperscale data centers now springing up across the across the country.

Climate action is the big loser here. Rising greenhouse gas emissions and the increasingly catastrophic extreme weather events and other environmental upheavals they cause have been downgraded, in the words of Energy Secretary Chris Wright, to mere side effects of our digital society.

The collateral damage: developing nations and remote, rural communities — including those in the United States — that are most exposed and vulnerable to extreme weather.

Which is not to say we should not plan but rather refocus on things that can be planned for, things we can control.

Why This Matters

The transition increasingly is being driven by the combined forces of economics and technology; clean technologies are frequently just better, more efficient and affordable. In his heart of hearts, even Chris Wright must know that renewables — solar, wind, storage and other clean technologies — are the future, says columnist K Kaufmann.

Biden's Implementation Blues

Lack of planning was a core problem in the Biden administration's seeming inability to implement — at speed and scale — the clean energy programs authorized by the Infrastructure Investment and Jobs Act and the Inflation Reduction Act.

"Three years after the first of those laws passed, only a handful of federally funded projects had broken ground," says a recent *report* from three former staffers at Biden's Department of Energy — Ramsey Fahs, Alan Propp and Louise White. "This meant the political theory animating the administration's approach — that the economic development generated by clean energy projects and industries would create a durable bipartisan coalition — was never truly tested."

It also meant that President Donald Trump was able to quickly roll back programs and claw back funding, leading to a massive private sector retreat from previously announced multimillion-dollar projects.

"Years of work were undone in just a few months," the report says, with at least 32 projects totaling $22 billion in investments canceled in the first six months of 2025.

Based on interviews with more than 80 DOE staffers, the report's list of implementation blockers includes an absence of "clean, sector-specific deployment targets" and a reliance on "obligation metrics" — that is, money that was officially awarded but not actually spent — which resulted in a "false sense of progress."

Other challenges included tangled decision-making processes and an overly cautious approach to risk management, resulting in long and complicated application and award processes.

Funded with $5 billion from the IIJA, the National Electric Vehicle Infrastructure program is a case in point. NEVI was aimed at installing DC fast EV chargers along major highways in every state, and when it was rolled out in February of 2022, the administration hoped to have the first chargers in operation by the end of the year. Hobbled by a range of federal, state and local requirements, the first NEVI station was opened in Ohio in December 2023.

Following Trump's unsuccessful efforts to roll back NEVI, the most recent *count* has about 133 federally funded stations open in 16 states. Revised guidelines from

Secretary of Transportation Sean Duffy have removed or minimized certain NEVI requirements, like ensuring that NEVI chargers benefit low-income communities.

What Fahs, Propp and White propose is that Democrats take a page from the Heritage Foundation's *Project 2025*, the massive manifesto setting out plans for a second Trump administration, published in April 2023, and immediately start planning clean energy policies and programs, and recruiting staff for a future Democratic administration.

"Any attempt by the federal government to play an important role in advancing industrial and clean energy development across the United States will require a great deal more thoughtfulness and detail than even Project 2025 achieved," the report says.

Essential parts of such a plan — let's not call it Project 2029 — should include setting goals for "specific sectoral outcomes," with strategies "designed to be actionable in a single term." An administrative culture that promotes speed, decision-making and accountability for meeting goals and timelines will also be critical, as will more streamlined and flexible contracting practices, the report says.

For example, Build America, Buy America policies that require "lawyers to certify every bolt" of a project is domestically produced should be replaced with an approach that focuses on "a few high-impact sectors and provide[s] waivers or exemptions for low-value components and equipment with no domestic supply chain yet."

The report also calls for more public-private partnerships, such as Trump's recent deal with rare-earths supplier MP Materials, which "combined an equity stake, loans, warrants and a 10-year price floor and offtake agreement … [showing] how a sufficiently motivated executive branch can comprehensively derisk deployment in a key sector."

(Certainly, under former Energy Secretary Jennifer Granholm, DOE pursued similar derisking partnerships, if not as blatantly commercial or raising concerns about conflicts of interest as Trump's deals.)

The Need to be Feared

The other side of this conversation centers on how states and the clean energy industry itself are or aren't planning for the dramatic swings in federal energy policy they now face — specifically the loss of federal tax credits, grants and other incentives and Trump's ongoing war against renewables.

At the recent Solar Focus conference in Arlington, Va., sponsored by the Chesapeake Solar and Storage Association, known as CHESSA, Jigar Shah, former director of DOE's Loan Programs Office, also called for a major cultural shift in the clean energy industry.

Too many businesses "are planning for the days that look like last year, and I think it's important for us to recognize that those days are gone, and they're never coming back, like even after the Trump administration leaves office," he said.

Now leading a clean tech consulting firm, Multiplier, Shah delivered a typically provocative call to action. "Why do we have rules in place that make it impossible for us to integrate with electric utilities? … It's not enough to be liked; you really need to be feared," he said. "When people don't deliver for us, they should lose their seats. …

"One of the biggest challenges that we have in this moment is that … there's still a feeling that our industry doesn't work unless it's mandated, that people have to use us," he said. Rather, with new Democratic governors in New Jersey and Virginia, the industry should be coming at them with clear, outcome-focused plans, for example, to build utility-scale batteries in key locations to improve system reliability, while reducing consumer electric bills by 20%.

"If we only achieve 80% of that stuff two years later, no one's going to vilify us for that," he said.

Speaking on the same panel, Sachu Constantine, executive director of the advocacy group Vote Solar, laid out what has become the industry's standard argument for renewables as a vital solution to the growth in demand for electric power, driven by data centers, electrification and industrialization.

"We are the lowest-cost, fastest, market-scalable energy source out there," he said.

But Constantine also said states should be seen as a testing ground for the new policies and regulatory structures needed to set goals and ensure outcomes that respond to that growth. "We shouldn't be afraid of that. This is a chance, a generational chance, to create the regulatory scheme we want. We should look to the states and what they're trying and what's successful as a blueprint for what the future looks like," he said.

Integrating and assigning value to solar, storage and other distributed resources

COP30 President André Corrêa do Lago at the conference's closing session in Belem, Brazil, on Nov. 22. | *UN Climate Change - Kiara Worth*

as assets for capacity markets should be a top priority, he said.

Nicole Steele, another former DOE and EPA staffer, is now director of climate policy at Amalgamated Bank, a commercial bank that devotes 40% of its lending to climate solutions.

Like Shah and Constantine, she is similarly focused on outcomes, often at the local level, in a post-subsidy world where projects must be able to access market-rate capital. At EPA, she worked on the Greenhouse Gas Reduction Fund, which was intended, in part, to help fund state-level green banks.

With that funding still frozen by EPA, "there's a whole shift coming together that really is looking at revenue bonds [for] supporting green banks," Steele said. "We're throwing our weight behind some of that work to really make sure that green banks are not only structurally playing a role — to not just be a lender, but to be the lender that can seed private sector capital and drive down the cost of that capital or make that capital more accessible."

Why 1,600 Lobbyists?

So, is a just, orderly and equitable transition away from fossil fuels possible? I would never say never, but based on the analysis and insights of those who worked so hard for it during the Biden administration, what may be more likely and effective is a strategically planned and outcome-focused transition toward clean energy.

In other words, we need a plan with targets we can achieve within four years and then ensure we have the financial and administrative infrastructure to do just that.

Wright's recent DOE reorganization — killing the Office of Clean Energy Demonstrations, the Office of Energy Efficiency and Renewable Energy, and the Grid Deployment Office — continues his efforts to wipe any mention of renewable energy from the national consciousness. The National Renewable Energy Laboratory has been renamed the National Laboratory of the Rockies.

But even Wright must know, in his heart of hearts, that solar, wind, storage and other clean technologies are the future. In the first half of 2025, renewables accounted for 91% of new power on the U.S. grid. During the same time period, new solar and wind (403 TWh) more than covered new electric power demand around the world (369 TWh), according to U.K. industry analyst *Ember*.

The International Energy Agency expects renewable capacity worldwide will *double*, to 4,600 GW, by 2030 — still short of the international pledge at COP28 to triple renewable power over 2022 levels by 2030, but impressive.

The transition increasingly is being driven by the combined forces of economics and technology; clean technologies are frequently just better, more efficient and affordable.

Rising electric bills were a critical issue in off-year election wins for Democratic Governors-elect Abigail Spanberger in Virginia and Mikie Sherrill in New Jersey — one that could drive more Democratic victories in the 2026 midterms. Both residential and commercial solar and storage provide one of the quickest ways to cut bills, with very small-scale, plug-in (and largely unregulated) "balcony" solar and storage systems gaining in popularity.

With more renewables on the grid, Americans may see that we don't need new fossil-fueled generation and can retire existing plants, without threatening reliability or affordability.

The fossil fuel industry will bring all its power, money and influence to slow the transition — as it has, at least temporarily, in the U.S. But perhaps why the industry needed those 1,600 lobbyists at COP30 was fear and a dawning recognition that it will eventually become irrelevant. ■

— Livewire columnist K Kaufmann has been writing about clean energy for 20 years. She now writes the E/lectrify newsletter.

Analysis Offers Blueprint for Faster Data Center Interconnection

Benefits of Load Flexibility, Bring-your-own Capacity Modeled at 6 PJM Sites

By John Cropley

A new analysis models a markedly faster interconnection process for large data centers where the developer and utility can agree on flexible interconnection and the developer can secure some of its own generation capacity.

Camus Energy, encoord and Princeton University's ZERO Lab analyzed six hypothetical data centers' large load requests at locations within PJM that have been the scene of actual requests.

The analysis concluded that by agreeing to partial curtailment during limited periods of system stress, and by directly procuring accredited generation capacity, data center developers could reach operational status in roughly two years instead of five to seven years. It also found the approach would shield other grid customers from most of the costs.

It is, Camus said, the first publicly available study to combine real utility transmission system data, system-level capacity expansion modeling and site-level capacity optimization to evaluate how flexibility can accelerate data center interconnections.

And it provides a repeatable blueprint other utilities can follow, Camus said.

Different Approach

Load flexibility is a concept that is drawing attention as the rate of large load requests exceeds the pace at which the grid can be expanded to serve them.

A Duke University study in early 2025 concluded the existing U.S. power network could handle 126 GW of new demand with no new generation if data centers cut their energy use by as little as 1% in times of peak demand. (See US Grid Has Flexible 'Headroom' for Data Center Demand Growth.)

Some of the biggest names in the tech sector have begun exploring demand response as a way to limit exposure to the high cost and slow pace of building new infrastructure to serve these new large loads. (See Google Strikes Demand Response Deals with I&M, TVA.)

Why This Matters

The analysis presents models for flexibility that could shave time and money off the interconnection process.

Construction is ready to begin on a third data center at the Google complex in Storey County, Nev. | *Google*

The new study — "Flexible Data Centers: A Faster, More Affordable Path to Power" — was funded by Google, which reviewed it prior to publication.

It advocates for a mixed, flexible approach.

The sticking point, Camus CEO Astrid Atkinson told *RTO Insider*, is that most tariffs have no middle ground — large-load customers can build their own generation behind the meter or they can get firm service from a utility, but not some mixture of both.

To change this, utilities need to have not only the willingness but the skills and technology to consider alternatives, she said.

Data center operators, too, need to open up to the idea.

"They've also been very reluctant to consider curtailment," Atkinson said. "Historically, they want to make sure that if they're building a data center facility, that they can use 100% of the power footprint that the facility is designed for. … Being paid to curtail is absolutely dwarfed by the opportunity cost of not using the resource that they've invested in."

The "huge disconnect" between the time frames on which Big Tech and the U.S. power industry operate is leading to changes, she said, because there is plenty of room on the grid for what is described variously as conditional firm service, non-firm service or flexible connections.

The obligation-to-serve model "naturally means that the system, for the most part, does have a decent amount of slack capacity in many places, most of the time," Atkinson said.

Some utilities are receptive to the idea, she added.

"There's obviously a lot of complexity in how that plays out, but we have definitely seen utilities be actively curious and willing to explore flexible interconnection models for data centers and other large load assets.

"There's also challenges in terms of, we need to adapt the existing market participation rules and the regulatory models that support connecting stuff to the grid."

Updated interconnection methodologies and new market mechanisms are among the potential changes, Atkinson said. But these are relatively new concepts for an industry that typically makes changes at a deliberate pace.

"This whole conversation, I think in some ways, was kicked off by the Duke University report at the beginning of the year. And it's really just this year that data centers have been interested in and willing to explore this sort of model. So the conversation is relatively young."

The Analysis

The analysis applied system-, utility- and site-level modeling to the six scenarios it created.

Importantly, the study looked at all 8,760 hours of the year, not just at the worst moments of the year.

It found that a 500-MW data center using flexible grid connection and bringing its own capacity to the table could lop three to five years off its grid connection process.

It found grid power was available for more than 99% of all hours in a year; on-site resources such as batteries, generators and load flex were dispatched 40 to 70 hours a year; transmission curtailment lasting four to 16 hours totaled seven to 35 hours a year; and generation shortfalls totaled 32 hours a year, mostly due to extreme weather.

And it found that while each gigawatt of new data center demand creates $764 million in supply system costs under a traditional firm-only interconnection, a non-firm interconnection could insulate the grid from almost all of that cost: Flexible interconnections with 20% conditional firm would avoid 273 MW of new build at a cost of $78 million per gigawatt; internalizing capacity would internalize $326 million in capacity costs per gigawatt; and the data centers' bill payments would cover $329 million per gigawatt.

The research evaluated dynamic line rating (DLR) as a complementary option and found it boosted transmission capacity during most hours and significantly reduced the need for curtailment at the modeled data centers. While DLR is beyond the reach of data centers, they could partner with utilities to expand its use, the authors write.

The Conclusion

The report identifies four key barriers to implementing the flexible connection model it explores:

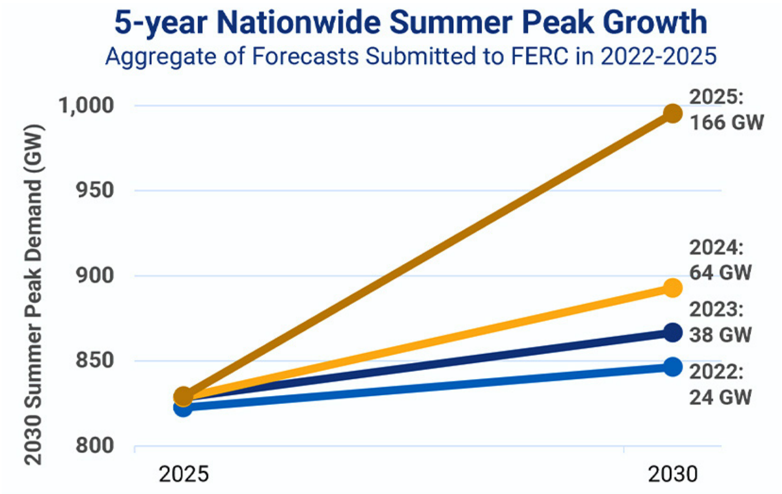
- Planning frameworks assume every load always is at its maximum; regulators instead would need to incorporate limited large-load flexibility where voluntarily offered as an explicit input in integrated resource planning and resource adequacy processes.
- Accreditation methods do not consistently define and value load-modifying resources; regulators would need to extend accreditation to recognize the reliability contribution of emergency load-modifying resources in resource adequacy planning under predetermined bounds of duration and annual availability.
- Tariffs allow only firm and non-firm service, and often not even non-firm service; FERC and state regulators should encourage transmission providers to change their processes to better use voluntary flexible loads.
- Transmission and resource adequacy commitments would need to be recognized as independent of each other; FERC or other regulators could clarify this through rulemaking or guidance.

The report follows the list with an optimistic note: "Although regulatory frameworks are still evolving, momentum is building across federal, regional, and state levels."

The authors add the caveat that the analysis is a demonstration of the methodology on certain sites and system configurations, not a comprehensive national assessment. ■

Grid Strategies: Pace of Load Growth Continues to Speed up

By James Downing



Grid Strategies

The power industry's demand forecasts expect national summer peak to swell by 166 GW by 2030, which would be the equivalent of adding 15 times the peak load of New York City, Grid Strategies said in its latest load growth *report*.

The estimates, which are based on reports submitted to FERC through Form 714, include 90 GW of new data centers, 30 GW of industrial growth, 10 GW from oil and gas and mining, and 30 GW from other sources. This is the third report in a row published by Grid Strategies showing demand growth, and the pace has grown each time, the firm's president, Rob Gramlich, said during a webinar hosted by Americans for a Clean Energy Grid on Dec. 4.

"We're talking about over 5% annual growth, which is pretty extraordinary," Gramlich said. "Now it's not, by historical standards, a growth rate that is unprecedented."

It certainly is in total gigawatts, however, as the last time the electric industry saw growth at similar levels in the middle of the 20th century, it was from a smaller base, he noted.

"We've been able to meet the pace of growth in the past," Gramlich said. "But of course, we've, in a way, as an industry and a regulatory community, lost our muscle memory on a lot of these things. It's just not something that most of us in our careers have had to deal with."

Energy use is growing even faster than the peak numbers, at 50% over the next half decade, which means the new demand has a higher load factor, he added. The bulk power system in the U.S. averages a 60% load factor today, but that is expected to reach 66% by 2030 as new demand comes online, the report says.

"Data centers generally operate at an above-average load factor," the report said. "For example, Dominion Virginia reported an 82% load factor for large data centers in 2024, and Duke Energy states that it plans for new large loads to have an 80% load factor. It appears that some large load forecasts may use higher values, perhaps as high as 100%, which is unrealistic."

The utility reports to FERC are likely overstating the amount of data center load, with an estimate from Cleanview showing just 60 GW by 2029, and TD Cowen predicting 65 GW by 2030 based on orders for advanced microchips.

"Somewhat similar to what we have on the generation side, there are always way more proposed projects than there are actual projects that go forward," Gramlich said. "I never liked the term 'speculative' about generation. I don't really like it about load either. It's just how the business works. If you're building anything, you have to not put all your eggs in one site basket."

All the new load being projected means that the industry and regulators are going to need to expand the BPS, Virginia State Corporation Commission Judge Kelsey Bagot said on the webinar.

"We're certainly going to have to build a lot of generation right, which necessarily includes the transmission component," she added.

Generally, the industry has been reactive but meeting the needs of these new customers while keeping costs affordable will require it to be more proactive in its planning, Bagot said. The cost of the expansion naturally leads to questions about allocation, which can lead to litigation at the state level and goes to the core of concerns that existing ratepayers have about affordability.

"In order to be comfortable proactively building, I think we need to pay attention to cost allocation, and at the state level, that means making sure that we are allocating transmission build to the folks that are driving the need for the build, right?" Bagot said. "That will get the end-use customer more comfortable with the amount of transmission that we're building."

Getting the expansion done affordably means using all the tools available, including advanced transmission technologies, distributed energy resources and virtual power plants, said Sarah Freeman, a principal at the Regulatory Assistance Project.

"It's so critical that we encourage/force our utilities to take these bigger picture looks," Freeman said.

Amazon Web Services Energy Policy Manager Ray Fakhoury agreed that the industry needs to proactively plan to meet new loads more than it has recently, and he said the new technologies his company and others are working on — those that are driving the growth — can help.

"There is a way to integrate artificial intelligence, machine learning [and] the highest standards of all of these software programming so that we can identify the optimal spots to build out transmission," he argued. ■

Supreme Court Justices Seem Skeptical on Agency Independence

By James Downing

The Supreme Court appeared ready to overturn a precedent that has maintained the independence of regulatory agencies like FERC for the past 90 years.

Justices heard oral arguments in *Trump v. Slaughter*, a case that springs from President Donald Trump firing Federal Trade Commissioner Rebecca Slaughter earlier in 2025. Commissioners at the FTC, FERC and other agencies enjoy "for cause" firing protections under *Humphrey's Executor*, which a recent amicus brief argued has ensured agency independence. (See *Former FERC Commissioners Ask Supreme Court to Preserve Agency Independence*.)

Multiple justices appointed by Republicans questioned Amit Agarwal, the special counsel for Protect Democracy who argued for Slaughter, on why Congress could not just expand multimember commissions to take over the work of EPA or the Commerce Department, thus insulating them from presidential oversight.

Some executive agencies, including the State Department and the Department of Defense, are pre-empted from that entirely under the Constitution because they are wielding the president's "conclusive and preclusive constitutional authorities," Agarwal said.

Chief Justice John Roberts asked whether Congress could reorganize the Department of Veterans Affairs, or the Department of Education, so that they are run by a commission with officers that could only be removed for a cause.

"Yeah, I think that it is probably within the realm of possibility for agencies, yes, Chief Justice Roberts," Agarwal said. "And the constraint historically has been that these types of determinations have been made through a process of political accommodation between Congress and the president."


President Donald Trump and Rebecca Kelly Slaughter | *The White House / FTC*

Why This Matters

The case directly implicates the Federal Trade Commission, but its finding could overturn the independence of FERC and other regulatory agencies.

Justice Elena Kagan argued that the bigger risk would not be Congress usurping executive authority with new bipartisan commissions, but that if the Trump administration wins, then the Education Department will still be authorized by Congress but without any employees.

"I think you're absolutely right, Justice Kagan, that there are competing dangers here, and it makes a whole lot of sense to us to weigh the real-world dangers that we know are a virtual certainty that would result from adopting petitioners' constitutional theory," Agarwal said.

He then added that Congress has never tried to convert an executive agency, as Roberts and several other justices postulated it could, but Justice Amy Coney Barrett said that does not prevent that from happening in the future.

In *Humphrey's Executor*, the court recognized that such agencies exercise legislative and judicial powers while still engaging in some executive function, but that does not make it an executive agency, Justice Ketanji Brown Jackson said.

Many agencies have been involved in civil enforcement cases, and the Supreme Court has never found any of them were therefore ineligible to have principal officers covered by for-cause protection, Agarwal said.

"You are just saying that the way the law has been interpreted by the court here, the existence of *Humphrey's* and Congress' reliance on these kinds of multimember agencies for something like 90 years plus, that's the background rule," Jackson said. "And so now it's up to the government and the solicitor general to come in to suggest that there's a constitutional problem with that."

The FTC Act is 111 years old, and *Humphrey's* has been case law since 1935, Agarwal noted, and he argued that similar setups go back to the earliest days of the U.S.

Justice Brett Kavanaugh asked whether it would be appropriate to give FTC commissioners or others with protections under *Humphrey's Executor* terms of up to 20 years. Agarwal argued that would be prevented by the Take Care Clause in Article II, Section 3 of the Constitution, as commissioners' time in office would span multiple presidencies.

"We don't dispute that the activities of these agencies are operating within the purview of the executive branch and they should be subject to constitutionally appropriate presidential supervision," Agarwal said.

Most of the regulators at issue in the case allow the president to pick a chair from among Senate-approved members for any reason, and Kavanaugh asked if that was required. Agarwal said it was not constitutionally required because when *Humphrey's Executor* was decided, the chair of the FTC was not removable, though the law changed 15 years later.

"I think putting those three together, your position would allow Congress to create independent agencies, maybe converting some of the existing executive agencies into independent agencies with no political balance requirement, with a long term, say, 10 or more years, and with the chairs not subject to removal as chair," Kavanaugh said. "So, you can imagine a situation — and I just want to give you a chance to deal with the hard hypothetical — when both houses of Congress and [the] president are controlled by the same party [and they create] a lot of these independent agencies or extending some of the current independent agencies … so as to thwart future presidents of the opposite party."

That would be constitutionally untenable because the president needs the authority to enact the law, Agarwal said. He cited *Seila Law v. CFPB*, in which the court found that the Consumer Financial Protection Bureau, which was run by one executive director, was not covered by *Humphrey's Executor*, but the FTC, with its staggered seven-year terms and removeable chair, is on the right side of the line.

"If it is really true that these kinds of for-cause removal protections, which after all authorize the president to fire commissioners just for good cause, if they really pose this fundamental threat to the Republic, petitioners could take their argument across the street and Congress could solve the problem tomorrow," Agarwal said. "They're not willing to do that."

The Federal Reserve Board of Governors benefits from the same protections as the FTC and FERC, but in a decision earlier in 2025 overruling the stay a lower court had placed on Trump's firing of National Labor Review Board (NLRB) and Merit Systems Protection Board (MSPB) members, the Supreme Court indicated its own separate legislative history.

Kavanaugh asked Solicitor General D. John Sauer about whether the effort to bring other regulatory agencies under greater presidential control would undermine the central bank's independence.

"We recognize and acknowledge what this court said in the [*Trump v. Wilcox*] stay opinion, which is that the Federal Reserve is a quasi-private, uniquely structured entity that follows a distinct historical tradition of the First and Second Banks of the United States," Sauer said.

Any issues of removal restrictions from the Federal Reserve would raise their own unique distinct issues, he added.

Justice Kagan then asked, based on the arguments that all executive power is vested in the president, what would stop the courts from expanding the decision to cover even the civil service.

"Employees are wielding executive power all over the place, and yet we've had civil service laws that give them substantial protection from removal for over a century," Kagan said. "How about those?"

Sauer said the case was not challenging the structure of the civil service, and the court has made clear in past decisions that its impacts are limited to the issues at hand.

"Logic has consequences," Kagan said. "Once you use a particular kind of argument to justify one thing, you can't turn your back on that kind of argument if it also justifies another thing in the exact same way. Putting a footnote in an opinion saying, 'We don't decide X, Y and Z because it's not before us,' doesn't do much good if the entire logic of the opinion drives you there."

D.C. Circuit Weighs in

Just days before the Supreme Court heard oral arguments in the Slaughter case, the D.C. Circuit of Appeals issued a *decision* in the case involving fired members of the NLRB and MSPB.

The court sided with Trump in the firings, but without overturning *Humphrey's Executor*.

"Congress may not restrict the president's ability to remove principal officers who wield substantial executive power," the two-judge majority said. "As explained below, the NLRB and MSPB wield substantial powers that are both executive in nature and different from the powers that *Humphrey's Executor* deemed to be merely quasi-legislative or quasi-judicial."

The majority noted that after *Humphrey's Executor*, other decisions had erased the distinction about "quasi-legislative" and "quasi-judicial," while others found that only three kinds of constitutional power exist and only executive power can be delegated.

"These considerations suggest that very little remains of *Humphrey's Executor*," the circuit court said.

Judge Florence Pan filed a dissent to the decision, saying some agencies' independence benefits the public and the multimember commissions at issue in *Humphrey's Executor* have been around for 138 years.

"For at least 90 years, it has been settled law that Congress may impose statutory for-cause removal protections in the exercise of its authority to organize and structure the executive branch," Pan wrote. "But today, my colleagues make us the first court to strike down the independence of a traditional multimember expert agency: They hold that the for-cause removal protections that safeguard the political independence of the National Labor Relations Board and the Merit Systems Protection Board are unconstitutional." ■

U.S. Solicitor General Sides Against Duke Energy in Antitrust Case

By James Downing

The Supreme Court should reject an appeal from Duke Energy of an antitrust case it lost in lower courts, the Office of the Solicitor General said in a brief filed Dec. 1 (*24-917*).

The 4th U.S. Circuit Court of Appeals found in August 2024 that Duke's alleged anticompetitive conduct against NTE Energy — an independent power producer serving municipal customers in North Carolina — warranted another look in a lower court, which sided with the other parties. Duke filed a petition for review at the Supreme Court in February. (See *4th Circuit Remands Duke Energy Market Power Lawsuit Filed by NTE*.)

"This appeal arises out of a campaign by an established monopolist to stop a more efficient rival from disturbing its long-dominant hold over a regional energy market," OSG said.

The beneficiary of a government grant of a monopoly more than a century ago, Duke has controlled the wholesale power market in the Carolinas for decades. Barriers to entry — including the high cost of power plants and the paucity of anchor clients big enough to help finance a competitor's generator — have helped it keep that monopoly.

"By dissuading such customers from switching to a potential competitor, an entrenched monopolist can prevent new entrants from gaining a foothold in the region — without creating a better product, producing a better service or implementing a general price cut," OSG said. "The summary-judgment record would support a finding that that is exactly what happened here."

Duke's old power plants were not competitive with NTE's, which used newer technology to produce electricity at a cheaper rate, so when the IPP tried to build one in in the Carolinas, Duke targeted the competition itself, OSG argued.

Why This Matters

The matters of antitrust law at issue in the case could have ramifications on other cases around the country.

"Petitioner recognized that this new plant would be viable only if respondent could sell power to the city of Fayetteville, the one sizable customer in the area whose contract was coming due," OSG said. "Petitioner therefore took a variety of steps intended to deter Fayetteville from switching to a new supplier."

Duke has not sought review of the underlying facts of the case, in which the 4th Circuit found that the various acts it took added up to what a jury could find to be an anticompetitive campaign, OSG noted.

"When a monopolist engages in a coordinated campaign to squelch competition, no circuit holds that each discrete aspect of the defendant's conduct must be analyzed in isolation," OSG said. "Instead, courts uniformly agree, consistent with this court's precedent, that a holistic analysis is appropriate in circumstances like these. The petition for a writ of *certiorari* should be denied."

Duke's petition for the Supreme Court to review the case argues that, on their own, none of its actions were illegal, saying the 4th Circuit effectively found that "0+0=1."

"The district court found that antitrust math is no different from ordinary arithmetic. If an antitrust plaintiff pleads a series of independently lawful acts, each of which does not violate this court's precedents, those acts cannot together add up to some nebulous antitrust violation," Duke said in its petition. "The Court of Appeals concluded otherwise, embracing a 'monopoly broth' theory prominent in the 1960s to 1980s but long since discarded."

The Supreme Court needs to intervene to restore antitrust law to the principles that have governed in more recent decades, the company argued. It overhauled how to prove monopolization under the Sherman Act starting in the 1990s.

U.S. Supreme Court | *Shutterstock*

"It replaced open-ended standards and generalized questions of anticompetitive intent with clear rules for particular categories of conduct," Duke said. "That doctrinal shift has provided much needed certainty for businesses and judges alike and has prevented antitrust law from chilling vigorous competition in the marketplace. Antitrust plaintiffs have long resisted that shift."

The U.S. Chamber of Commerce, the NC Chamber Legal Institute and the Business Roundtable filed an *amicus* brief taking Duke's side.

"In just a few short months, the decision below has already been cited dozens of times in briefs and decisions across the country as plaintiffs urge lower courts to disregard this court's discrete doctrinal standards in favor of 'holistic' analyses," they said.

Allowing the 4th Circuit's finding to stand would supercharge that trend with antitrust plaintiffs filing allegations of "complex" anticompetitive schemes that cannot satisfy the court's clear tests and would thus be "dead on arrival" in other circuits, they added. ■

Energy Industry Asks Congress to Authorize Cyber Defense Programs

By James Downing

Electricity sector participants urged Congress to back cyber security programs as the House Committee on Energy and Commerce's Subcommittee on Energy heard testimony on the efforts of nation-states and other actors to hack the bulk power system.

The Electricity Information Sharing and Analysis Center (E-ISAC) is the industry's clearinghouse for information on cyber and physical threats that works with government and other sectors to reduce security risks, NERC Senior Vice President and E-ISAC CEO Michael Ball said at the Dec. 2 hearing.

"The threat landscape is complex," Ball said. "It includes continuously evolving threats from sophisticated and very capable adversaries; among the most advanced are nation-states … which are very well-funded."

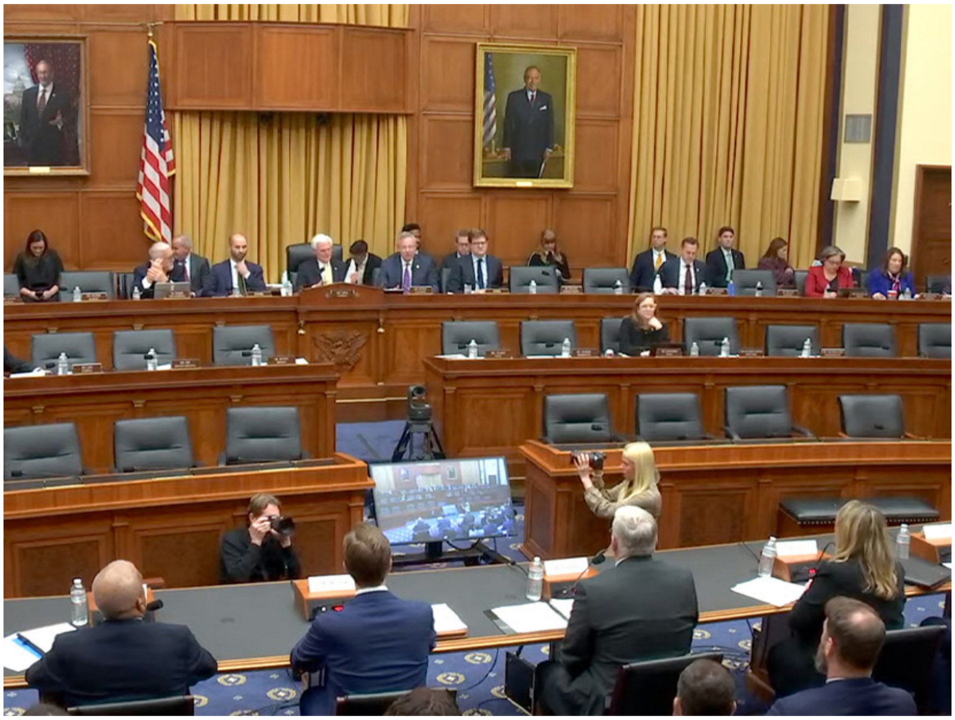
Ball said "numerous public reports underscore how these adversaries focus on the electric sector" and cited China, Russia, Iran and North Korea as being "monitored closely."

Chinese cyber threats have dominated risks to North America recently, as Russia and Iran are more focused on conflicts in their regions, Ball said in his written testimony. He said Salt Typhoon and other hacking groups to which attacks have been attributed are believed to be operated by China's Ministry of State Security. Ball's written testimony lists cyber attacks against other sectors, but that is no comfort for E-ISAC, he noted.

"The technologies targeted by Salt Typhoon are prolific across critical infrastructure sectors, including the electric sector, which makes repurposing tactics, techniques and procedures learned targeting one sector easier when targeting the next," Ball said.

Why This Matters

Programs that have helped the power industry get government intelligence on cyber threats could benefit from congressional action, experts said at a House hearing.



The House Energy and Commerce Committee's Subcommittee on Energy on Energy holds a hearing on the physical and cybersecurity of the grid. | *House Energy and Commerce Committee*

The rise in electricity demand most often linked to data center growth also offers new risks as Salt Typhoon targets those facilities. A NERC report from early 2025 highlights the risks sudden outages of large loads can pose to the grid, Ball said. (See *Data Centers' Reliability Impacts Examined at FERC Meeting*.)

Just the fact that load growth is cutting into reserve margins increases the risk of any kind of event on the grid, including cyber and physical attacks, said Kenergy CEO Tim Lindahl, who was testifying on behalf of the National Rural Electric Cooperative Association.

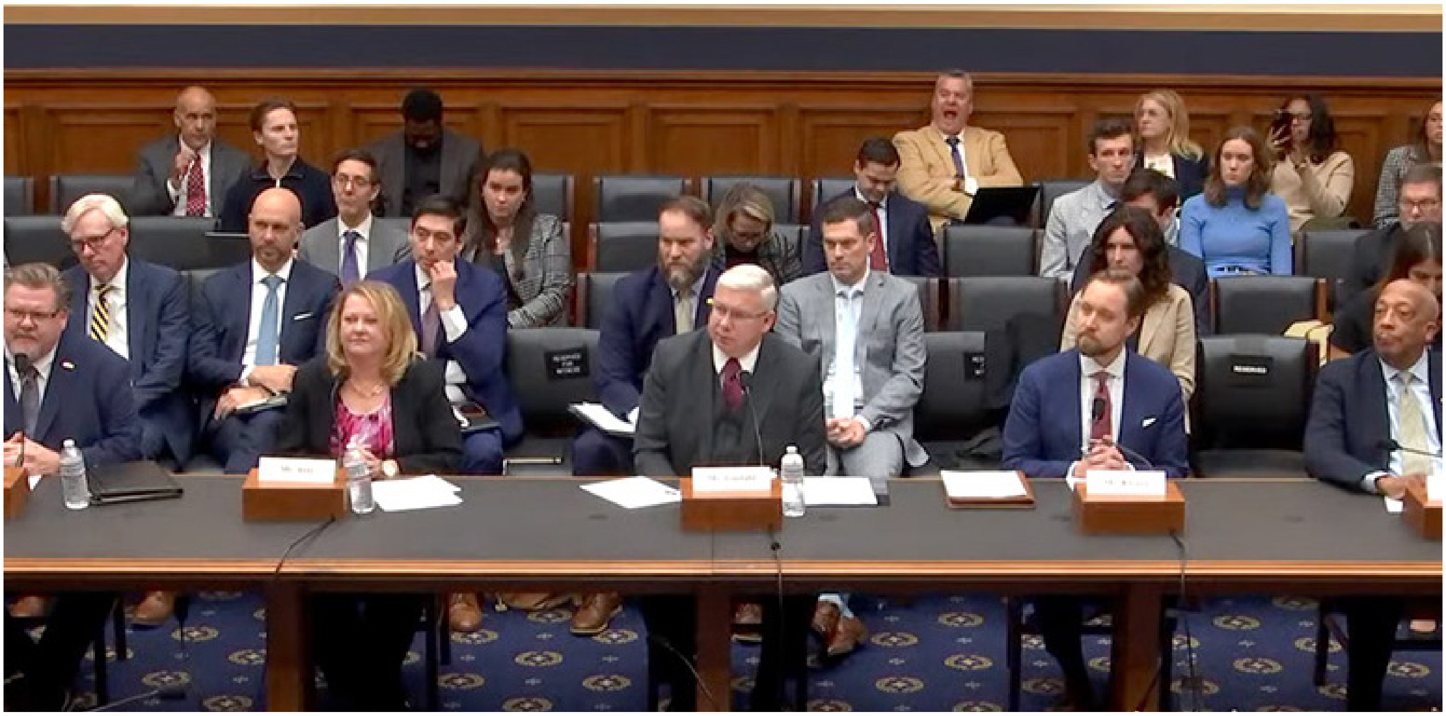
"One of the concerns we have as we run the grid closer and closer to the edge is it becomes more and more critical to not have interruptions. Before, we could have a small event, and it wouldn't have an impact on the reliability of the grid," he said. "But as we push the grid to the limit with new load — data center load, or any kind of load — it just puts a microscope on any hiccup in the system that could happen."

Any kind of event becomes riskier as the system is more tightly balanced, but Kenergy — a Kentucky co-op — is dealing with that by investing in new fiber-optic communication systems so it can better monitor its distribution system and help thwart attacks, Lindahl said.

'Embracing Modernization'

The long-run solution to cybersecurity will include modernizing infrastructure control systems as much as possible because keeping them entirely separate from the internet has proved infeasible, said Harry Krejsa, director of the Carnegie Mellon Institute for Strategy and Technology.

"Digitization has swept our world so thoroughly that even national security networks that are believed to be air-gapped often are found to have accidental and unknown internet connections during regular security sweeps and efforts to ensure their ongoing defensibility from



E-ISAC CEO Michael Ball, Xcel Energy Vice President Sharla Artz, Kenergy CEO Tim Lindahl, Carnegie Mellon University's Harry Krejsa and Idaho National Laboratory's Zach Tudor at the hearing Dec. 2. | *House Energy and Commerce Committee*

adversaries abroad," Krejsa said. "The only way around this challenge will be through embracing modernization from top to bottom."

The economic changes driving up electricity demand are already advancing that work, added Krejsa, who worked in the Office of the National Cyber Director under the Biden administration.

"The energy technologies powering this transition, from onsite generation and battery storage to smart inverters and virtual power plants, were designed from the ground up with software at their core enabling modern cyber security features and the ability to update and evolve in response to emerging threats," Krejsa said. "They are also enabling a smarter, more distributed grid architecture, one that is more defensible, resilient and even self-healing, capable of quarantining disruptions and preventing cascading blackouts."

That transition includes using components from China, which dominates manufacturing in general and "electrotech" specifically. Krejsa recommended a reshoring effort there, but noted also some of the most sensitive national security programs use Chinese components.

"I think it's instructive to take a look at the case of the F-35, which does not have zero Chinese-made components," Kresja said. "The defense industrial base, instead, makes a risk-informed prioritization decision about where the cut line is for components."

Congress could help the power industry and advanced manufacturing parse which components are too sensitive to risk backdoors for Chinese (or other) hackers and which can be reliably sourced from anywhere, he added.

Actionable Intelligence Needed

Information-sharing is vital when it comes to emerging threats, and the Energy Threat Analysis Center (ETAC), set up in 2023 as a pilot program, has helped improve dissemination of information to utilities whose systems are under threat, Xcel Energy Vice President Sharla Artz said.

"The private sector must be supported by the government to address national security risks. An essential component of that support is the timely sharing of actionable intelligence about our adversaries, tactics and their motivations," she added. "Armed with this intelligence, private-sector experts can proactively architect security into their systems, hunt for adversarial activity and mitigate the risks from these threats."

ETAC has already shared important information with the sector on Salt Typhoon attacks, and Artz said Congress should authorize it to become permanent so the partnership can grow and evolve to address new threats.

"Explicit recognition of this program allows industry partners and DOE to shape the joint effort to address the evolving risk landscape and to incorporate needed partners in the work effort," Artz said in written testimony.

E-ISAC's Ball also suggested authorizing ETAC to help further its mission, and he asked Congress to fund smaller utilities' cyber defense and to reauthorize the Cybersecurity Information Sharing Act of 2015. The act is meant to facilitate information sharing and was temporarily extended to Jan. 30, 2026.

"Industry sources report that the law has enhanced response capabilities to cyber incidents and meaningfully advanced information sharing and cyber defense," Ball said in written testimony. "As a private entity, expiration of the law has no immediate negative consequences on E-ISAC operations. However, the law does encourage information sharing with ISACs and other sharing relationships. Reauthorization would support the broader information sharing ecosystem and preserve a highly valued framework for the private sector." ■

DOE's National Petroleum Council Releases Report on Gas-electric Coordination

By James Downing

The Department of Energy released a pair of reports from the National Petroleum Council recommending changes to *gas and electric coordination* and to *permitting* rules for oil and gas.

The council is a federal advisory committee made up of leaders from the oil and gas industry and academia, with power sector interests participating in the coordination report.

"The National Petroleum Council's findings confirm what President Trump has said from Day 1: America needs more energy infrastructure, less red tape and serious permitting reform," Energy Secretary Chris Wright said in a statement Dec. 3. "These recommendations will help make energy more affordable for every American household."

The coordination study shows how rising natural gas and electricity demand are combining with shifting use patterns to "strain natural gas pipelines in key regions of the United States."

"Since natural gas became the dominant fuel for U.S. electricity generation in 2016, the interdependence between the gas and electric systems has deepened — but so have the risks of misalignment," the report says. "The two systems function under fundamentally different commercial, regulatory and operational frameworks."

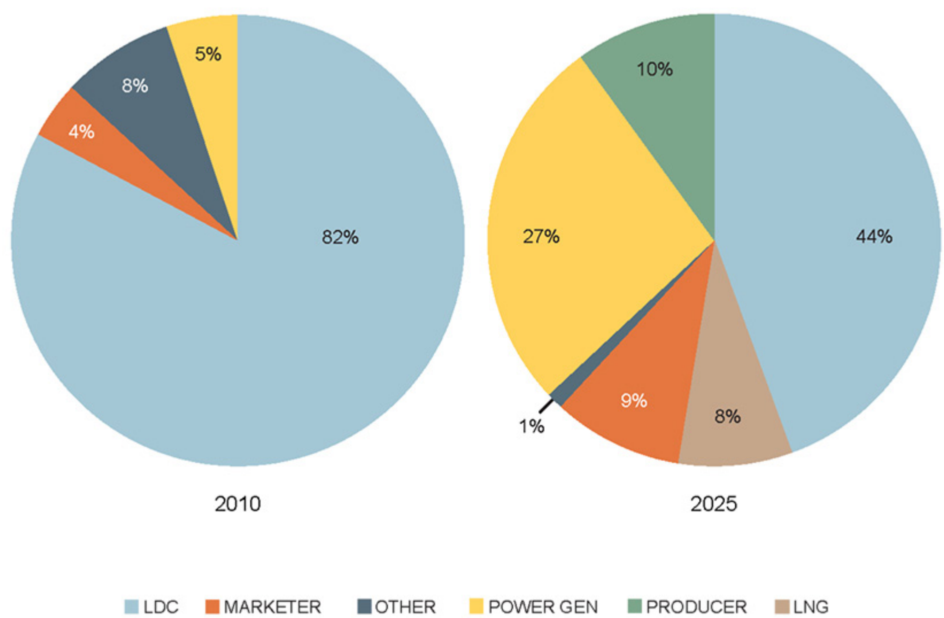
The gas industry is built around long-term contracts and steady demand, while the wholesale power markets are based on real-time market dispatch and hourly price signals. The differences create persistent mismatches in timing and incentives, especially during periods where demand is high for both — most notably during extreme winter weather, the permitting report says.

That issue is bigger in organized wholesale power markets, in which generators depend on hourly price signals and lack the incentives to pay for firm pipeline capacity.

"Their gas procurements rely less on long-term delivery contracts and more on a variety of shorter-term commodity procurements and lower-priority transportation arrangements," the report says. "When the gas and electric systems are both under stress, these arrangements are the first to be curtailed."

Why This Matters

The DOE-coordinated council is the latest group to recommend changes to what has been a longstanding issue with the two industries, one it argues is going to continue evolving as power demand grows over the coming decade.



How the share of firm pipeline capacity by customer class has changed over the past 15 years | *National Petroleum Council*

The two reports both recommend building new infrastructure, with part of the recommended fix to longstanding coordination issues being expanding pipelines. Electricity generation has become the biggest consumer group for natural gas, beating out local delivery companies, as coal plants have retired and been replaced by generators burning cheap shale gas.

"As a result, gas demand has become far more variable and dynamic, with power generators — especially in deregulated markets — often relying on secondary or interruptible pipeline capacity, which amplifies intraday and seasonal fluctuations," the report says. "The rapid expansion of wind and solar resources, which together account for more than 60% of new U.S. generation capacity since 2010, has made gas-fired units essential for grid balancing, requiring flexible fuel supply and rapid ramping capability."

Some pipeline expansion has happened over the past decade, but most of that involved reversing flow directions and adding compressors rather than building new lines. That has helped to meet higher demand, but it has also contributed to fewer flexibilities for generators that would benefit from them.

Storage would also help generators, but the sector has not invested in it, with most expansions being tied to LNG exports, the report says.

The report recommends that Congress and the executive branch take immediate legislative and administrative action to reform permitting to unlock fit-for-purpose infrastructure investment. The two industries should work together to expand new infrastructure to serve generation and prioritize actions to enhance and expand existing infrastructure.

Most previous gas-electric coordination efforts have focused on the few peak winter days, but that risks the broader trajectory of the system, with electric demand poised to rise significantly in the coming decade and some regions' grids shifting to winter peaks from summer, it says.

The report notes that current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products. The two sectors' different business models mean the pipeline sector has not expanded to meet the growing needs of power generation.

The report calls on ISO/RTOs and state and federal regulators to ensure adequate risk-based compensation for gas-fired power generators to get enough fuel and operate reliably when called upon.

FERC should direct ISO/RTOs to conduct comprehensive long-term planning that integrates resource adequacy and fuel assurance considerations, the report says.

On the gas side, the report recommends that policymakers and the industry work to address changing hourly gas flow patterns with alternative tariff structures that enable enhanced gas service offerings and flexible contracting arrangements with generators.

The Natural Gas Council, which is made of trade organizations from that industry, and the Reliability Alliance, which includes the Electric Power Supply Association, Interstate Natural Gas Association of America and the Natural Gas Supply Association, released a joint statement supporting the reports and asking for state and federal regulators to act on its recommendations.

"Time is of the essence," they said. "Policymakers and industry must act swiftly to develop the infrastructure that will win the global energy and AI race while continuing to meet growing demand for affordable, reliable and secure energy. While the natural gas and power industries are fully capable and committed to supporting our nation's expected energy demands, we need additional direction and policy changes from state and federal policymakers to facilitate prompt implementation of these recommendations. We ask Congress, the U.S. Department of Energy, FERC and state commissions to undertake action aimed at ensuring adoption of the recommendations in these reports." ■

DOJ, Constellation, Calpine Reach Antitrust Settlement

Additional Generation Facilities to be Divested in Acquisition

By John Cropley

Under a federal antitrust settlement, Calpine Corp. will divest ownership in several generation assets on the PJM and ERCOT grids as a condition for its acquisition by Constellation Energy.

If approved by a court, the resolution will clear the way for a $26.6 billion transaction that will make Constellation the largest U.S. wholesale power generator.

FERC and regulators in New York and Texas previously approved the deal.

On Dec. 5, *Constellation* and the *Antitrust Division* of the U.S. Department of Justice (DOJ) announced a proposed resolution to the final regulatory hurdle.

DOJ said it was concerned the acquisition could harm competition and raise prices in the PJM and ERCOT grids by more than $100 million a year. DOJ and the state of Texas simultaneously initiated a *civil antitrust lawsuit* (1:25-cv-04235) seeking to block the acquisition and a *proposed divestiture settlement* that would allow it to go forward.

The companies accepted the terms. DOJ said it was the first settlement consent decree the Antitrust Division had filed in a power industry merger in 14 years.

"This settlement includes a six-plant divestiture to an acquisition that risked harming tens of millions of electricity consumers in the mid-Atlantic and Texas," Assistant Attorney General Abigail Slater said in a news release. "I am appreciative of the partnership with our co-plaintiff, the state of Texas, to secure relief for consumers."

The Jack Fusco Energy Center outside Houston, is one of the Calpine generating assets that will be divested as part of the company's acquisition by Constellation Energy. | *Calpine*

Why This Matters

The agreement sets the stage for Constellation to become the largest U.S. wholesale power producer.

Constellation CEO Joe Dominguez hailed the agreement as clearing the way for a foundational step in the next era of American growth and innovation. "We thank the department for its professionalism and tireless work reviewing this transaction through these many months. It's now time for us to complete the transaction, welcome our new colleagues from Calpine and together begin our journey to light the way to a brilliant tomorrow for all."

FERC's approval in July entailed Calpine selling 3,546 MW of generation, all of it in PJM: the 1,134-MW natural gas combined-cycle Bethlehem Energy Center, the 569-MW dual-fuel combined-cycle York Energy Center Unit 1, the 1,136-MW dual-fuel combined-cycle Hay Road Energy Center and the 707-MW simple cycle gas-fired Edge Moor Energy Center. (See *FERC Approves Constellation Purchase of Calpine with Conditions*.)

The proposed antitrust settlement entails sale of York Unit 2, an 828-MW natural gas-fired, combined-cycle plant in Pennsylvania; the Jack Fusco Energy Center, a 605-MW natural gas-fired combined-cycle facility outside Houston; and a minority ownership interest in the Gregory Power Plant, a 385-MW natural gas fired combined-cycle near Corpus Christi, Texas.

When it *announced* the Calpine deal Jan. 10, Constellation anticipated the need for some asset sales in PJM. (See *Constellation to Acquire Calpine for $29.1B*.) ■

NextEra Energy Pursues Gas-fired Data Center Deals

Company Envisions Serving as Much as 30 GW of Load by 2035

By John Cropley

NextEra Energy is pursuing a goal to power 15 to 30 GW of data center hubs by 2035 and a series of nearer-term agreements in the technology sector.

The *2025 Investor Day presentation* Dec. 8 did not mince words: "We are in a golden age of power demand," and NextEra is "America's premier energy infrastructure company."

Until recently, NextEra had been promoting itself as the leading renewable energy developer, but now it is an "all-forms-of-energy company."

The data center hubs are expected to contribute at least 15 GW of new generation by 2035 under a base scenario and 30 GW under an upside scenario. They already have identified more than 20 potential hubs and expect to have more than 40 possibilities by the end of 2026.

Natural gas will play a large role in this, "and we are making excellent progress in our development efforts," the company reported.

Accompanying the projections was a set of diverse announcements, led off with a *partnership* with Google Cloud to develop multiple new gigawatt-scale data center campuses with accompanying power generation and capacity.

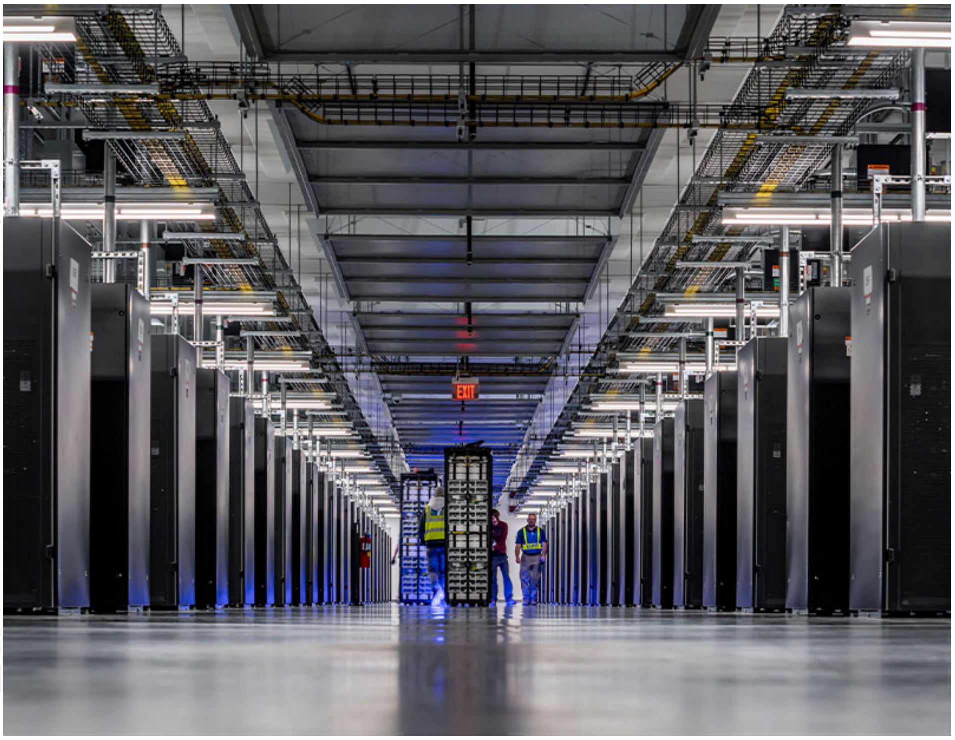
The two companies expect the collaborative approach to speed land development, load interconnection and development of infrastructure.

Additionally, they will collaborate on NextEra's internal digital transformation and use technological innovations and artificial intelligence to accelerate the buildout of data centers and the energy infrastructure supporting them.

In Related News

Why This Matters

The power producer is further positioning itself to power Big Tech.



Meta and NextEra Energy Resources announced 2.5 GW of clean energy contracts to power Meta's data centers. | *Meta*

NextEra Energy Resources and *Meta Platforms* have reached 11 power purchase agreements and two storage agreements totaling approximately 2.5 GW of clean energy. This consists of nine solar projects in ERCOT, MISO and SPP totaling 2.1 GW; two solar projects in New Mexico rated at 190 MW; and 168 MW of battery storage, also in New Mexico. They are expected to come online in 2026 through 2028.

NextEra Energy Transmission and Exelon say they *will partner* to build an approximately 220-mile bidirectional 765-kV line in PJM territory to facilitate more than 7 GW of power generation. The project carries a $1.7 billion price tag; the PJM board's final vote on it is expected in early 2026.

NextEra Energy Resources says it *will acquire* natural gas supply, storage and management company Symmetry Energy Solutions, which has 5,500 commercial/industrial customers and 80,000 mass-market customers in 34 states. The deal is intended to complement NextEra's buildout of gas transmission and gas-fired generation and is expected to close in the first quarter of 2026, pending regulatory approvals.

NextEra Energy Resources and Basin Electric Power Cooperative say they will *explore joint development* of a new 1,450-MW combined-cycle gas-fired power plant in North Dakota to serve as the foundation for a multi-gigawatt data center campus. Under Basin's Large Load Commercial Program, the two submitted an application to the SPP Expedited Resource Adequacy Study process in October.

NextEra Energy Resources is partnering with Comstock Resources on a plan to build up to 8 GW of new gas generation and storage to support hyperscaler data center development in central Texas. Initial power is expected as early as 2027.

NextEra Energy Resources and ExxonMobil are pursuing construction of a 1.2-GW gas-fired, carbon-abated plant on a site with proximity to ExxonMobil's Denbury carbon dioxide pipeline, gas supply and transmission. They are jointly marketing the plant to hyperscalers, and they view it as a proof of concept that could lead to multisite development opportunities. ■

TEP Wins Approval for Data Center Energy Supply Agreement

Capacity Available Through Already-planned Resources

By Elaine Goodman

Arizona regulators approved a 286-MW energy supply agreement between Tucson Electric Power and the developer of an embattled data center project near Tucson.

The Arizona Corporation Commission voted 4-1 on Dec. 3 to approve TEP's agreement with data center developer Beale Infrastructure Group and its affiliate, Humphrey's Peak Power, to supply energy to the Project Blue data center in Pima County.

TEP officials said they won't need new, dedicated resources for the 286-MW agreement. Instead, they'll have capacity from resources already planned through the company's 2023 integrated resource plan. Capacity also will be freed up through expiring wholesale contracts with utilities that now plan to use other market resources, they said, as well as delays and reductions in industrial load.

Commissioners said that without the energy supply agreement (ESA), the developer could simply take service under a large-load tariff — without customer protections that are in the agreement. TEP representatives noted that they're obligated to provide service to customers in its territory.

"I don't think we have an option at 'no,'" Commissioner Lea Marquez Peterson said. "We need to make sure that we have an ESA … that protects all the ratepayers."

Among the protections in the 10-year agreement is a minimum monthly charge that would apply if actual electricity demand is less than the contracted amount. Beale must give at least three years notice to terminate the agreement.

Why This Matters

Approval of the energy supply agreement with TEP is a significant win for Beale Infrastructure, which has faced previous setbacks in its plans to develop data centers in the Tucson area.

TEP's proposed energy supply agreement with a data center developer drew opponents to the Arizona Corporation Commission meeting on Dec. 3, including Lee Ziesche of the No Desert Data Center Coalition. | *ACC*

Power will be provided under a commission-approved rate schedule that would be subject to commission review in future TEP rate case proceedings.

TEP said the agreement would allow it to spread fixed costs across more retail electric sales, reducing the need for rate increases.

Beale will pay TEP the estimated $4 million for two new 138-kV transmission lines to exclusively serve the project. The cost of a new switchyard will be recovered through the utility's FERC open access transmission tariff.

Beale is expected to start taking service in May 2027, ramping up to 286 MW in 2028.

Opponents Speak Out

Project opponents, including many Tucson-area residents, expressed skepticism of the agreement. Some predicted the data center would further increase utility bills for residents, who are already struggling to make ends meet.

"The main question that has not been answered by TEP is, where is this 286 MW really coming from and when are we going to pay for that?" Lee Ziesche of the No Desert Data Center Coalition told the commission. "There is nothing in the energy supply agreement that protects us from paying for generation."

Opponents also questioned the viability of the data center project. Just days before the commission meeting, news outlets reported — based on comments from Pima County supervisors — that

Amazon had pulled out of Beale's data center project.

"As far as we know, Beale doesn't have a customer," a project opponent told the commission.

In an email to *RTO Insider*, a Beale spokesperson pointed to previous public comments from Amazon Web Services saying they had no agreements in place in Tucson. A Beale representative also addressed the issue during the ACC meeting.

"We feel confident that we will have a customer ready by the time the data center comes online," said Sam Arons, vice president of energy and sustainability for Beale Infrastructure.

Commissioner Rachel Walden voted against the energy supply agreement. She shared residents' questions about how generation would be paid for and said the agreement should include more protections, such as a higher buyout rate if the developer pulls out.

"This kind of sets the stage for future contracts," she said.

Annexation Request Rejected

Beale Infrastructure plans to build Project Blue on a 290-acre parcel in Pima County. The county Board of Supervisors approved the sale and rezoning of the county-owned land to Beale in June.

The developer asked the city of Tucson to annex the project site, a step needed to procure water to cool the data center. The developer offered to build an 18-mile pipeline to bring in reclaimed water.

But in August, the Tucson City Council voted unanimously to reject the project, mainly due to concerns about the large amounts of water and energy it would require.

In September, Beale announced an updated design for Project Blue in which a closed-loop, air cooled system would be used for cooling. Under the new design, "minimal" amounts of water would be recirculated through a closed-loop, air-cooled system to provide industrial cooling, Beale said.

The new cooling method didn't change the amount of capacity requested in TEP's energy supply agreement.

Beale has also committed to pursuing 100% renewable energy for its Pima County data center. Initially the data center will be powered by renewable and non-renewable energy, and Beale will buy renewable energy credits to offset the non-renewable power.

Longer-term, Beale plans to work with TEP on developing new renewable resources for the data center, which the developer would pay for.

Future Phases

The energy supply agreement approved Dec. 3 applies only to Project Blue, which is the first phase of Beale's plans for data center development in the Tucson area.

A second project, known as Luckett Industrial, is planned on two parcels in Marana, Ariz. One parcel is served by TEP and the other is served by Trico Electric Cooperative.

"Trico and TEP have both submitted letters stating that they will work with Beale to support the data center's needs without impact to service or rates for [other] customers," a Beale spokesperson said in an email. ■

Colorado PUC Approves Extension for Comanche Coal Plant

Unit 2 Retirement Delayed a Year Due to Unit 3 Outage

By Elaine Goodman

The Colorado Public Utilities Commission granted a one-year extension to Unit 2 of the coal-fired Comanche power plant as uncertainty lingers about the fate of outage-plagued Unit 3.

The commission approved the extension Dec. 3. Comanche Unit 2 now is scheduled to retire by Dec. 31, 2026, rather than at the end of 2025. The 335-MW Unit 2 began operating in 1975.

The commission's decision was in response to a *petition* filed Nov. 10 by Xcel Energy subsidiary Public Service Company of Colorado (PSCo), which is the coal plant's primary owner and operator. PSCo was joined in the petition by the Colorado Energy Office, the state Office of the Utility Consumer Advocate and PUC trial staff. (See *Xcel Seeks Extension for Comanche Coal Plant from Colorado Regulators*.)

Xcel Energy's Comanche 3 coal plant | *KRDO*

The petitioners argued the extension was needed because of the unexpected outage of the 750-MW Unit 3, which began Aug. 12 and is expected to last until at least June 2026.

Other factors contribute to the need to keep Unit 2 open, the petitioners said. Those include growth in the peak demand forecast in PSCo territory and the delay of generation and storage projects because of supply chain and tariff issues.

Notable Quote

"We are in the dark about what any of this costs. We are just in a real reliability pickle because once again Unit 3 has broken in a catastrophic way. And it just so happens that we're already somewhat tight on resources, so now it has really created a significant problem."

— Commissioner Megan Gilman, Colorado PUC

The PUC emphasized the Unit 3 outage was the sole reason for granting the extension.

"Clearly we wouldn't be making this decision if not for the unreliable operation of Unit 3," Commissioner Tom Plant said.

Comanche Unit 3, which went online in 2010, has a history of unplanned outages. From mid-2010 through 2020, the unit averaged 91.5 outage days a year, according to a March 2021 report from the PUC. A 2020 outage lasted much of that year and extended into 2021.

For two years starting in August 2023, the plant has been shut down unexpectedly for part or all of 138 days, according to Western Resource Advocates (WRA).

Unit 3 is slated for retirement by Jan. 1, 2031, as Xcel plans to exit from coal by 2030. Unit 1 retired in 2022.

Commissioner Megan Gilman expressed concern that PSCo might be presuming that fixing Unit 3 is the best path forward. In addition to unknown costs to repair Unit 3, the costs to extend the life of Unit 2 aren't yet known, she said.

"We are in the dark about what any of this costs," Gilman said. "We are just in a real reliability pickle because once again Unit 3 has broken in a catastrophic way. And it just so happens that we're already somewhat tight on resources, so now it has really created a significant problem."

The commission's decision requires PSCo to report to the commission by March 1 on the status of Unit 3. A more detailed report is due by June 1.

Commission Chair Eric Blank said he wants monthly reports from PSCo on costs to fix Unit 3.

"I'm not interested in seeing very large capital expenditures on an after-the-fact prudency review fight," Blank said. "I'd like at least visibility into what's going on ahead of time."

Commissioners noted there would be no presumption of prudence from the monthly reports.

The commission also placed a cap of 3,942,000 MWh on combined generation from Units 2 and 3 in 2026 — a status quo limit that was requested by WRA and other environmental groups. ■

West Needs Unified IBR Approach, WIRAB Says

Group's New IBR Technical Resource Designed to Assist Regulators

By Henrik Nilsson

Western state utility commissioners should encourage "standardization and harmonization" to effectively integrate inverter-based resources throughout the region, according to a guide developed by the Western Interconnection Regional Advisory Body and Elevate Energy Consulting.

The guide, a "technical resource" intended to assist commissioners, is a follow-up to a report on IBRs commissioned by WIRAB in 2024. Elevate Energy and WIRAB *hosted a webinar* to discuss the document and its findings Dec. 2.

The report notes that over the next decade, approximately 85% of new generation in the West is expected to be IBRs. If not integrated correctly, this can lead to vulnerabilities in modeling, coordination and operational performance, according to the report.

To correctly integrate IBRs, the industry must focus on "standardization and harmonization," Ryan Quint, CEO of Elevate Energy, said during the webinar. "In particular, adopting the latest and greatest standards."

"FERC and NERC have said, 'We strongly … encourage folks to adopt [IEEE 2800-2022], but we are not mandating it,' meaning there are no requirements for [the] significant … amount of decisions that need to be made about how we want to configure, control and operate IBRs," Quint said. "So, unless those requirements are specified, there are potential gaps that exist."

Encouraging standard adoption of IBRs is especially tricky in the West because many entities are involved in the process, Quint noted.

Other regions may have one ISO or RTO where all the decisions are made with "one central entity responsible for administering that process and following those rules that have been created or imposing those rules," Quint said.

"In the West, we've got dozens and dozens and dozens of planning coordinators, transmission planners, that all have varying sizes, areas of expertise, challenges of their own," Quint said. "Regional coordination, bringing these entities together in a unified way, is really an important concept, particularly in the West. And that becomes very applicable with the adoption of new standards, the improvement of requirements, the checks and balances that happen during the interconnection process, etc."

Standardization brings reliability benefits to not only transmission providers, but also developers and contractors, who will have a clearer understanding of the rules, Quint said.

Tri-State's Escalante Solar Project near Grants, N.M. | *Tri-State Generation and Transmission Association*

To achieve harmonization, the industry needs a stakeholder-engaged assessment, which would include regional training, support for smaller entities and utility flexibility.

The need to streamline integration of IBRs also applies to large load interconnections, Quint noted.

The technical resource states that commissions "can set expectations, require transparency and ensure utilities are prepared to integrate IBRs without compromising affordability, reliability or resilience."

The resource suggests seven key focus areas for IBR oversight:

- enhanced and harmonized interconnection requirements,
- IBR modeling, data quality and study processes,
- using modern IBR capabilities,
- commissioning practices and post-commissioning monitoring,
- utility operational readiness,
- coordination and sharing across jurisdictions, and
- maximizing capabilities of legacy IBR devices.

Arizona Corporation Commissioner Lea Márquez Peterson, WIRAB's chair, said the goal of the resource is to "equip regulators with clear, practical oversight tools and the kinds of questions that surface potential issues early, drive meaningful conversations with utilities and ultimately support better outcomes for the Western Interconnection as a whole."

"NERC and FERC are strengthening standards, but regulatory oversight varies, and some responsibilities fall on our shoulders as commissioners," Márquez Peterson said. "WIRAB's role is to help bridge the space between complex technical issues and the regulatory decisions that shape reliability. This resource is one way we can support that mission." ■

CAISO Ponders DER Market Participation in New Paper

Market Monitor Asks for Review of 100-MW Limit

By David Krause

A new CAISO paper lays out a series of challenges around how to improve participation of demand response and distributed energy resources in the ISO's day-ahead and real-time markets.

The *paper*, published Nov. 26, compiled information from CAISO Demand and Distributed Energy Market Integration (DDEMI) Working Group meetings held in 2025.

CAISO is committed to enabling "the reliable, efficient and seamless utilization of demand response into ISO operations and markets," the ISO said in the paper.

Under the ISO's current rules, distributed energy resource aggregations and resources that can reduce their load are able to participate in the day-ahead and real-time markets for energy and ancillary services.

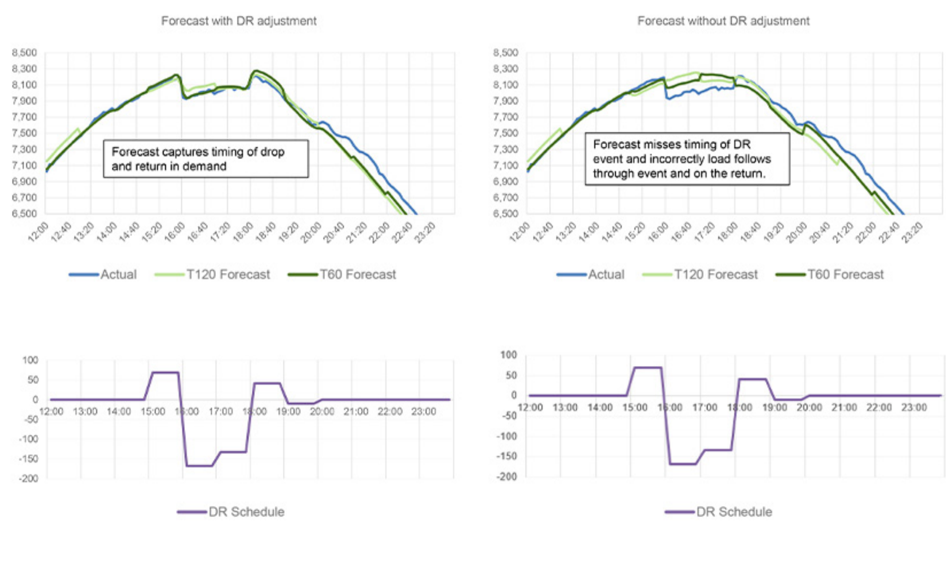
The DDEMI Working Group developed "problem statements" for the ISO to consider as it begins work in early 2026 to expand DER and DR access to its markets. The group identified six topics for the ISO to address:

- expanding performance evaluation methodologies,
- enhancing demand flexibility market options,
- expanding or developing reliability-based DR participation options,
- expanding or developing economic-based DR participation models,
- optimizing market options for direct or indirect participation of DERs and
- expanding demand-side bidding options

However, in Nov. 6 *comments* on the DDEMI initiative, CAISO's Department of Market Monitoring said the ISO has not clarified the costs and benefits of the working group's priority areas and should provide an assessment.

"Without any such assessment, it appears to DMM these enhancements should have a lower priority than numerous other policy efforts currently underway, such as the Extended Day-Ahead Market congestion rent allocation refinements, congestion revenue rights reforms, storage bid cost recovery and default energy bids and uncertainty products," DMM said.

DMM also asked CAISO to develop a new resource model that would allow DR resources to show as demand-side resources, rather than supply-side resources.



Performance forecast with and without accounting for demand response resources | *CAISO*

Why This Matters

CAISO currently allows distributed energy resource aggregations and demand response resources to participate in the ISO's market, but there are some kinks to work out to improve how these resources support the grid.

"Treating demand response as a real-time demand-side resource improves market efficiency by adding slope to the demand curve, which enhances reliability and reduces system costs by avoiding uneconomic load scheduling," DMM said.

However, if demand response is modeled as load, coordination with CAISO's capacity planning framework will be required, DMM said. Demand modeled as load would affect long-term load forecasts and the qualifying capacity of resources.

In the paper, CAISO staff said there is currently no pathway for DER aggregations to qualify for resource adequacy. This issue involves the California Public Utilities Commission, which would need to develop a qualifying capacity approach for DER aggregation RA, the paper says.

For the Reliability Demand Response Resources (RDRR) area, the working group found that reliability demand response programs do not include a resource's startup costs during economic dispatch. The group also found that the RDRR dispatch limit is 100 MW, even if the resource's capacity is more than 100 MW.

DMM asked CAISO to accurately represent RDRR characteristics, such as start-up costs, in the market to help preserve access to these reliability resources.

As for next steps in the initiative, CAISO is now collecting stakeholder feedback about how the ISO should prioritize future DDEMI policy development in the short term (between 2026 and 2027), mid term (2028-2030) and long term (beyond 2030). ■

CPUC OKs PG&E Request for 2026 Diablo Canyon Cost Recovery

Commission Transitions SGIP, Updates Undergrounding Guidelines

By David Krause

The California Public Utilities Commission on Dec. 4 approved Pacific Gas and Electric's request to recover about $382 million from ratepayers to continue operating the Diablo Canyon Power Plant in San Luis Obispo in 2026.

The approved 2026 revenue amount covers operations and maintenance activities, resource adequacy substitution capacity forecasts and fuel from 2025 through 2030, among other items, the *decision* says.

"I know these issues [in the decision] have not been easy," CPUC Commissioner Darcie Houck said. "The extended operations of Diablo Canyon Power Plant are a critical piece of the state's electricity reliability requirements, and PG&E does need to be compensated consistent with the statute."

Diablo Canyon had been scheduled to close by 2025, but in 2023 the CPUC approved a 5-year extension for the plant, keeping its two reactors online until at least 2029 and 2030. The approved 2026 revenue requirement will decrease the average bundled service rate for PG&E customers from about 34.8 cents/kWh to about 34.6 cents/kWh.

The revenue requirement costs will be split among PG&E (44%), Southern California Edison (46%) and San Diego Gas & Electric (10%). The decision requires PG&E to provide a "detailed account" of why it did not seek government funding to offset certain ratepayer costs.

"The tracking of costs is going to continue to be very important to ensure that there is no double recovery at a later date," Commissioner John Reynolds said.

SGIP Refunds

At the Dec. 4 voting meeting, the CPUC also approved a *decision* that closes the ratepayer-funded portion of the Self-Generation Incentive Program (SGIP), setting out the return of leftover money to ratepayers, while establishing rules for implementing the portion of the program financed by the Greenhouse Gas Reduction Fund (GGRF).

The Diablo Canyon Power Plant in San Luis Obispo, Calif. | *PG&E*

The SGIP was implemented more than 20 years ago to provide incentives to certain distributed energy resources on the customer's side of the utility meter to help shave peak demand. Qualifying technologies included internal combustion engines, gas turbines, energy storage systems, and combined solar and energy storage systems, among others.

The structure of the program has gone through multiple iterations, and over time its focus has shifted from reducing peak load to cutting greenhouse gas emissions.

In 2020, SGIP was extended from Jan. 1, 2021, to Jan. 1, 2026, under California Senate Bill 700, which authorized the CPUC to collect $166 million in ratepayer funds per year for the program from 2020 to 2024. In 2022, Assembly Bill 209 removed a requirement that the CPUC administer solar resources separately from other technologies under the SGIP, provided funding for combined solar and storage resources and directed the agency to use AB 209 funds for all residential customers, including those served by publicly owned utilities.

In 2023, SB 102 allocated $280 million in GGRF money to the SGIP and restricted participation to eligible low-income residents installing behind-the-meter storage or solar-plus-storage systems. According to the CPUC's ruling, the GGRF-funded SGIP budget was opened for reservation in June 2025. The program's administrators — namely the state's utilities — are expected to administer the GGRF-funded SGIP similarly to the ratepayer-funded program.

SGIP projects are subject to time-of-use and demand response requirements to support grid reliability and were required to enroll in a TOU rate and DR program for 10 years.

"Once SGIP closes it will be important for the electric investor-owned utilities associated with SGIP projects and customers to monitor ongoing compliance with TOU and DR requirements to ensure that the state is achieving the full ongoing benefits of these systems," the CPUC said in the decision. "This approach will allow SGIP to close before all projects get through the 10-year permanency period while maintaining program and grid benefits."

High Stakes on Undergrounding

The CPUC approved a *resolution* that updates its guidelines for undergrounding electric distribution lines. The updates include new requirements for determining whether cost recovery is reasonable for an undergrounding project; a revised method for choosing the most cost-efficient projects; and an explanation of how to calculate cost-benefit ratios to maximize wildfire risk reduction and minimize costs, among others.

"Our electric grid … has experienced catastrophic failures leading to loss of life and home," Reynolds said. "This has led us in this regulatory space to rethink our approach to risk on the grid."

"We know we will need additional standards to judge what undergrounding projects should be funded by ratepayers … the costs here are enormous," Reynolds added. "We know we will be evaluating 10 to 11 figures in capital costs with average monthly customer bill impacts as high as $25. With stakes that high for a single capital program, we need to get the methodology right."

The CPUC also approved a new rate for 2026 for the state's wildfire fund non-bypassable charge. The new rate of $0.00591/kWh rate will add about $909 million to the fund, according to the *decision*. ■

Ariz. Regulators Slash APS' DSM Plan, Express Support for VPP Programs

By Elaine Goodman

Arizona regulators approved a demand-side management plan for Arizona Public Service that slashed the plan's proposed budget by more than half and eliminated many of its programs — but spared and even encouraged virtual power plant programs.

The Arizona Corporation Commission voted 5-0 on Dec. 3 to approve the scaled-back plan with a budget of $40 million rather than the requested $91 million.

ACC staff recommended approval of APS' DSM plan, finding that the plan's newly proposed programs would be cost-effective.

But Chair Kevin Thompson proposed an amendment, which the commission approved, that slashed the plan's programs and budget.

"I've been anxious to get this matter before this commission so that we can trim some of the bloat and fat from this budget," Thompson said.

Thompson blamed the situation on previous commissions that "condoned and even required these programs to expand to the point where they ballooned beyond the intent of the original goals."

An APS representative said the company didn't oppose Thompson's amendment.

ACC rules require utilities to file a DSM plan. The cost of programs in an approved plan can be recovered through a customer fee.

Among programs the commission rejected were APS' proposed measures to encourage mini-split heat pumps and air conditioners and pool pump recalibrations in existing homes.

The ACC suspended all funding for the residential new construction program, which offered incentives to builders that meet energy efficiency standards in new homes. APS had proposed increasing an incentive, from $100 to $200, for prewiring new homes for EV charging.

Thompson said installing energy efficient appliances in new homes is already required by law.

The ACC axed incentives for electric golf carts, high-frequency golf cart battery chargers and energy-efficient livestock fans. APS said in its plan that golf cart-style utility vehicles are increasingly popular as work vehicles beyond golf courses.

Kerri Carnes, left, and Jeff Allmon of APS address the Arizona Corporation Commission on Dec. 3. | *Arizona Corporation Commission*

Funding was eliminated for the conservation behavior program, which has provided home energy reports and personalized energy-saving tips to about 500,000 residential customers.

VPP Programs Spared

Spared from the chopping block was a home weatherization program for low-income residents.

The commission also saved APS' virtual power plant programs, which include commercial and industrial demand response and the Cool Rewards residential program. Cool Rewards gives a $35 annual credit to customers who agree to have their thermostat setting raised when energy demand increases during a summer heat event.

APS wants to expand Cool Rewards beyond its 4 to 7 p.m. timeframe in June through September. Market prices can still be high from 7 to 8 p.m., said Kerri Carnes, director of customer to grid solutions for APS.

"There have been instances where it would have been nice to call on those thermostats in early October, for instance," Carnes told the commission.

Also spared was a "bring your own device" pilot program for home batteries, which the commission approved in March. APS customers who agree to participate in up to 60 battery-dispatch events from May through October will be compensated with an annual $110/kW capacity payment.

The commission approved an amendment from Vice Chair Nick Myers that directs APS to strengthen its VPP programs.

Myers wants to see APS adopt a "more cohesive" VPP strategy, potentially consolidating separate programs.

"A VPP should not be treated as a niche pilot or a scattered set of incentives," Myers said. "It should operate as a true grid asset — one capable of delivering firm capacity, supporting reliability events and reducing the pressure on ratepayers to build traditional generation or wires solutions prematurely." ■

ERCOT Successfully Deploys Real-time Co-optimization

By Tom Kleckner

ERCOT says it has successfully deployed Real-time Co-optimization + Batteries (RTC+B) into the market, a mechanism used in most other power markets that procures energy and ancillary services in real time every five minutes.

The new functionality, which went live for the Dec. 5 operating day, also includes improvements to modeling and consideration of batteries and their state-of-charge available to provide energy and ancillary services.

CEO Pablo Vegas said RTC+B is the "most substantial" improvement to the real-time nodal market design since its inception in 2010.

"The implementation of this program marks a significant step forward toward more efficient markets and improved grid reliability," he said in a *news release*.

The grid operator said RTC+B's market design is a "key element" in the market's strategic development and will yield more than $1 billion in annual wholesale market savings. It said RTC+B will provide more flexibility in real time for ERCOT to more efficiently procure energy and ancillary services. (See *How ERCOT's RTC+B is a Game-changer for Market Operations*.)

The ISO listed other operational improvements from using resources more effectively:

- using a variety of resources to better manage transmission congestion;
- reducing operators' manual actions and commitments;
- modeling batteries as a single device to effectively dispatch their stored energy; and
- replacing inefficient supplemental reserve markets.

ERCOT staff and market participants have been gearing up for go-live since the program was restarted in 2023. The RTC+B Task Force spent 27 meetings drafting more than 25 protocol changes related to the project and producing training videos. Since May, the task force has been overseeing testing and interactive market trials to stabilize the systems.

ERCOT's Matt Mereness, who chaired the task force, said stakeholders' collaboration and coordination resulted in a "smooth, seamless" cutover.

"This is something ERCOT could not have done alone, so thank you for the journey since May 5," he told stakeholders during a final cutover call Dec. 5. "My gosh! We went live last night. Thank you so much."

The cutover to RTC+B took place at midnight Dec. 4, when telemetry was switched to RTC. Staff reconfigured the market systems' network, creating a risk of disconnecting some qualified scheduling entities (QSEs) — market participants responsible for scheduling energy and financial settlements on behalf of generators, ESRs and other energy providers — that eventually was resolved.

Why This Matters

ERCOT's deployment of Real-time Co-optimization + Batteries into the market adds a mechanism most other power markets already have. The new functionality will yield more than $1 billion in annual wholesale market savings, the grid operator says.

Mereness said "quite a few and [a] not-insignificant" number of QSEs had problems setting their application programming interface (a set of rules and protocols that allows software applications to communicate and interact with each other) to the right endpoint.

"We all needed to step across the line together, and we weren't all making it across the line at the same time," Mereness said. He said everyone's connectivity was reconciled and aligned and by 1:53 a.m., "We were operating on RTC+B."

ERCOT expected 95 QSEs to participate in RTC+B.

Staff closed the day-ahead market at 10 a.m., and ERCOT was off and running with its first real-time co-optimized day-ahead market.

ERCOT's Matt Mereness. | © RTO Insider

The deployment ends an effort that began in 2019 after a *Public Utility Commission directive* to ERCOT. It was delayed for several years after 2021's Winter Storm Uri led to more pressing work for ERCOT staff.

The project added battery energy storage resources with the state's growth of storage. Texas is second only to California in terms of installed capacity, having doubled battery capacity between 2023 and 2025 and now approaching 10 GW.

ERCOT said it will work through the stakeholder-led Technical Advisory Committee in helping determine which initiatives to advance now that RTC+B has been implemented. ■

Big Jump in Ontario Capacity Prices Signals Tightening Supplies

IESO: Minimal Impact on Rates Seen

By Rich Heidorn Jr.

Clearing prices in IESO's latest capacity auction hit a record $645/MW-day (CAD) for summer 2026, nearly double the $332 from last year's, and $725/MW-day for winter, more than five times the previous $139.

Although IESO said the impact on ratepayers will be minimal, observers said the jump is further evidence of tightening supply/demand conditions in Ontario and other organized markets in the Eastern Interconnection.

IESO *said* it procured 1,833 MW of supply for summer 2026 (above the ISO's 1,800-MW target) and 1,125 MW for winter 2026/27 (below its 1,200-MW target).

Ratepayers will feel little impact from the rising prices, IESO said, because its medium- and long-term procurements play a larger role in the ISO's *Resource Adequacy Framework* (RAF). "The total cost of the capacity secured is expected to represent approximately 1% of total system costs," the ISO said in a statement Dec. 4.

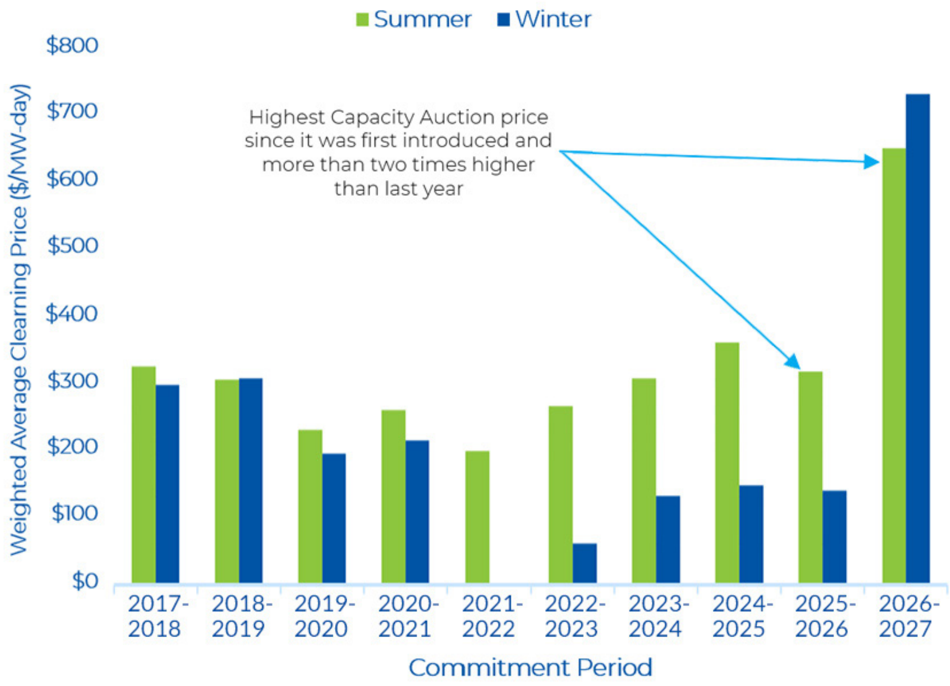
Suppliers who secure an obligation receive payments for *making their capacity available* in the energy market.

IESO spokesman Michael Dodsworth said prices rose because of higher procurement targets and reduced participation by suppliers, some of which secured contracts through other windows of the RAF. Participation also dropped because of a lack of offers by generation-backed imports from NYISO.

"Last year's auction was very successful in securing capacity at a low cost. While this year's prices were higher relative to last year's auction, they are still comparable with the majority of supply under contract," Dodsworth said. "We're still procuring the vast majority of electricity through long-term contracts or other procurements or other mechanisms that have the rates regulated by our provincial regulator," the Ontario Energy Board.

Why This Matters

Although rising capacity prices will have little impact on ratepayers, observers said the jump is further evidence of tightening supply/demand conditions in the Eastern Interconnection.



Capacity auction pricing results for delivery 2017-2027 | *Power Advisory*

He noted that the ISO "a little unexpectedly" raised its target procurements by 200 MW, with summer 2026 rising to 1,800 MW from 1,600 MW and winter 2026/27 to 1,200 MW from 1,000 MW.

Tom Chapman, an energy economist with The Brattle Group who previously served as IESO's senior manager for wholesale market development, agreed that the immediate price impact will be minimal because the auction only makes up about 5% of Ontario's installed capacity.

Chapman said the ISO's 200-MW increase in its summer and winter targets was just one variable that led to the higher prices. "I think the surprise was perhaps on the supply side. While demand response did increase its contribution by about 40 MW, a large New York gas generator did not participate in the auction, and their contribution in previous years was about 300 MW. So, [with the] combination of the increase in target capacity and the reduction in supply, there's about a 400-MW swing from this year to last year."

Tom Chapman, The Brattle Group | *The Brattle Group*

Takeaways

Power Advisory, a consultant for industrial and commercial customers, cited these takeaways in a report to its clients:

- In contrast to the last two auctions, summer prices in the Northwest and Northeast zones were the same as other zones with no locational spreads.
- Although the procurement target was higher, the amount of capacity procured for the winter was lower than that in the last three annual auctions.

- Most of the winter capacity procured was from virtual resources — aggregated DR resources that are not metered by the IESO — while physical resources, including imports, dominated summer capacity. The import capacity limit from Hydro-Quebec increased from 400 MW to 600 MW. But the increase in aggregated DR imports from Quebec was insufficient to fully offset the lost supply from gas plants that won contracts in the most recent medium-term procurement (MT-2).

MT-2 Impact

IESO purchased more than 3,000 MW of capacity in the MT-2 procurement, completed in June, most of it from 27 natural gas and wind generators. (See *IESO Purchasing 3,000 MW of Energy and Capacity*.)

Power Advisory identified five resources that participated in previous auctions and did not receive commitments in this round, including two New York imports — GB II New York and Oswego Harbor Power — and three thermal generators that received MT-2 contracts: Iroquois Falls Power, Kingston Cogen and KAP Power.

"The reduction in summer supply from these resources totaled more than 470 MW," Power Advisory said. "The MT-2 prices for most successful generators are below the effective annual capacity auction price."

In MT-2, IESO purchased 2,006 MW of natural gas-fired capacity beginning in May 2026 and 2029 with a weighted average price of $598/MW-business day.

Tightening Supply in Northeast Markets

Brattle's Chapman said the auction was just the latest indication of tightening supply/demand conditions.

"When you take these results, along with other recent results — in PJM, it cleared at the cap; MISO, where they had record clearing prices; Quebec, where they were a net importer in 2024 and they're facing strong load growth and challenging hydrological conditions — I think it speaks to a broader tightening of supply and demand across the Northeast markets," Chapman said. (See *PJM Capacity Prices Hit $329/MW-day Price Cap* and *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Chapman noted that NERC's Winter Reliability Assessment showed 20 GW of new load since last winter. "It's tough to build 20 GW of supply at the best of times, but [with a] challenging supply chain and … all the interconnection issues, there's [an] imbalance, which the markets are highlighting." (See *NERC Winter Reliability Assessment Finds Many Regions Facing Elevated Risk*.)

"I would say that we should be thankful to the wholesale markets for signaling the underlying market fundamentals in a very transparent, clear way that sends a very powerful signal to system planners, regulators [and] policymakers on exactly what's needed and where it's needed."

Power Advisory also saw the results as the latest sign of tightening supplies. "Energy and operating reserve prices … have been well above historical levels over the past year. We expect energy prices to remain elevated given forecasted demand growth and the retirement of the Pickering Nuclear Generating Station, which will remove 2,100 MW of baseload supply at the end of 2026." (See related story, *Ontario Greenlights Overhaul of Pickering Nuclear Station*.)

"In short, Ontario's grid is getting very 'tight,' and while that first appeared in the energy market, it is now showing up in the capacity market," Power Advisory continued. "With that tightening supply/demand balance across such a large region, procuring capacity through the province's interties will either become challenging from a physical perspective (i.e., the capacity is not available) or expensive."

"If resources from outside Ontario can participate in other capacity auctions (New York and potentially PJM in particular), they need to consider the potential revenues from those auctions compared to Ontario," Brady Yauch, Power Advisory's director of markets and regulatory, explained in an email. "If those prices move higher, the opportunity cost of locking up supply in Ontario is higher, and they would have to adjust their offer accordingly (or would not participate at all)."


Brady Yauch, Power Advisory | *Power Advisory*

Demand Response

Chapman said he was encouraged by the increase in DR.

"This auction is showing that there's still untapped demand response capacity in Ontario, because the demand response providers were able to extract a further 40 MW. And that's even after 10 years of auctions, which is pretty encouraging that there's still that sort of potential in a mature market like Ontario."

Rodan Energy Solutions, which says it is Ontario's largest DR provider with over 300 MW under management, *said* it secured the largest virtual capacity position in the auction.

Power Advisory was less bullish on the potential for additional growth in DR.

"Higher clearing prices should encourage more load customers to offer DR; however, it is not clear how much achievable DR potential remains in Ontario and how quickly new DR supply could enter the market," it said. "If there is insufficient new capacity in future auctions, participants may feel comfortable pushing offer prices higher. Ontario is facing a new reality when it comes to its supply/demand balance and prices."

Reliability Concerns

Chapman said the results show system planners need to expedite their decision-making and give interconnection priority to dispatchable resources.

"Everything will be fine as long as conditions remain normal. There's adequate supply. … But if we see any deviation from that — as SPP and ERCOT saw in 2021 with Winter Storm Uri — it could lead to reliability impacts," he said. "I think that should really focus people's minds on the … need for urgent and quick decision-making. It may require some hard decisions … like which resources should be given priority to connect.

"This is one area I feel that Ontario — I'm not sure whether [by] luck or design — has perhaps got it right under the current market conditions," he continued. "It's a single jurisdiction, and it has launched expedited procurements to meet an identified need. It isn't as overly reliant on a single auction to meet all of its capacity needs; [it doesn't] have all its eggs in one basket. And it seems to have a balance that's perhaps better fit for current conditions than some of the other neighboring markets. I think some of the neighboring markets could learn a few lessons from the Ontario experience, if they are so interested." ■

Ontario Greenlights Overhaul of Pickering Nuclear Station

Project Expected to Cost $26.8B, Extend Reactors' Operation by Decades

By John Cropley

Ontario has approved a $26.8 billion CAD plan to overhaul four aging nuclear reactors that supply approximately 11% of the province's electricity needs.

Ontario Power Generation said the refurbishment of Units 5 to 8 at the Pickering Nuclear Generating Station will extend their operation by up to 38 years.

The Ontario government *announced the approval* Nov. 26, saying the project would protect the province's workforce and long-term energy security while building a more resilient, self-reliant economy in the face of U.S. tariffs.

The OPG facility on the outskirts of Toronto is one of the largest and oldest nuclear power stations in the world. *Units 1-4 began operation* from 1971 to 1973 and have been removed from service. Units 5-8 began operation from 1983-1986 and are *licensed to operate* through the end of 2026.

Units 5-8 are rated at 2.1 GW. Minister of Energy and Mines Stephen Lecce said the project would boost their output to as much as 2.2 GW.

The Pickering refurbishment was greenlit as *OPG nears completion* of a similar project at its Darlington Nuclear Generating Station, 17 miles east of Pickering, that is expected to cost $12.8 billion.

The Pickering project is larger and more complex, including the replacement of all 48 steam generators and the addition of a 1,500-meter deep-water intake structure, neither of which was needed for Darlington.

OPG said more than 7,000 lessons learned through the Darlington overhaul will help shape the Pickering project. The work is expected to begin in early 2027, after final licensing approval by the Canadian Nuclear Safety Commission, and continue through the mid-2030s.

Why This Matters

The decision further cements Ontario's commitment to nuclear power.

Ontario has approved refurbishing four reactor units at the Pickering Nuclear Generating Station. | *Ontario Power Generation*

Approval of the Pickering overhaul was not unexpected, but the plan is not universally supported.

Environmental Defence said Ontario's government had locked the province into a high-cost, high-risk energy strategy that would steer away from wind and solar generation.

There also has been criticism of Canada's decision to emphasize development of advanced nuclear power. (See *Ontario Environmentalists Slam New Nuclear Units*.)

Lecce alluded to the opposition in his Nov. 26 announcement: "After the previous government's attempt to shut down the facility, this refurbishment signals that we are doubling down on Canadian technology, Canadian workers and the Canadian supply chain to protect our economy from global instability."

Nuclear is the leading form of *transmission-connected capacity* in the IESO grid as of September: 12.18 GW, or 32% of total nameplate capacity. In 2024, Ontario's nuclear reactors generated 80 TWh of electricity, or 51% of all power sent to the grid.

The province expects nuclear to remain a central part of its energy portfolio in the future. This was emphasized in "*Energy for Generations*," Ontario's first-ever integrated energy plan, the front cover of which features a sweeping view of the Darlington station. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

OPG is building what is expected to be the first small modular reactor in North America beside Darlington at an expected cost of $7.7 billion. (See *Ontario Greenlights OPG to Build Small Modular Reactor*.) Planned construction of three subsequent SMRs on the same site is expected to bring the total project cost to $20.9 billion. ■

Rosner Voices Support for Large Load ANOPR

By Jon Lamson

Why This Matters

States and consumer advocates have expressed concern that FERC exerting authority over large loads could infringe on state authority and, depending on how rules are designed, may lead to consumer cost pressures and challenges with forecasting load growth.

BOSTON — FERC Commissioner David Rosner was supportive of the Department of Energy's request that the commission assert authority over the interconnection of large loads while emphasizing the importance of collaboration and consensus-building in response to concerns raised by state regulators.

Speaking at a meeting of the ISO-NE Consumer Liaison Group on Dec. 3, Rosner said the Advance Notice of Proposed Rulemaking *submitted* by the department to FERC includes "ideas that I know people in this room have talked about for a long time and that I think we know will work." (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

"I think there's a lot of consensus on: We need to do this because there's a lot of economic development opportunities for the country and states that want to build, but we also need to do it in a way that protects consumers," he added.

Certain aspects of DOE's request have drawn significant pushback from state regulators. A *resolution* passed by the National Association of Regulatory Utility Commissioners stressed that FERC must not assert control over "end-use sales," which are "squarely within the exclusive jurisdiction of state retail energy regulatory authorities."

The resolution also warned that "large load interconnections without sufficient available generation capacity could threaten reliable power service to existing retail customers." (See *Regulators Urge FERC to Honor State Authority over Large Load Interconnections*.)

Expediting the interconnection of large loads, including hyperscale data centers, is a politically sensitive issue across the country. Critics of hyperscale data development point to impacts on energy costs and emissions, as well as the *relatively limited* number of people the facilities employ. Growing bipartisan pushback against data centers has blocked or delayed about $64 billion of investments over the past two years, according to a recent *study*.

The ANOPR floats the idea of processing large load interconnections within 60 days, which has caused some concern about effects on load forecasts. In regions with wholesale markets, rules encouraging co-location could remove generation from the market and drive consumer costs up.

Regarding the controversial aspects of DOE's request, Rosner said he is excited to work with his fellow commissioners "to figure out which of these levers do we need to pull on to solve this problem."

He said the benefit of an ANOPR proceeding is that because it is a generic rulemaking, commissioners can have open conversations with stakeholders to build consensus.

Reflecting on his work on Order 1920-A, he stressed the importance of state buy-in. Working closely with then-Commissioner Mark Christie, "one of the things that we did was to dramatically elevate the state role and state input into the development of those plans." (See *FERC Order 1920-A Wins Approval with Accommodations to States*.)

Getting states to agree on transmission cost allocation plans "de-risks the ability of the utility to actually build these projects, and it makes them more likely to actually get sited," he said, noting that FERC does not have authority over transmission siting, except in "very rare cases that have never worked."

Rosner also emphasized the importance of the independent, bipartisan structure of FERC, which he said is "fundamental to having durable solutions."

"It's a good model, and it didn't happen by accident," he said. "I know there's some litigation in the courts about the president's ability to exert influence over these agencies and make staff decisions, and we'll see what happens."

The Supreme Court heard oral arguments Dec. 8 for *Trump v. Slaughter*, a case that could lead to rollbacks of limits to the president's ability to fire members of independent agencies. (See related story *Supreme Court Justices Seem Skeptical on Agency Independence*.)

New England Issues

Rosner also commented on several New England-specific issues, including capacity accreditation, asset condition projects and the region's gas constraints.

He said ISO-NE's efforts to establish an internal, non-regulatory entity that reviews spending on asset condition projects — potentially enabling third parties to challenge costs with FERC — appears to be a step in the right direction. (See *ISO-NE Gives Update on Asset Condition Reviewer Role*.)

Regarding ISO-NE's work on capacity accreditation, he said it will likely benefit from learning from reforms that have been implemented in other regions.

"I am really encouraged by New England's move toward accreditation," he said. "What I like about tools like this is that they send signals to the private sector and to our state policymakers — who I know play a big role in what gets built here — of, 'here's how your investment will pay off.'"

He also said he remains concerned about the region's constrained access to pipeline gas.

"I have worries about making sure that lights stay on and will stay warm and safe in our home," he said. "I do want to have a sort of all-options-on-the-table approach to this."

During peak periods, there may be opportunities to increase efficiency across the gas and electric systems through artificial intelligence, Rosner said. He also pointed to success in California around using demand response to shift natural gas use throughout the day, saying, "I wonder if there's the potential for using that here." ■

NEPOOL Supports First Phase of ISO-NE Capacity Market Reform

By Jon Lamson

ISO-NE CEO Gordon van Welie and COO Vamsi Chadalavada at the RTO's open board meeting in November | *© RTO Insider*

BOSTON — The NEPOOL Participants Committee voted nearly unanimously to support the first phase of ISO-NE's Capacity Auction Reform (CAR) project, which would transition the region to a prompt capacity market and reduce the notification timeline for generator deactivations from about four years to one year.

ISO-NE Forward Capacity Auctions historically have been held over three years prior to each capacity commitment period (CCP). Under the proposed prompt auction format, auctions would be held about a month prior to each CCP.

RTO officials have said moving to a prompt auction would help address issues related to "phantom entry" — in which new capacity resources fail to achieve commercial operations in time to meet their supply obligations — and challenges associated with forecasting demand three years into the future.

The changes are intended to take effect for the 2028/29 capacity auction. While the proposal is designed to be able to stand on its own, ISO-NE plans to file an additional set of changes that also would take effect for the 2028/29 CCP. The second phase of CAR centers around capacity accreditation and splitting commitment periods into winter and summer seasons.

The prompt market changes generally are viewed as the less controversial of the two phases, though developing the proposal still requires extensive work and stakeholder engagement to reach a consensus on the details of the new design.

In Other Business

ISO-NE COO Vamsi Chadalavada gave updates on the Nov. 23 capacity scarcity event and a recent spike in costs in the day-ahead ancillary services market.

Under the prompt framework, only resources that have proved they are commercially viable would be able to participate in capacity auctions. The proposal would shorten the qualification process, eliminate annual reconfiguration auctions and move the auction from a descending-clock format to a sealed-bid format.

Much of the stakeholder discussions centered around changes to the resource retirement process, which ISO-NE views as a necessary component of the shift to the prompt market. Under the new prompt framework, ISO-NE proposes to separate resource retirement from the capacity auction process.

"The current four-year lead time to retire under a forward market would be replaced with a requirement that a resource submit a binding, irrevocable deactivation notice one year in advance of the start of the delivery period," ISO-NE wrote in a *memo* published prior to the Dec. 4 PC meeting.

At the meeting, several stakeholders praised ISO-NE for its receptiveness to stakeholder input throughout the process. However, multiple participants voiced lingering concerns that moving to a prompt market may increase market volatility, especially as demand grows and the balance of supply and demand tightens.

Others have expressed concerns about impacts on resource development. Under a prompt auction, resources would have no certainty about capacity prices when making development decisions.

However, proponents of a prompt market have argued that the forward capacity market has done little to incentivize new development following the elimination of the seven-year price lock for new entrants in 2021. A general increase in the time it takes to develop most new resources has made it difficult to develop new resources based on capacity market outcomes. (See *FERC Orders End to ISO-NE Capacity Price Locks*.)

One stakeholder said they remain worried that a one-year deactivation notification timeline would increase the risk of reliability-must-run agreements.

Despite the handful of concerns, the proposal passed with broad support and just one opposition vote at the PC, after receiving widespread support from NEPOOL technical committees in November.

ISO-NE said it plans to incorporate a stakeholder amendment to maintain existing rules around "ambient air de-list bids," which allow participants to reflect in capacity offers the physical limits of resources at high ambient temperatures. This amendment received 83% support from the Markets Committee in November. (See *NEPOOL Committees Support ISO-NE Prompt Capacity Auctions*.)

ISO-NE said it plans to file the changes with FERC by the end of 2025. Stakeholder discussions of the second phase of the CAR project are ongoing; ISO-NE is targeting a second filing by the end of 2026.

Operations Updates

Also at the PC, ISO-NE COO Vamsi Chadalavada gave an update on RTO operations, noting that energy market value for November 2025 was up by about 40% compared to November 2024.

He added that ISO-NE is closely following a spike in prices in the day-ahead ancillary services market; average daily day-ahead ancillary service costs have increased by about 260% since September.

ISO-NE launched the day-ahead ancillary services market in March. It plans to formally discuss how the market is working — along with any changes that may be necessary — with stakeholders in March 2026.

"We still think some time is helpful to go through the winter cycle to see how it performs in the winter," Chadalavada said, adding that he remains confident in the basic design of the market.

"The objectives are not going to change. It is, for us, I think the best way to secure those services," he said.

Chadalavada also discussed the capacity deficiency conditions that occurred Nov. 23, noting the event was triggered by unexpected outages at three gas-fired plants, along with higher-than-forecast load and lower-than-expected net imports. (See *Unexpected Generation Loss Triggers Capacity Deficiency in ISO-NE*.)

Initial data indicate the average balancing ratio for the event was 69.3%, while Pay-for-Performance penalties and credits totaled an estimated $34.7 million, he said.

The balancing ratio determines each capacity resource's responsibility to provide energy and/or reserves during scarcity periods, while resource performance relative to these responsibilities determines charges and credits. ■

New England Energy Executives Debate Markets, Affordability

By Jon Lamson

From left: Cheryl LaFleur, ISO-NE board; Sherman Knight, Competitive Power Ventures; Justin Trudell, First-Light Power; Curt Morgan, Alpha Generation; and Sarah Wright, Hull Street Energy | © *RTO Insider*

BOSTON — An increasing political anxiety around energy affordability permeated debates about wholesale market changes, federal policy and demand growth at the annual New England Energy Summit on Dec. 2.

Speakers at the event, hosted by the New England Power Generators Association (NEPGA) and the Dupont Group, grappled with how to lower consumer costs while simultaneously supporting the development of new generation and transmission infrastructure needed to keep pace with accelerating demand growth.

Panelists also expressed differing views on how prepared the ISO-NE markets are for a rapid increase in demand.

NEPGA President Dan Dolan stressed that wholesale markets have not been the cause of rising retail energy costs in New England, noting that capacity prices have remained low in recent auctions.

These low prices have contributed to "a four-year major retirement cycle with over 3,000 MW going away," Dolan said.

He emphasized the need to first ensure the markets are sending the right signals, and then let them operate, even if that leads to periods of high prices. To allow the market to respond to high prices, state and federal policymakers must focus on lowering barriers to development, he said.

He acknowledged that this is "easy to say, but extraordinarily politically challenging to implement."

'Massive Stress'

Why This Matters

The discussions highlighted the difficulty of managing political fallout from price volatility and balancing market improvements with market stability.

ISO-NE CEO Gordon van Welie said the transition to wholesale markets has brought major cost savings to the region over the past 25 years, in part by helping to shield consumers from poor investments. But there is still work to do, he said.

"There was a moment in 2019 when we seriously considered abandoning the capacity market," he said, pointing to problems in the RTO's Forward Capacity Market related to forecasting, phantom entry and accreditation. Its ongoing Capacity Auction Reform project is intended to address these issues for the 2028/29 capacity commitment period (CCP).

Van Welie added that the region would benefit from a more robust bilateral trading regime, which could help reduce volatility for consumers. He expressed hope that the RTO's proposed transition to a prompt capacity auction — in which auctions would be held about one month prior to each CCP — would "push people more into bilateral contracting."

While ISO-NE's prompt market proposal has garnered strong stakeholder support, some NEPOOL members have voiced concern that the shift to a prompt market could increase inter-annual price volatility, while adopting a seasonal market would introduce intra-annual volatility. Some stakeholders have asked the RTO to look at ways to encourage bilateral trading to hedge the volatility risks.

Van Welie, who is retiring from the RTO at the end of the year, said market volatility increases the likelihood of political intervention — such as price caps — in the markets.

He added that politicization around energy has already increased in recent years, creating "massive stress" within ISO-NE, with various groups often blaming the RTO for issues outside of its control and politicians using the RTO "as a piñata."

"It's escalated to the point of bomb threats and death threats, and I think that's really not a good place to be," he said.

Yin and Yang

Referring to the political blowback that occurred in PJM following skyrocketing capacity prices, Anthony Crowdell, senior analyst for Mizuho Americas, expressed pessimism about the future of wholesale markets in a world of rapidly growing demand.

"I think that politicians will end up blowing up the markets," Crowdell said.

Regarding offshore wind development, he said the Trump administration's efforts to undermine the industry appear to have done irreparable damage.

"Unless it is a state entity or a federal entity building it, offshore wind is done in the United States," Crowdell said.

Justin Trudell, CEO of FirstLight Power, said changes in federal policy have caused the company to shift some investments to Canada.

"The next hundreds of millions of dollars that we invest through FirstLight are going to be in Ontario and, likely, in Quebec," Trudell said.

"What we're seeing in Canada is when you do have alignment with the provincial and federal governments, you're seeing explosive growth," he added.

Other speakers downplayed the Trump administration's long-term effects on energy development.

"I think there's a lot of noise in the current administration, but I don't see a lot of tangible things," said Curt Morgan, CEO of Alpha Generation. He added that, beyond the offshore wind industry, "I don't think they've moved the needle that much."

Sherman Knight, CEO of Competitive Power Ventures, echoed Morgan's comments and said the federal policy changes have not shifted the company's priorities in the 2030-2035 time frame.


NEPGA President Dan Dolan | © *RTO Insider*

"I think we have to think about it from a more fundamental standpoint of what's going to work," he said. "There's so much uncertainty over that long period of time, and you just can't develop and build even within an administrative cycle."

With significant demand growth on the horizon, Morgan stressed the need to stop the cycle of generator retirements. He criticized ISO-NE's Pay-for-Performance (PFP) rules, which have led to significant penalties for slow-start thermal generators during capacity deficiency events.

"I have some real concerns about how we're treating existing generation. But I tell you, over time, that generation is going to become as valuable as gold," he said.

He also criticized the frequency of rule changes in the ISO-NE capacity market.

"Almost every year, we're making a tweak or a change to the capacity market," Morgan said. "People don't believe the markets are going to be allowed to work, and frankly they haven't been allowed to work."

ISO-NE board Chair Cheryl LaFleur said that hints at an "age-old dilemma" that frequently came up during her time at FERC.

"People say 'stop making changes, do not make any changes … except fix [PFP], fix ancillary services — just make my change, then stop making changes.' It just seems to be the constant yin and yang."

"I didn't say it was easy," Morgan responded. ■

Raab Associates' Restructuring Roundtable Looks Back on 30 Years

By Jon Lamson

BOSTON — Raab Associates held its final New England Electricity Restructuring Roundtable on Dec. 5, bringing reflections from speakers about the legacy of restructuring and the future of the power sector in the region.

Several speakers praised the Roundtable for consistently bringing together a wide range of perspectives and interests, and helping to promote collaboration and consensus among stakeholders.

"The diversity of perspectives that are at the table is pretty incredible," said David Cash, former EPA regional administrator for New England. "There are people here who have sued each other; there are people here who are competitors."

Dan Sosland, president and co-founder of the Acadia Center, said the Roundtable has been somewhat unique among power industry events for its inclusion of climate and environmental perspectives.

"At the Roundtable we were co-equals," Sosland said. "We were included, and that's a testament to" Raab Associates President and Roundtable convenor Jonathan Raab.

The Roundtable was founded in 1995 to bring stakeholders together to discuss the details and challenges of electricity industry restructuring. It opened to the public after Massachusetts passed its restructuring law in 1997, and Raab Associates formally took over the event from the Massachusetts Department of Energy Resources in 2000.

As the states worked through the kinks of restructuring, the Roundtable gradually became "much more of a policy forum," said Raab, who helped found the Roundtable and moderated the events for most of the 30-year run.

In 2026, the consulting firm Apex Analytics will take control of the Roundtable. The company was selected through a competitive request for proposals and plans to hold its first event in March.

"The Roundtable's strength lies in its adaptability and commitment to discussing meaningful substance around the evolving energy landscape," said Matt Nelson, principal at Apex and former chair of the Massachusetts Department of Public Utilities. "Our team is committed to maintaining that core while thoughtfully exploring ways to evolve and provide relevant content as industry needs change."

Phil Giudice (left), board chair for FirstLight Power, and Jonathan Raab, president of Raab Associates | © RTO Insider

What's Next

The consulting firm Apex Analytics will assume control of the Roundtable in the coming year, with the first event planned for March 2026.

Reflections on Restructuring

The event also may mark ISO-NE CEO Gordon van Welie's last public appearance at the helm of the RTO he has led since 2001. (See *Retiring ISO-NE CEO van Welie Reflects on 25 Years at the RTO*.)

He emphasized the progress that has been made around collaboration in the region, saying, "Even when things do seem a bit tense, we've developed mechanisms to deal with those frictions."

Restructuring and the move to wholesale markets have brought customers significant savings, though not all initiatives have worked as well as he would have liked, he said.

"I would say we made a mistake in going to the Forward Capacity Market back in 2004," van Welie said, adding that it "became too much of a crutch" for ensuring resource and energy adequacy.

ISO-NE's proposed move to a prompt capacity market will "hopefully stimulate bilateral contracting," he said. "The market needs to invest more on a foundation of bilateral contracting with the spot capacity market really being a deficiency charge for somebody who's not fully hedged."

Rebecca Tepper, secretary of the Massachusetts Executive Office of Energy and Environmental Affairs, praised ISO-NE's reliability record.

"ISO-NE has never had to call a control outage in its history," Tepper said. "It's something that we shouldn't take for granted and a huge benefit for consumers."

"Some of it has been luck — we dodged the bullet once or twice — but a lot of it has been operational awareness and market design," van Welie said.

Tepper said it has taken longer to get the retail side of restructuring right, pointing to the lingering problem of predatory supply practices that target residential customers. The growth of municipal aggregation programs in Massachusetts in recent years has enabled better protections and options for residential customers, she said.

As the ongoing deployment of advanced metering infrastructure in the region enables new rate designs that incentivize shifting demand away from peak hours, van Welie said New England should consider "a more command-and-control structure for [demand response]," allowing customers to give up some control of their home appliances in exchange for a lower rate.

Looming Supply Challenges

Both van Welie and Tepper also emphasized the need to focus on bringing in new sources of supply to meet rising demand, and Tepper said regional collaboration will be essential to addressing looming supply challenges.

Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection, said the states are "working on multiple multistate RFPs; that is becoming much more of the norm than the exception."

Several speakers stressed the importance of demand-side innovation, new programs and rate reforms to help prevent supply issues in the coming decades.

While most demand growth projections forecast peak demand to roughly double by 2050, "I don't think these have to be written in stone," said Jamie Dickerson, senior director of energy and climate programs at Acadia. He pointed to a Brattle Group study indicating that grid flexibility could reduce New York's 2040 winter peak by about 21%. (See *Study Finds Considerable 'Grid Flexibility' Potential in New York*.)

Jesse Jenkins, a Princeton University associate professor focused on the decarbonization of energy systems, echoed Dickerson's comments and said even greater demand flexibility gains may be achieved if costs come down for technologies like thermal storage.

"There are lots of ways we can cut [peak demand forecasts], including ground-source geothermal, which is often twice as efficient, if not more, than air-source heat pumps," he said.

Dickerson also stressed the importance of energy efficiency investments while urging policymakers to find more progressive ways to fund EE programs, including through the tax base.

"We do need to lean on those with a greater ability to pay," he said. ■

MISO Declines Stakeholder Ask for Pause on 2025 Queue to Clear Backlog

By Amanda Durish Cook

MISO said it will not postpone the kickoff of a study on its 2025 cycle of interconnection requests, rebuffing stakeholders' requests for a slowdown to clear some of the queue's four-year backlog.

"MISO doesn't want to be looked at as slowing down the queue process. We do think we're ready to kick off. … We're committed to Jan. 5," Manager of Generation Interconnection Ryan Westphal told the Interconnection Process Working Group during a teleconference Dec. 2.

Westphal said MISO would commence studies on the 2025 cycle of projects on Jan. 5, 2026, as scheduled.

Some stakeholders have advised MISO to delay the first studies on the 2025 queue cycle until the RTO is further along processing projects that entered three and four years ago, allowing developers to reach decisions on whether to continue with their plans. (See *Stakeholders Ask MISO to Pause '25 Queue to Get a Handle on 4-Year Backlog*.)

But Westphal said FERC Order 2023 requires MISO to begin new interconnection study cycles 90 days after it closes an application window.

Westphal said MISO would have to seek a waiver with FERC to delay studies and cannot assume the commission would approve it, leaving the RTO no choice but to forge ahead with the early January timetable. He said MISO is working on prescreening the 2025 entrants.

"Seeking a waiver to postpone the 2025 cycle could be construed as MISO trying to slow down our queue process, which is directly counter to MISO's direction to complete queue cycles in 373 days," Westphal said.

Some stakeholders remain adamant that there are too many unknowns following study results to simultaneously process four years of interconnection requests.

REV Renewables' Humberto Branco said the 2023 cycle is essentially a "wild card." He said MISO trying to manage all cycles across all regions "just to get it done" is too much.

"There is some uncertainty there, I acknowledge that," Westphal said. "We have to move these cycles forward as best we can." He added that even later-stage queue projects fall victim to restudies.

Westphal said MISO continues to automate what it can using Pearl Street's *SUGAR* (Suite of Unified Grid Analyses with Renewables) software. He said the RTO is now focused on automating some aspects of model building. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

Westphal said MISO only includes network upgrades for generation projects that have made it to the third phase of the queue in its base case modeling. He said those upgrades are the most likely to be constructed and not disrupt lower-queued projects. Westphal said MISO doesn't want to give developers unrealistic cost responsibilities.

MISO Director of Resource Utilization Andy Witmeier said interconnection customers can mitigate the risk of higher-than-expected network upgrades by using model data posted by the RTO in their own analyses.

"The status quo is no longer acceptable. We have to continue to move these queue cycles forward to get this cleared and move to a one-year queue process," Witmeier told stakeholders.

Ameren Missouri

MISO's Central and West planning regions still have projects in the queue from the 2021 cycle. Westphal said MISO is "trying to wrap up" those projects in early 2026.

The 2022 cycle — MISO's largest — will emerge from the three-part queue's second phase in early 2026. The RTO meanwhile expects the 2023 cycle to enter the second phase of studies late this year and conclude in early April 2026, while the 2025 cycle will finish up the first phase in mid-April.

Altogether, MISO has 174 GW worth of projects in its queue, a value that has fallen from 312 GW at the beginning of 2025. (See *MISO Interconnection Queue Dips Below 175 GW*.)

Coalition of Midwest Power Producers' Travis Stewart said he appreciated MISO's engineering efforts but asked staff to post projected dates according to when it could "realistically" reach milestones, not just the tariff-defined deadlines. He added that he has noticed the RTO is processing queue cycles noticeably faster now.

"It feels, from my perspective, that the pendulum has swung in terms of timing," Stewart said.

Westphal agreed that MISO is seeing speedier results. He said the RTO is poised to complete the 2025 cycle in the span of a year.

"We've all got to be ready to move fast, and not just MISO, to get these cycles processed," Westphal said. ■

The Bottom Line

MISO has decided against taking a breather before it begins studies on its 2025 cycle of generator interconnection requests in early January 2026. Stakeholders asked MISO to consider a delay to focus on projects in the 2021, 2022 and 2023 cycles that aren't completed.

MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class

By Amanda Durish Cook

MISO announced it will study 6 GW of mostly natural gas-fired generation projects in the second group of entrants under its interconnection queue fast track.

The grid operator *accepted* 15 proposals totaling 6.1 GW of new installed capacity Dec. 1. Natural gas additions account for almost 4.3 GW of the projects. In-service dates range from Dec. 1, 2027, to Aug. 6, 2028.

Days before announcing the second list of projects for expedited study, MISO received FERC's permission to increase the number of projects it can accept for study from 10 to 15 per quarter. (See *FERC Allows MISO to Increase Project Count in Queue Fast Lane*.)

MISO's first expedited cycle of generation projects was similarly gas-heavy, representing about 4.3 GW of the 5.3-GW class. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class*.)

The largest gas plants MISO marked for study this time are Invenergy's proposed 1.2-GW gas plant for Wisconsin Electric's customers; Entergy Texas' 820-MW Legend gas plant in Jefferson County, Texas, to serve industrial customers; and Entergy Mississippi's pair of proposed 768- and 763-MW gas plants to accommodate load growth and data centers.

MISO agreed to study battery storage proposals from Ameren Missouri, Entergy Louisiana and DTE Electric that range from 208 MW to 350 MW. The second cycle study list includes solar and wind projects in Minnesota, Michigan and North Dakota.

The Bottom Line

MISO is up to 25 generation projects in its interconnection queue express lane after acceptance of the second cycle. The 11.4 GW designated for expedited study so far would come mostly from natural gas units.

Entergy Texas' Orange County Advanced Power Station under construction in November | *Entergy*

"Cycle 2 builds on the momentum of Cycle 1 and reflects the continued demand for timely, reliable interconnection solutions. These projects are essential to meeting near-term reliability needs and ensuring new resource additions are online to meet load growth," MISO Senior Vice President Aubrey Johnson said in a *press release*.

Johnson said MISO views the fast lane as "one of several tools we're using to meet the evolving needs of our members and the communities they serve." He added that MISO remains intent on cutting down the wait times in its regular generator interconnection queue through the annual megawatt cap and automated software.

Environmental groups have disputed MISO's and SPP's queue fast tracks at the D.C. Circuit Court of Appeals, arguing the processes are unfair and allow primarily fossil fuel generation to leapfrog lengthy queue lines while ratepayers fund grid upgrades necessary to host them. (See *Enviros Challenge MISO, SPP Queue Express Lanes*.)

MISO reported that so far, utilities and developers have submitted 51 projects totaling almost 30 GW for consideration in the expedited queue. The RTO accepts applications for the queue fast lane continually. It plans to leave its application window open until it has studied 68 interconnection requests or May 10, 2027, the application deadline for the final cycle.

MISO has committed to studying a maximum of 68 projects before it retires the temporary express lane process no later than Aug. 31, 2027. Of the 68 spots, 10 are reserved for submissions from independent power producers, with an additional eight set aside for entities serving MISO's retail choice load in downstate Illinois and a percentage of Michigan.

The RTO said three of the first set of 10 fast-tracked projects have struck generator interconnection agreements, with the other seven poised to execute their agreements before the end of 2025.

MISO will announce another fast lane study *cycle* in early March 2026. ■

MISO Floats ‘Zero Injection’ Agreements to Bring Co-located Gen Online

By Amanda Durish Cook

MISO is considering a new type of interconnection agreement for generation built on site and strictly for new large loads.

Marc Keyser, with MISO’s external affairs team, said the RTO wants to introduce “zero-injection generator interconnection agreements.” Under the agreements, generators built solely to serve a data center or other large load customer would connect to the grid without the ability to inject power into the grid and serve load solely at the same interconnection point.

“Let’s explore this hypothesis of zero-injection generator interconnection agreements. … We’re hearing our members say, ‘Please move quickly. Please help us facilitate large load interconnections.’ So, this is one way of doing it,” Keyser told stakeholders at a Planning Subcommittee meeting Dec. 3.

Keyser said zero-injection GIAs could benefit large load customers, with MISO recognizing on-site generation in interconnection studies, “potentially reducing network upgrade requirements to interconnect.”

“The intent here is speed,” Keyser said, adding that MISO could “reflect the reality” in its queue analyses that some new generators are built solely to serve a single large-load customer.

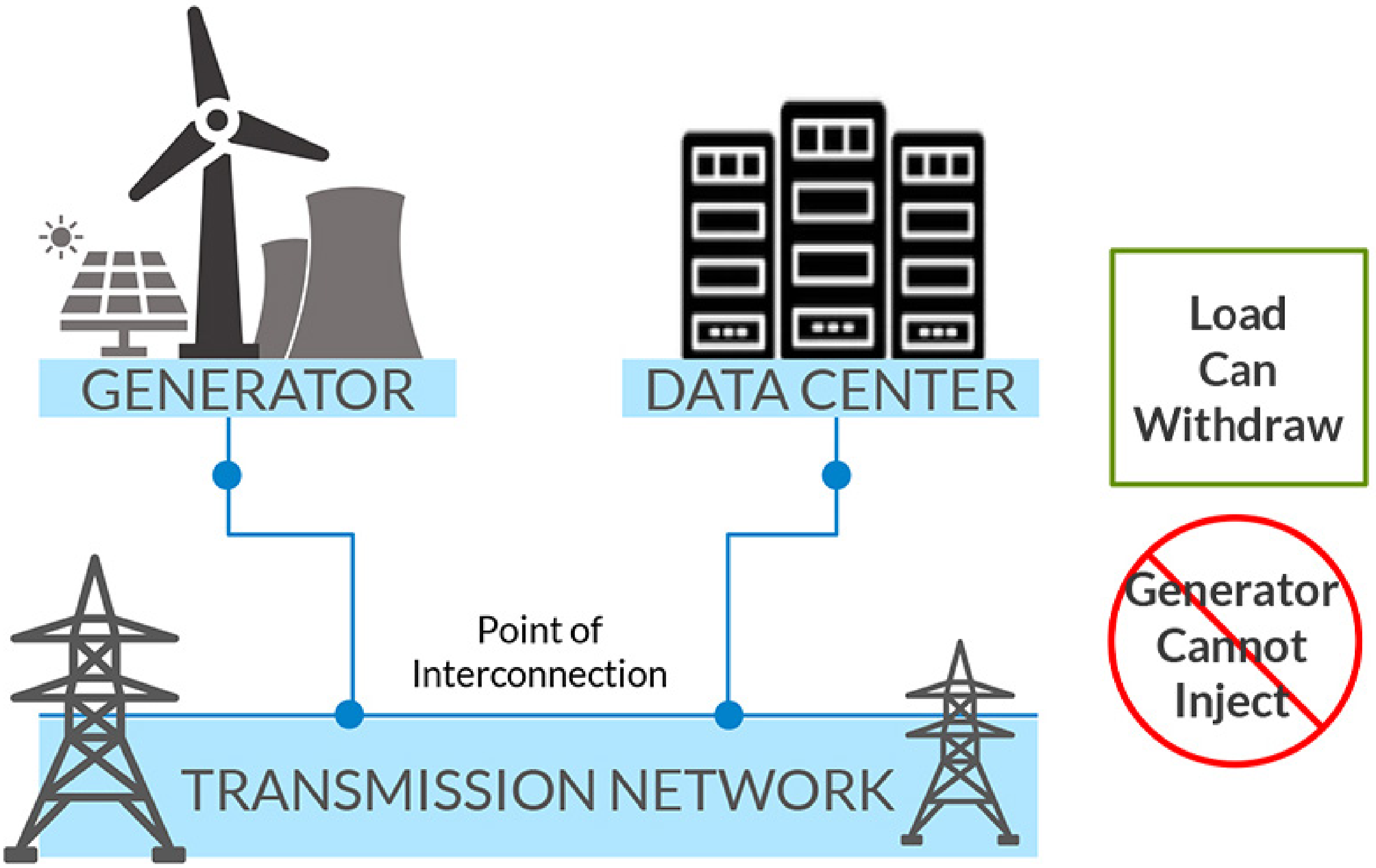
Keyser acknowledged that the new GIA type would have limits and said a generator that wants full rights on the MISO system would still have to submit to the full-length queue process.

“It’s certainly not a full solution. You have a generator that cannot inject when you come out of the end of this,” he said.

The idea is part of MISO’s larger push to create registration and market participation rules for co-located generation and load.

Why This Matters

MISO has suggested a new type of generator interconnection agreement — which wouldn’t allow energy injection onto its system — to get generation intended solely for large loads online faster.



A diagram illustrating how MISO’s “zero-injection” interconnection agreements would work | *MISO*

"As these configurations become more common, we want to make sure our frameworks evolve to serve them," MISO Director of Expansion Planning Jeanna Furnish said.

Keyser said the new type of GIA could work alongside MISO's other efforts to incorporate large loads, including its interconnection queue fast lane, its long-range transmission planning, its expedited transmission request process and its ongoing efforts to cut regular queue processing down from about four years to 373 days.

Furnish said MISO would focus on how it can better enable large load integration over 2026.

But stakeholders said implementing the new, limited GIAs might not be as simple as RTO staff made it seem.

WEC Energy Group's Chris Plante said stakeholders need time to "opine on the merits of such an arrangement." Plante said he wasn't sure MISO applying network status to generation barred from injection would square with FERC's rule against RTOs netting behind-the-meter generation with load.

"I'm not even sure that we know this is feasible from that standpoint," Plante said. "I'm very concerned that we've put something on the table that hasn't gone through a full stakeholder discussion."

Keyser said the proposal is in the early stages and that MISO doesn't intend to "create a netting situation between load and generation." He said the RTO would contemplate the loss of generation in its interconnection studies so as not to lump load and generation together.

He added that MISO has filed GIAs in the past with zero megawatts of injection service specified in them.

But Plante said MISO should examine what the generation would do without the load. He said if load trips and its dedicated generation does not, the generation would be injecting on the grid, "even if momentarily."

"Can we sustain the loss of a 1.2-GW data center?" Plante asked hypothetically.

The Sustainable FERC Project's Natalie McIntire asked MISO to stay focused on the technical details of the proposal, especially how curtailments of generation and load might be handled should either go offline unexpectedly.

"I want to make sure we don't forget the important technical questions," McIntire said.

American Transmission Co.'s Erik Winsand said MISO must decide on how it would conduct technical studies, as well as what tariff changes might be necessary to make zero-injection GIAs a reality.

MISO staff committed to refining their plan. Keyser asked stakeholders to bring opinions on whether the RTO should require a contractual link between load and generation or if the load and generation should be allowed to span electrically similar pricing nodes. He also asked for more advice on whether MISO should prepare for planning and reliability risks under the new GIAs.

Hoosier Energy's Tommy Roberts said the idea was "exceptional" and that the RTO should move quickly to implement it.

"We're going to get run over if we move slowly," he said.

However, Roberts said he was concerned that diagrams in MISO's presentation appeared to show two separate points of interconnection between the load and generation, instead of both behind a single point of interconnection.

"There is some level of injection just between two points on a switchyard out of data center," Roberts pointed out.

Keyser agreed that the chart MISO presented was flawed and said the intent is for both load and generation to be situated behind the same point of interconnection.

MISO is scheduled to discuss its proposal at a Planning Advisory Committee meeting Jan. 21, 2026, and again during a stakeholder workshop Jan. 30 dedicated to discussing the implications of large loads.

Keyser said MISO would move "rapidly" over 2026 to firm up the proposal. ■

NYISO Monitor Says More Data Needed to Verify Out-of-market Actions

By Vincent Gabrielle

The NYISO Market Monitoring Unit cannot *verify* the need for out-of-market actions on the part of transmission owners for reliability, it told the Installed Capacity Working Group on Dec. 1.

This is because the tariff does not specifically grant the MMU the power to obtain the data necessary to verify such actions, said Pallas LeeVanSchaick, vice president at Potomac Economics, the MMU.

LeeVanSchaick included the analysis as part of a presentation of the third-quarter State of the Market report in response to stakeholder questions on the first-quarter report in August. (See *NYISO Stakeholders Concerned About Lack of Data on Supplemental Commitments*.)

The MMU is unable to verify whether all day-ahead reliability units and supplemental resource evaluation calls are scheduled because of actual reliability needs. These out-of-market actions actually became less frequent in New York City because of new 138-kV transmission, but 23% of them could not be verified.

LeeVanSchaick said that while the NYISO tariff gives the MMU broad access to data from "market parties" and "sellers," TOs do not specifically qualify as either. This means the MMU is dependent on the data that TOs give to NYISO, which are frequently not detailed enough to verify reliability calls. He noted, however, that NYISO has begun to receive more detailed information on out-of-market commitments "in recent months."

Multiple stakeholders expressed concern that the Monitor had "their hands tied" trying to get data from TOs. A TO representative said they had a unique responsibility for local reliability and that this had to be taken into consideration should any new regulations be developed.

Stakeholders and the MMU seemed open to discussing the issue further at upcoming meetings, which may create calls for tariff changes to address information gaps.

State of the Market

All-in prices *ranged* from $62/MWh in the North Country to $100/MWh in New York City, up 36 to 50% from last year. LeeVanSchaick said that this was primarily driven by natural gas price increases of 42 to 66%.

National Grid's Northport Power Plant on Long Island | © RTO Insider

Additionally, NYISO became a net exporter of energy to Quebec for the first time in summer, averaging 480 MW. Canada's exports to the ISO fell 1.4 GW year-over-year. July's heat waves led load to peak at 30.6 GW, 6% higher than last year's.

Congestion revenues rose 35% year-over-year, caused by transmission outages in Western New York and New York City. Long Island lines accounted for the largest share of congestion statewide, particularly on high-load days in July.

Over the summer, the Monitor identified an average of 2.2 GW of forced outages on high-load days, far higher than the anticipated 1.6 GW of market outages. During the most extreme heat waves, additional capacity was unavailable in real time because of the inability of generators to ramp, ambient heat and ambient humidity. In total, these three factors removed 600 MW of capacity statewide. LeeVanSchaick said this "overstated significantly" the available capacity on the market.

Other Business

The ICAP Working Group also reviewed tariff revisions for the *Improved Duct-Firing Modeling* project and the NYISO/Hydro Quebec interconnection *agreement*.

It also *discussed* revisions to the aggregation manual for municipal electric utilities. NYISO staff said they believe a new section of the manual will need to be added to support the participation of distributed energy resources within municipal utility territories.

In addition, NYISO responded to stakeholder requests for information about how much generation had *elected* to be considered firm for the 2026/27 capability year. (See *NYISO Business Issues Committee OKs Firm Fuel Accreditation Concept*.)

In New York City, 7.6 GW of capacity elected as firm, representing 82% of capacity covered by the firm fuel option. On Long Island, 89% of capacity elected firm, totaling 4.6 GW. In the Capital District, which is the only area upstate modeled as being fuel constrained, 80% of eligible capacity totaling 2.8 GW elected firm. ■

PJM Stakeholders Endorse Manual Revisions for Modeling DERs

By Devin Leith-Yessian

The PJM Planning Committee on Dec. 2 endorsed by acclamation manual *revisions* to reflect how distributed energy resources would be accredited for participation in the 2028/29 Base Residual Auction in compliance with FERC Order 2222. The market-side rules were endorsed by the Market Implementation Committee in November. (See *PJM Stakeholders Endorse Rules for DER Participation*.)

The *changes* to Manual 20A: Resource Adequacy Analysis detail how components of DERs would be reflected in effective load-carrying capability modeling and the reserve requirement study, how hourly output would be simulated for each component technology class, and how accredited unforced capacity would be calculated for each resource. Class ratings would not be produced for DERs as a whole; instead, they would be calculated for each resource based on its composition.

The proposed Manual 21B: PJM Rules and Procedures for Determination of Generating Capability *language* includes the calculation of installed capacity and effective nameplate capacity values for each DER component and how backcasts of hourly performance would be produced. Aggregations including wind or solar components can substitute PJM's backcast with their own going back to June 1, 2012, with accompany documentation of the methodology and date used to produce it.

Planning Manual Revisions Endorsed

Stakeholders endorsed *revisions* to Manual 14B: PJM Region Transmission Planning Process drafted through its periodic review, including several administrative updates and a change to ambient ratings to conform with FERC Order 881.

When PJM is developing the light-load ambient ratings in the assumptions for the Regional Transmission Expansion Plan (RTEP), transmission owners would be permitted to choose either the default 59F thermal rating or 60F.

The RTEP Reliability Planning section was tweaked to add phase angle regulators when referencing phase shifting transformers to improve consistency between manuals and the new equipment energization process checklist. The section was updated with links to the relevant PJM departments.

First Read on Manual Revisions Expanding Dual-fuel Definition

PJM *presented* a first read on revisions to Manual 21B to reflect FERC-approved changes to the definition of dual-fuel gas generation to include configurations where the secondary fuel is stored off site but connected to the generator with a dedicated firm pipeline (*ER25-3413*). (See "Reworked Dual-fuel Definition Endorsed," *PJM MRC/MC Briefs: July 23, 2025*.)

When first introducing changes to the governing documents in June, Dominion said resources with a dedicated connection to secondary fuels can provide a comparable level of reliability as those where the fuel is stored on site. (See "Dominion Presents Proposal to Change Dual-fuel Definition," *PJM MRC/MC Briefs: June. 18, 2025*.) ■

Colonial Pipeline

PJM MIC Tackles Issue Charges, Problem Statements

By Devin Leith-Yessian

Brian Chmielewski, PJM | © *RTO Insider*

PJM *presented* a quick fix proposal Dec. 3 to address instances in which offline generators are committed as secondary reserves and granted lost opportunity cost (LOC) credits, despite governing document language stating resources not synchronized have zero LOC. The quick fix pathway allows for an *issue charge* to be brought concurrent with a proposed solution.

The issue charge focuses on instances in which a resource that is offline when it is dispatched as secondary reserves comes online before that commitment begins. According to the problem statement, real-time security constrained economic dispatch (RT SCED) commits resources 10 minutes before each interval, but settlement is focused on revenue quality meter data when the commitment begins. If the resource begins injecting energy before the interval begins, it would appear as being online and eligible for LOC credits by the settlement calculations.

The proposal would use resources' output at the time they are committed by RT SCED to determine if they are offline and, if so, set the real-time secondary reserve opportunity cost at zero.

1st Read on Flexible Resource Definition Clarification Issue Charge

PJM presented a first read on a *problem statement* and *issue charge* to reconsider how a resource is defined as flexible and eligible for LOC credits when committed in the day-ahead energy market on an offer with flexible parameters, but could be dispatched on schedules that are not flexible in real time. Under such circumstances, intermediate term (IT) SCED may not be able to determine whether the resource is economic and dispatch it.

The problem statement gave an example of a resource with a flexible cost-based schedule and an inflexible price-based schedule, which is committed on the former in the day-ahead market due to it failing the three pivotal supplier test when a transmission constraint is modeled. If that constraint does not materialize, IT SCED would revert to the price-based offer but be unable to evaluate whether it is economic due to the difference in the parameter flexibility. The resource would not be committed and would receive LOC credits for the duration of its day-ahead commitment on the cost-based offer schedule.

"Opportunities exist to consider whether a resource should be considered flexible for commitment and lost opportunity cost purposes if there are differences in startup time, notification time and min run time parameters amongst the available schedules," the problem statement reads.

PJM's Susan Kenney said the issue charge would explore whether the parameters in each of a resource's offers should be reviewed before it is considered eligible for LOC credits.

Stakeholders argued there may be a deeper issue with the dispatching software if economic resources able to operate are not being dispatched.

PJM's Brian Chmielewski said the issue is that regardless of whether a unit committed on a flexible schedule in the day-ahead run is economic, real-time dispatching is limited to evaluating all offers based on those flexible parameters.

The issue charge includes education on the definition of flexible resources, how they are committed and when a unit is eligible for LOC credits. It envisions changes to the RTO's governing documents and manuals addressing LOC eligibility for flexible resources, with work expected to take around three months starting in January 2026. Changes to how IT SCED selects schedules would be out of scope.

Fuel Cost Policy Issue Charge

PJM and the Independent Market Monitor brought an *issue charge* seeking to address the potential for market sellers to inflate cost-based offers by acquiring fuel cost estimates from an affiliated supplier.

"There may be inherent incentives for a fuel supplier to provide a fuel cost estimate to an affiliated market seller or designated agent of such market seller that may not be reflective of the expected fuel cost or the market price. Such an outcome could be used by market sellers that have market power (e.g., fail the three pivotal supplier test) to potentially manipulate the market by obtaining a fuel cost estimate from an affiliated fuel supplier that may not reflect market pricing of fuel costs. Such an approach would allow market sellers to set energy prices at an uncompetitive level," the *problem statement* reads.

The issue charge scope is limited to how fuel cost policies reflect affiliated suppliers of fuel versus independent third parties, while broader changes to the policies would be out of scope. ■

PJM Operating Committee Briefs

November Operating Metrics

PJM's forecasting of hourly peak loads continued to improve in November, with an error rate of just 1.17%, lead engineer Marcus Smith *told* the RTO's Operating Committee on Dec. 4.

And while the 1.31% error rate for hourly forecasts was higher than October, it remained below the two-year average, Smith said.

He said forecasts held up Nov. 11, when Veterans Day coincided with the lowest temperatures of the month, while Thanksgiving was also the coldest observed since 2018. Holiday load forecasts have taken on pronounced importance since December 2022's Winter Storm Elliott, when gas generators struggled to determine whether they should nominate for fuel packages spanning the long weekend. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

Nov. 20 was the only day with a peak error rate exceeding the RTO's 3% error benchmark, with cooler weather pushing the peak load to 3.15% higher than forecast.

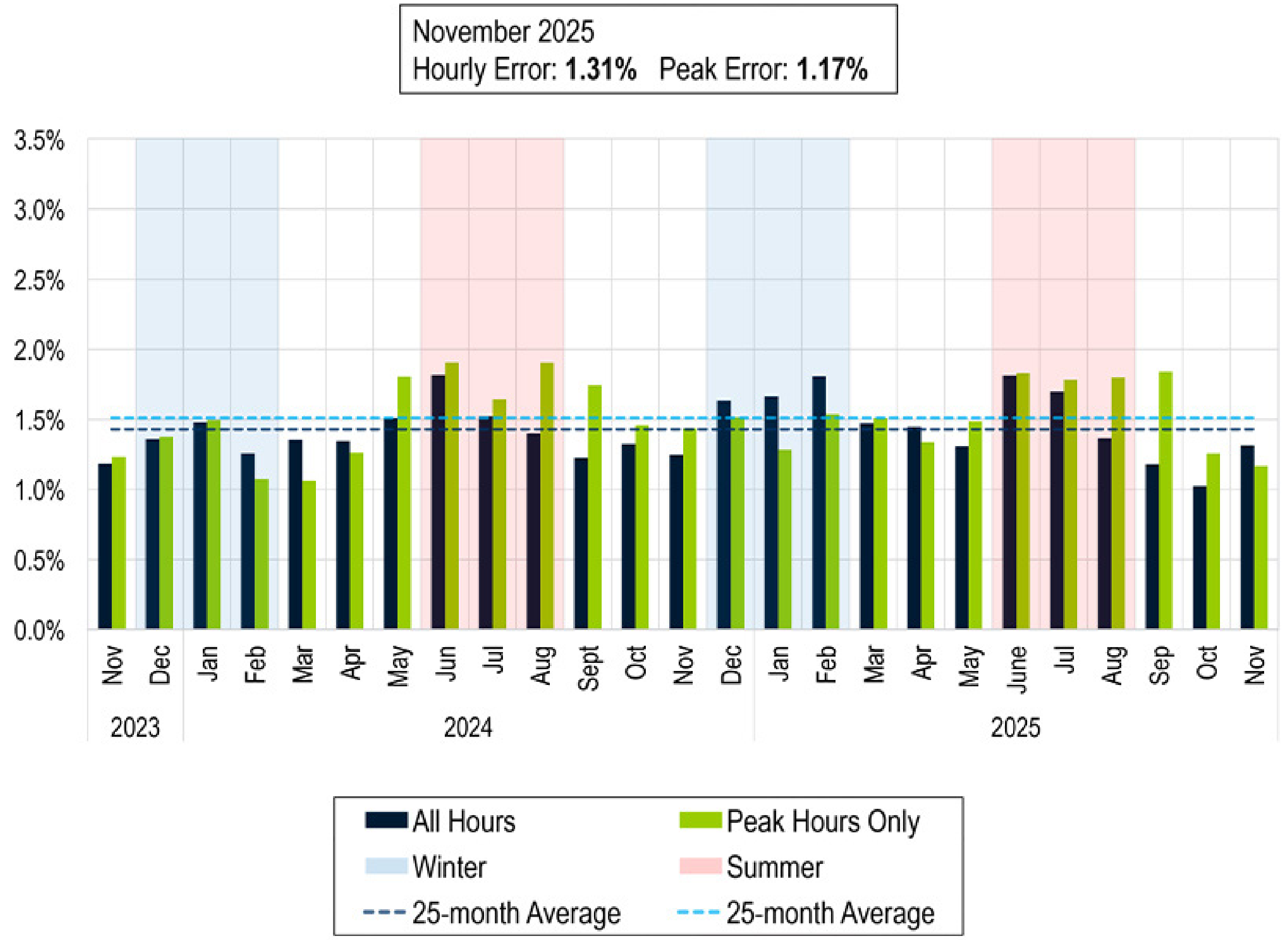
There were three spin events, three shared reserve events, two geomagnetic disturbance warnings, 13 shortage cases and 14 post contingency local load relief warnings in the month.

Eight of the shortage cases were declared on the morning of Nov. 18, leading stakeholders to question whether solar ramping was a factor. PJM's David Kimmel said there have been a higher number of shortage cases related to solar over the past few months, but staff are still investigating the drivers on that day.

One shortage case was issued Nov. 16 and four the following day, which were attributed to software issues.

A Nov. 11 spin event lasted 10 minutes and 17 seconds, meeting PJM's threshold for including it in a three-event rotating average being tracked for determining whether the RTO should back down a 30% adder on the synchronized and primary reserve requirement implemented in May 2023.

The RTO assigned 2,051 MW of generation, of which 80% responded, and 673 MW of demand response, with a 91% response. If performance across three events longer than 10 minutes exceeds 75%, the adder will be reduced by 10%,



PJM presented the peak and hourly load forecast error for November. | *PJM* with the possibility of it being further reduced if performance is higher than 85 or 95%. (See *PJM OC Briefs: March 6, 2025*.)

Monitor Presents Synchronized Reserve Performance Inquiry

The Independent Market Monitor *updated* the results of its ongoing inquiry into the contributors to low synchronized reserve performance, which has involved reaching out to resource owners whose units under- or overperformed their commitments during deployments exceeding 10 minutes.

The Monitor first presented its findings during the OC meeting Nov. 3. (See *PJM Monitor Presents Spin Event Performance*.)

Communications issues have become less of a factor since the first event the Monitor investigated July 8, 2024; however, inadequate training and incorrect parameters continue to be issues, it said.

Incorrect parameters were the largest cause of shortfalls during an Oct. 17 spin event, which saw 2,336 MW assigned with a response rate of 81%. The second largest cause was modeling issues, with the remaining contributors having too few respondents to be reportable because of confidentiality rules.

An Oct. 28 event saw 2,015 MW assigned and 69% responding, with software and hardware issues being the main driver, followed by incorrect parameters.

The Monitor recommended that PJM revise its reserve performance metrics by including all assigned reserves and recognizing overperformance in the calculation. Doing so would increase performance during the Oct. 17 event to 100% and result in 81% performance on Oct. 28.

PJM Seeks Quick Fix on Data Communications

PJM *presented* a quick fix to revise Manual 1: Control Center and Data Exchange Requirements seeking to add clarity around how the RTO and members share information.

Language was added to reflect NERC's reliability standard *CIP-012-2* (Cybersecurity – communications between control centers), which requires entities to have plans to "mitigate the risks posed by unauthorized disclosure, unauthorized modification and loss of availability of real-time assessment and real-time monitoring data in transit between applicable control centers." It details the RTO's PJMNet system for internal communications.

The section detailing the RTO's Energy Management System (EMS) would be revised to require members submitting distributed network protocol links to provide data maps and definitions. The language includes a statement that PJM will not consume or process data not required for its own purposes.

"This policy additionally ensures fair and balanced benefits of PJM [supervisory control and data acquisition] and networking resources, and ensures that PJM does not prematurely surpass inherent data size limits of the EMS," the manual language reads. ■

— Devin Leith-Yessian

FERC Approves SPP Process for Incremental Capacity

Commission Rejects 2 Related Tariff Revisions, OKs ESR Assessment

By Tom Kleckner

FERC has approved an SPP tariff revision designed to accelerate the addition of new generation by quickly adding shovel-ready incremental capacity — up to 20% of the facility's "maximum injection capability" — at existing generating sites.

The commission said in its Nov. 28 order that SPP's temporary priority process "makes efficient use of the existing transmission system" by queuing eligible generator interconnection requests higher than existing study clusters that haven't started. It said the proposed accelerated time frame, not subject to waiting for open seasons or processing as part of a cluster or from needs driven by other requests, ensures customers can interconnect in a "reliable, efficient, transparent and timely manner" (*ER25-3570*).

The priority process meets FERC's "independent entity variation standard" and its Orders 2003 and 2023-A. The process was accepted Nov. 28, became effective Dec. 1 and will be in place until March 1, 2026. That's when SPP's Consolidated Planning Process, assuming FERC approves it, is to take effect. The CPP, an integrated, three-year transmission planning cycle blended with generator interconnection studies, is planned to produce its first assessment in 2028. (See *SPP Celebrates Novel Consolidated Planning Process*.)

But the commission rejected two other tariff revisions by SPP: its proposals to expand eligibility for the priority process to generators retired for less than five years (*ER26-153*) and to modify the queue's priority for interconnection and priority requests (*ER26-156*).

FERC ruled the priority request process enables SPP to meet "projected near-term resource adequacy needs more quickly" than would its existing study cluster process. It agreed with the RTO's contention that the commission has "recognized the benefits of improved queue efficiency."

"The priority process will improve the efficient interconnection of new generating facility capacity by allowing incremental additions to existing generating facilities to come online in an expedited manner without impacting existing interconnection customers," FERC said, quoting its own statements.

> **Why This Matters**
>
> SPP told FERC its current generator interconnection process "may be unable to meet the near-term resource adequacy needs" of its load-responsible entities that are "subject to a set of heightened eligibility and financial-readiness requirements."

The grid operator told the commission its current GI process "may be unable to meet the near-term resource adequacy needs" of its load-responsible entities that are "subject to a set of heightened eligibility and financial-readiness requirements."

FERC in August approved separate planning reserve margins for the 2026 summer and winter seasons that LREs must meet; those that fall short could incur deficiency payments. The approval set a 36% PRM for the winter season and a 16% margin for the summer. (See *FERC Approves SPP's Separate Winter, Summer PRMs*.)

The commission found the priority process is "narrowly tailored" to address the RTO's near-term resource adequacy or reliability needs because it applies only to existing facilities — and just once — and because the eligibility and financial commitment requirements "prevent speculative interconnection requests," reducing the potential for time-consuming restudies.

Priority project owners must cover all costs of the priority system impact studies and all necessary substation network and system network upgrades.

FERC said the heightened eligibility and financial readiness criteria limit an interconnection customer's ability to qualify for the one-time study. "These limits allow only ready projects that do not impact existing interconnection customers" to use the priority process, it said.

In rejecting SPP's two related tariff revision proposals, the commission said the grid operator lacked details for allowing retired generators to take advantage of the priority process. It pointed to lack of clarity over whether the project could be 120% of the size of the retired generator or 20% of its size.

New ESR Load Assessment

FERC also accepted SPP's tariff revisions that outline the study requirements for load assessments of electric storage resources (ESRs) subject to the RTO's generator-interconnection procedures, effective Oct. 7, 2025 (*ER25-3105*).

The commission found that because SPP's revisions incorporated FERC's *pro forma* LGIP language from Orders 2023 and 2023-A, they were deemed just and reasonable and not unduly discriminatory or preferential. It said the deviations from the commission's *pro forma* LGIP and LGIA accomplished the purposes of Orders 845 and 2023.

FERC said SPP's proposal to define a new term in its tariff — ESR-LA, for ESR load assessment — to evaluate the effects of an ESR withdrawing energy from the transmission system, in accordance with NERC Reliability Standards, will help facilitate the reliable interconnection of new ESRs.

"SPP's proposed revisions specify that SPP will study an electric storage resource only under off-peak conditions and then assess whether any charging limitations must be imposed on that resource," the commissioners wrote. "Studying the resources under off-peak conditions is based on the resource's expected real-time charging behavior, and any charging limitations will be based on the available capacity of the transmission system."

The RTO's proposal will apply to those interconnection requests submitted in the 2024 study cluster window. ■

BPA Outlines Next Steps in Markets+ Implementation

Questions Persist About Seams, Timeline

By Henrik Nilsson

As the Bonneville Power Administration prepares to join Markets+, the agency hopes to complete the initial program governance setup and define its commercial model for market participation early next year, though questions persist about the timeline and market seams.

BPA provided the update during a Dec. 4 day-ahead market participation workshop. BPA committed to SPP's Markets+ in May, and the power agency is to begin participating in the day-ahead market in October 2028. (See *BPA Chooses Markets+ over EDAM*.)

But several key steps remain, according to Nita Zimmerman, acting vice president of bulk marketing at BPA.

"The policy direction is to pursue Markets+, but several important steps still remain, which include a rate case, a tariff proceeding, a National Environmental Policy Act analysis and the successful negotiation of a Markets+ implementation agreement," Zimmerman said.

Another step includes defining BPA's commercial model framework. While the network model deals with physical elements, such as electrical nodes, metering and transmission elements, the commercial model connects those physical elements to the financials, explained Sara Eaton, senior analyst at BPA.

"The commercial model is creating that mapping between the network model, the physical and then the financial," Eaton said. "So, when we say 'commercial model,' it's going to have settlements impacts, and that's why it's really important to get it right and to start those conversations early."

Why This Matters

Though BPA has committed to SPP's Markets+, many steps remain before the agency can fully join the market in October 2028.

To define the commercial model, BPA must answer questions about how entities interact in the market, how resources and loads are modeled, and how information is shared among market participants, said Libby Kirby, BPA's Markets+ program manager.

"A lot of those framework questions drive all of the downstream work that ends up happening," Kirby said.

"So, once we have gotten some of those commercial model framework questions answered, we will move into some of those more formal work streams — developing software, developing processes, etc. — as well as getting into our internal testing," Kirby said.

According to BPA's presentation slides, the agency aims to complete the initial governance program setup by March 17, and the commercial model by March 31, 2026.

Other preparations include aligning the agency's provider-of-choice contracts with Markets+ and preparing the exit from the Western Energy Imbalance Market.

Another issue is the market seams expected to arise from the split between Markets+ and CAISO's Extended Day-Ahead Market. (See *SPP Markets+ Cruising Through Early Development*.)

Steve Greenleaf, senior director of regulatory affairs and policy at Brookfield Renewable, asked whether BPA plans future workshops on seams or if those concerns are limited to SPP.

Kirby responded that BPA does not view seams as an "SPP-only issue."

"I think we all have a stake in the outcome, and so I don't think we expect to just say, 'Yep, [SPP is] going to do it all, and we have no interest in that,'" Kirby said. "I think we have lots of interest and probably some opinions that we'd like to share with them."

She noted SPP plans to host a symposium on seams in February.

"I don't know that there's an explicit full road map … yet that sort of bridges both sides, but I think that is something that [SPP is] considering, and that we very much know that we will continue to poke at," Kirby said.

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

'Weakest Link'

Henry Tilghman, a consultant with the Northwest & Intermountain Power Producers Coalition, questioned whether BPA can keep its Markets+ implementation timeline, given that certain upgrades are still pending.

"The reason I'm asking is a chain is only as strong as its weakest link, and the [Automatic Generation Control] upgrade has been pending for at least a year and a half," Tilghman said. "And for some reason, I still can't get a timeline for when that's going to be completed."

"What is your confidence level in delivering on the schedule given that there is a very important software upgrade that doesn't have any timeline to complete, as near as I can tell," Tilghman said.

Kirby described her confidence level as "decent."

"I think it's too early to be too confident. It's too early to be too pessimistic," Kirby said. "Right now, we are making plans to meet it. Right now, we think we can meet it, including with AGC. But I think obviously there are risks. There are risks for workload; there are risks if we go live and [market participants] aren't ready, what do we do? We have to have contingency plans. We have to have backup plans. I think that is all part of the conversation right now." ■

REAL Team Endorses DR Policy, CONE Value

By Tom Kleckner

DENVER — The SPP leadership team responsible for strengthening the grid operator's resource adequacy construct and recommending policy directions closed out 2025 by endorsing two protocol changes related to demand response and the cost of new entry.

Meeting Dec. 3 during Denver's first snowfall of the season, the Resource Energy and Adequacy Leadership (REAL) Team approved combined policies for demand response and load-responsible entity peak demand assessments and the value of the cost of new energy for 2026, representing the cost to build a new power plant.

The CONE value, increased to $139.85/kW-year for summer 2026, passed unanimously. However, the REAL Team split 7-5 over the DR and peak demand assessments (*RR703*), emblematic of the difficulty SPP has had in developing a demand response policy since 2017.

"Everyone knows that SPP has been in increasing complex and challenging issues all the time, and here we are again," REAL Chair Kristie Fiegen, with South Dakota's Public Utilities Commission, said after the vote. "The stakeholders have worked very, very hard on this. We have listened to a lot of comments the last six months, and we've made a lot of changes. Is it perfect? No.

"So, it may not be perfect today, but we can always come back to it, because we will continue to monitor and adjust this in the future."

"We're at a point where staff has considered input from a bunch of different stakeholders … It's gotten us to a point where I think at least staff is comfortable and [can] support the policy, but it's not ever going to be ideal," said Natasha Henderson, SPP's senior director of grid asset utilization. "I think the policy that we have before us does an adequate job of balancing that as we walk forward. We are going to learn and check and adjust."

Henderson said the policy has reached the point where "hopefully, people can agree that it's just and reasonable" and that it balances the affordability and reliability equation at the forefront of the utility industry.

SPP says demand response is "increasingly critical" as it looks at a future with rapid load growth, evolving resource mixes and tighter energy conditions.

Carrie Bivens, with the MMU's John Luallen, explains the Monitor's opposition to the demand response and LRE peak demand assessment. | © *RTO Insider*

DR supports reliability, stabilizes prices during uncertainty and helps the region adapt to changing system dynamics, it said.

Staff said a structured DR policy provides entities with multiple participation pathways and market, reliability and potential load-modifying products. It will also help defer the cost of new generation and supporting resource adequacy compliance.

The intent is to increase the visibility and ability to deploy demand response by creating a participation model and accreditation framework for non-price-sensitive DR. SPP seeks to incent LREs to manage peak loads by qualifying non-registered or load-modifying demand response capable of performing when their peak loads exceed their qualified resources.

The assessment will require LREs to use qualified resources to meet demand when accounting for the risk considered in the loss-of-load expectation study that sets the planning reserve margin requirements. That will mean an accurate 50-50 forecast and not one that incorporates all risks.

The peak demand assessment (PDA) is a CONE-based evaluation performed after a weather season based on the variation of actual load from the entity's load forecast.

The measure was opposed by Evergy's Denise Buffington, Oklahoma Corporation Commission staffer Jason Chaplin, the Advanced Power Alliance's Steve Gaw, Oklahoma Municipal Power Authority's Dave Osburn and American Electric Power's Richard Ross.

Ross proposed what he called a post-season review to identify the LREs with the largest underforecast amount, requiring them to explain their error in a report that would be delivered to the board's Oversight Committee. He referred to the review as casting sunshine on any chronic forecasting problems and force members to "sharpen their pencils."

"I think ours is pretty sharp as it is, but we can do more," Ross said. "Some folks make fun of my cute little phrases, but the framework would be much like SPP is going to do already."

"I can't help but point out the irony of Richard's 'sunny day' proposal when it's snowing," Henderson said, gesturing to the falling snowflakes outside.

She reminded the REAL Team that SPP's tariff requires that a post-season analysis be conducted and a report published. Henderson said the report reviews every LRE and is then discussed by the Supply Adequacy Working Group.

Carrie Bivens, vice president of SPP's Market Monitoring Unit, said the Monitor still had some outstanding issues with the proposed changes, despite its engagement with RTO staff. She called for clarity around dual participation to "clearly prohibit" loads that are already in a retail program from participating in DR but saved the bulk of her comments for the LREs' peak demand assessment.

"This is a significant one for us," Bivens said.

She said the MMU supports the policy's key objective of efficiently deploying load-modifying resources to manage peak loads and could support a PDA to accomplish this if it assesses deficiencies based on actual load but does not support the current framework.

"If we continue down the path … we think that the deficiencies need to be based on actual load, and that would mean no error tolerance and no weather normalization," she said. "We do think that this framework, the way it is proposed, actually maintains the RA incentive structure. We just think this policy inappropriately socializes risk to the members."

In response, Henderson said SPP has already opened three DR-related strategic initiative requests (*SIRs 812, 814 and 816*) to tackle the MMU's concerns. The grid operator uses SIRs as part of its strategic road map to meet its long-term goals.

CONE Value Changed

The REAL Team endorsed the CONE's value — setting it at $139.85/kW-year, up from the current $85.61/kW-year — but did not vote on any changes to the calculation's process.

SPP bifurcated the proposed tariff change (*RR729*) following feedback from the REAL Team, the Supply Adequacy Working Group and other stakeholders. Staff said a new revision request will be introduced to address broader process changes, allowing additional time for stakeholder feedback and further development of the inputs and assumptions used to recalculate the CONE's value.

The grid operator sets its CONE value annually by Nov. 1. Resource adequacy staff adjust the value for inflation and update tax rates and interest rates. It uses U.S. Energy Information Administration data for a generic generator in a region without any special considerations for altering cost as part of the calculation.

The REAL Team unanimously endorsed the measure, with committee Chair Buffington abstaining.

The Board and Directors and Regional State Committee must both approve the CONE value change.

Fall Alert Hours Drop in 2025

SPP staff told the REAL Team that operations alerts and advisories, which have increased over the past three fall seasons, resulted in only 45 alert hours this year. In October 2024, the grid operator issued a conservative operations advisory and went through 194 alert hours.

Staff said mild September weather and fewer resource outages in late October led to the decrease.

More than 26 GW of outages were recorded in mid-October, consistent with outage trends during the shoulder months in the last three years. By early November, outages were tracking as much as 4 GW below the five-year norm.

Still, the grid operator issued its first resource advisory of the winter Nov. 29 for the entire balancing authority because of expected high peak loads, wind forecast uncertainty, severe cold weather and potential for above-normal generation outages.

SPP treats resource advisories to be normal operating conditions, two steps away from a Level 1 energy emergency alert. Resource advisories are issued to raise awareness in the market and don't require conservation measures.

The RTO issued seven resource advisories and three conservative operations advisories — the last step before an EEA — during the summer. Staff issued 11 resource advisories during the summer of 2024 and three calls for conservative operations.

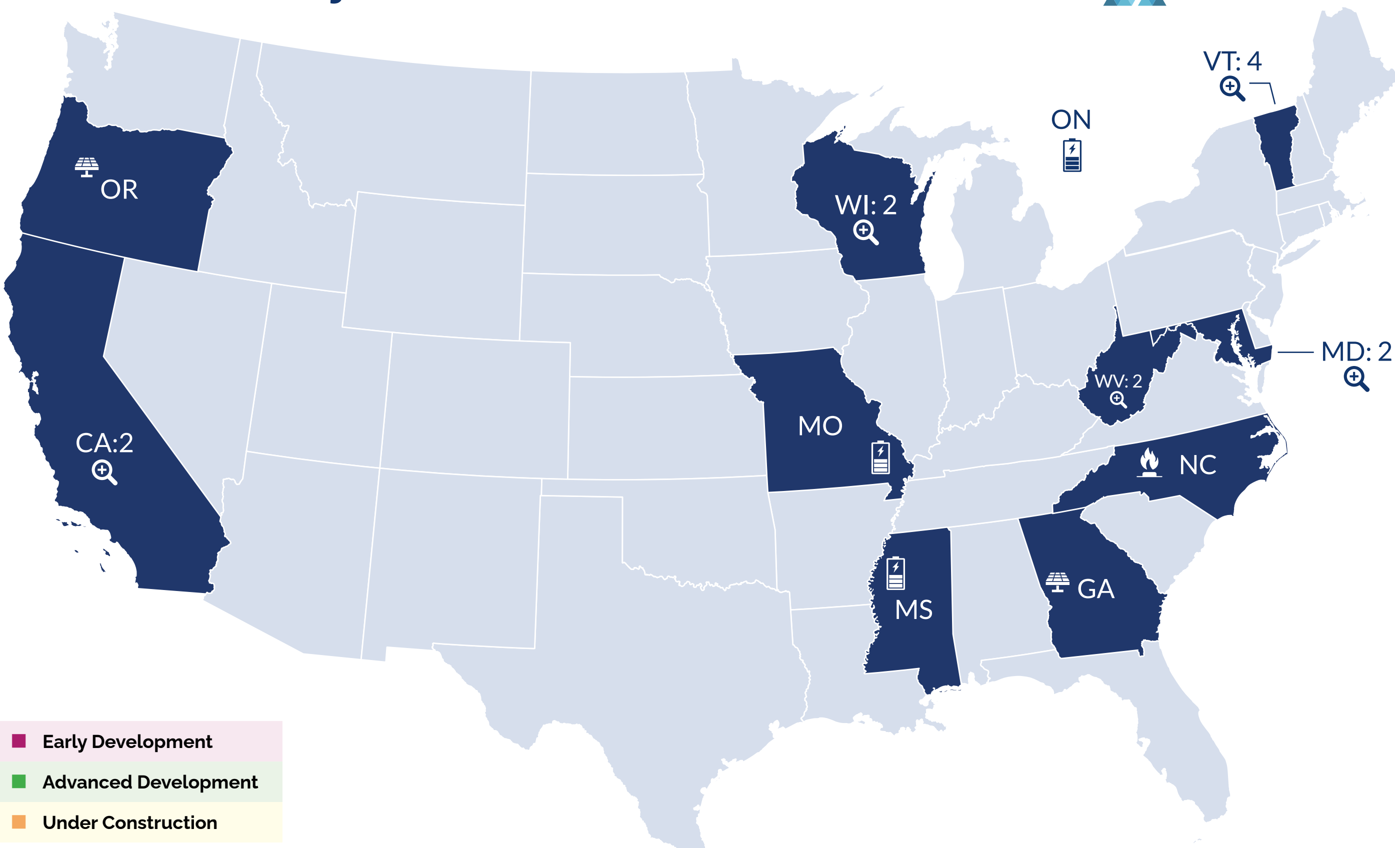
New Leadership to Meet

The REAL Team meeting was the last for Fiegen, who has chaired the group since its inception in 2023.

Chuck Hutchison, a member of the Nebraska Power Review Board, will succeed Fiegen as chair in 2026. He said he and SPP Board Chair Ray Hepper and SPP's Henderson and Casey Cathey will meet to discuss the REAL Team's work plan for next year. ■

Generation Projects Added in the Past Week

YES ENERGY



Early Development
Advanced Development
Under Construction

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

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Grape Solar BESS	Westside Holdings, LLC	Westlands Solar Park	CA	150	2027
	Gaskell West 1 BESS	Southern Company	Southern Power	CA	22	2026
	Kia Canopy Solar	Kia		GA	10	2026
	Denton Pine Solar	Summit Ridge Energy		MD	5	2027
	Hayford Solar	Chaberton Energy Inc		MD	4	2028
	Delta Bobcat Energy Storage	NextEra Energy, Inc.	ESI Energy	MO	160	2029
	Greer Energy Storage	NextEra Energy, Inc.	ESI Energy	MS	200	2031
	Buck Energy Complex	Duke Energy Corp	Duke Energy Carolinas, LLC	NC	850	2035
	Gateway BESS (ON)	EDO Group	EDP Renewables Canada	ON	200	2031
	Cartwright Solar II	Newsun Energy		OR	16	2026
	Borderland Solar	MHG Solar		VT	5	2029
	Little Brook Solar	MHG Solar		VT	3	2026
	Savage Solar Energy	MHG Solar		VT	3	2027
	Hi Lo Biddy Storage	Encore Renewable Energy		VT	5	2027
	Ten Mile Creek Storage	Xcel Energy	Northern States Power Co	WI	300	2032
	Butler Ridge Repower	NextEra Energy, Inc.	ESI Energy	WI	68	2028
	Mammoth Solar	Goldman Sachs Group Inc	MN8 Energy	WV	90	2029
	Mammoth Storage	Goldman Sachs Group Inc	MN8 Energy	WV	90	2029

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

Company Briefs

Amazon Backs out of Project Blue Data Centers

Amazon Web Services has pulled out of its role as future operator of the Project Blue data center complex in the Tucson, Ariz., area, according to sources.

Amazon has left the project because its operations aren't compatible with the project's recently announced plans to use air cooling instead of water cooling for the data centers' servers, the sources said. Beale Infrastructure, the project's developer, is now negotiating with Meta to replace Amazon as the center's operator.

Project Blue switched to plans for an air-cooled operation after the Tucson City Council voted unanimously to kill its effort to be annexed into the city and to receive city water supplies for its operations.

More: *Tucson.com*

Exxon Halts Plans for Low-carbon Hydrogen Facility

ExxonMobil has pulled the plug on what would have been one of the world's largest hydrogen plants after its $332 million grant from the Biden administration was taken away by the Trump administration.

In 2022, Exxon announced plans to build a facility at its refining and petrochemical complex in Baytown, Texas, with the capacity to produce 1 Bcfd of blue hydrogen, which is made using natural gas and carbon-capture equipment.

Since blue hydrogen typically costs about one-third more than the "gray" version of the fuel made with unmitigated gas, Exxon CEO Darren Woods said the company could not find enough buyers willing to pay the premium.

More: *Canary Media*

Eurowind Energy Exits 400-MW Battery Project

Danish renewables developer Eurowind Energy last week announced the sale of a 400-MW battery storage project in California under a plan that will provide it with cash for its European activities.

The divestment is in the Potentia-Viridi battery energy storage system project, which Eurowind Energy developed under a 50/50 joint venture with Capstone Infrastructure.

The project is expected to come online in June 2028.

More: *Renewables Now*

Federal Briefs

BOEM to Consider Revoking New England Wind 1 Approval

The Bureau of Ocean Energy Management last week filed a request with a federal judge asking to allow it to reconsider a key approval for New England Wind 1 project planned off the Massachusetts coast.

The filing comes more than two months after the government signaled it would take such action against the project.

It is at least the third time the administration has sought a remand of an offshore wind project approval, the others being for SouthCoast Wind and US Wind. The permits give major infrastructure projects the certainty to secure financing and move forward with construction.

More: *The New Bedford Light*

TVA Wins $400M Grant for Next-gen SMR

The Department of Energy last week awarded the Tennessee Valley Authority a $400 million grant for the development of the GE Hitachi BWRX-300 reactor.

Gen III+ reactors are advanced light water reactors that incorporate newer safety features and higher performance capabilities.

The grant was established by Congress in 2024.

More: *Knoxville News Sentinel*

Trump Admin Renames National Renewable Energy Lab

In a press release published Dec. 1, the Department of Energy has renamed the National Renewable Energy Laboratory the National Laboratory of the Rockies, effective immediately.

DOE said the renaming "reflects the department's renewed focus on 'energy addition,' rather than the prioritization of specific energy resources."

The laboratory was created in 1977 as a response to the 1973 energy crisis and has focused on the development and commercialization of a wide range of technologies, including photovoltaic cells, energy-efficient windows and hydrogen fuel cells.

More: *CPR News*; *Inside Climate News*; *National Laboratory of the Rockies*

National/Federal news from our other channels

DOE Awards Holtec, TVA $800M to Build Pioneering SMRs

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

State Briefs

ALABAMA

Alabama Power Moves Ahead with 2-year Rate Freeze

Alabama Power last week announced that all components of the company's regulated retail rates are not scheduled to increase through 2027.

Alabama Power said it will hold in place all existing factors in customer rates, including delaying until 2028 the implementation of previously approved adjustments for the Lindsay Hill generation facility.

The move comes a year after the company projected a nearly 2% rate reduction for 2025.

More: *Alabama.com*

COLORADO

PUC Mandates Emissions Cuts for Gas Utilities

The Public Utilities Commission voted 2-1 for investor-owned gas utilities to cut carbon pollution by 41% from 2015 levels by 2035.

The target — which builds on goals already set for 2025 and 2030 — is more consistent with the state's aim to decarbonize by 2050 than the other proposals considered. Commissioners rejected the 22 to 30% cut utilities asked for and the 31% target state agencies recommended.

If utilities hit the 2035 mandate, they will avoid an estimated 45.5 million metric tons of greenhouse gases over the next decade, according to the state's Energy Office and the Department of Public Health and Environment.

More: *Canary Media*

IOWA

UC Approves Tx Lines to Power Data Centers

The Utilities Commission last week approved a $221 million high-voltage transmission line project that will help power two large data center developments under construction in Cedar Rapids.

The order will allow ITC Midwest to build a 61-mile, 345-kV transmission line and rebuild another 34-mile, 161-kV transmission line. The project is key to providing power to two new, large energy users in Cedar Rapids' Big Cedar Industrial Park.

More: *Des Moines Register*

NORTH DAKOTA

Judge Finds Carbon Dioxide Storage Law Unconstitutional

Northeast Judicial District Judge Anthony Swain Benson last week sided with a landowner group and found a state law related to underground storage of carbon dioxide to be unconstitutional.

The Northwest Landowners Association sued North Dakota and the Industrial Commission in 2023, challenging a law that requires landowners to allow carbon dioxide storage beneath their property if at least 60% of the affected landowners agree to the project.

Benson wrote in his order that the state law is unconstitutional because it allows a government-authorized taking of property without an avenue for "just" compensation determined by a jury. In this case, the property is pore space — cavities in underground rock formations where emissions can be trapped.

More: *North Dakota Monitor*

PENNSYLVANIA

PUC Slashes Columbia Gas Rate Hike

The Public Utility Commission last week reduced a Columbia Gas rate increase.

Columbia Gas looked to raise the residential customer charge from $17.25 to $31.97/month. The PUC approved a charge of $23/month.

The new rates will take effect on or after Jan. 1.

More: *WHTM*

UTAH

Rocky Mountain Power Requests Rate Increase to Feed Fire Fund

Rocky Mountain Power last week filed a request with the Public Service Commission seeking a 4.48% rate increase for all customers.

The company's request stems from a law the state passed in 2024, which allowed utilities to establish a restricted fire fund fed by a surcharge to ratepayers. With the increase, the company is hoping to collect about $109 million a year, and eventually, after 10 years, about $1 billion.

The increase would translate to about $3.70/month for the average residential customer.

More: *Utah News Dispatch*

WASHINGTON

Gov. Ferguson Approves Large-scale Solar Farm

Gov. Bob Ferguson last week notified the Energy Facility Site Evaluation Council that he approved the 1,300-acre Carriger Solar project.

The 160-MW project will also have 63 MW of battery storage and will tie into the Bonneville Power Administration transmission system.

More: *Washington State Standard*

WISCONSIN

PSC Approves Utilities' Renewables Purchases

The Public Service Commission approved three utilities' plans to purchase four new renewable energy projects.

The purchases include the Saratoga Solar Energy Center, the Ursa Solar Park, the Badger Hollow Wind Farm and the Whitetail Wind Farm. The projects all had previous approvals from the PSC. We Energies will own 80% of each project, while Wisconsin Public Service and Madison Gas and Electric will each own 10%.

The projects will cost $1.48 billion and are expected to come online in 2027 and 2028.

More: *Wisconsin Public Radio*