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YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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MISO

MISO Board Orders More Detail into Monitor's 2026 Budget

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MISO held its quarterly Board Week in Detroit last week.

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FERC/FEDERAL

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SPP

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In this week's issue

Extreme Heat is Set to Test Grid Reliability, Human Resiliency

By Dej Knuckey


Dej Knuckey

Summer's officially over, white shoes have been relegated to the back of the closet, and pumpkin spice everything is back. Now that the worst of the hot weather is most likely behind us for the year, it's a good time to reflect on the pressure that extreme heat puts on the electric system.

Extreme weather has earned its way onto the short list of life's certainties. Whether it's heat waves, excessive precipitation, storms or freezes, there's a higher chance than ever that where you live or where your company does business will be affected by extreme weather in ways that are as varied as the biblical plagues.

Heat affects the full length of the electric supply chain, from generation, through the grid, to utilities' customers. In the first of a series on the impacts of climate extremes, this column will dig into the many ways hotter weather challenges the electric system.

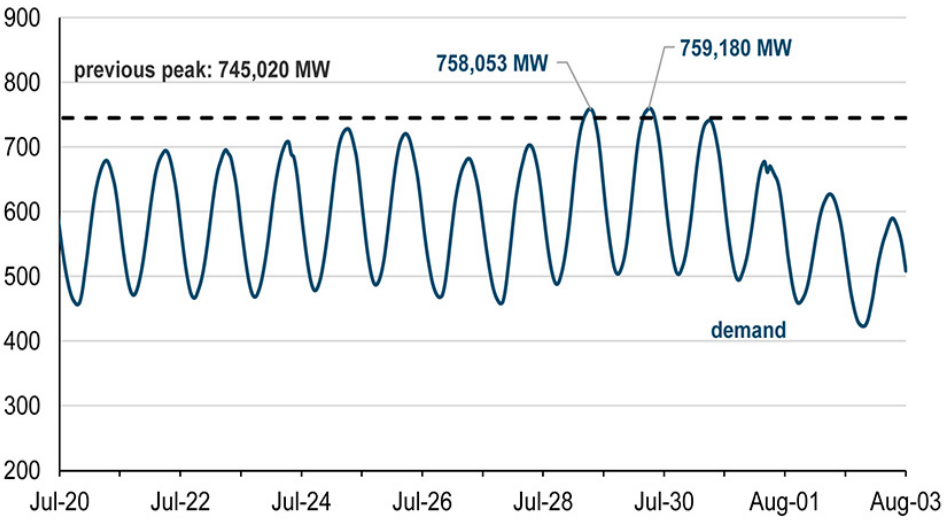
Hot Town, Summer in the City

Extreme heat drives demand spikes. On July 28, 2025, *peak demand in the lower 48 states broke the record* set in July 2024, only to surpass it the next day. The peak demand of 759,180 MW between 6 and 7 p.m. July 29, adjusted for time zones, was nearly 2% higher than the July 2024 record.

The demand is driven largely by an increase in the cooling load, though there probably were some AI servers churning out answers to heat-related questions: How can I cool my home? Will a blended margarita cool me down more than one on the rocks?

It's not a surprise that demand spikes with heat: Who doesn't want to walk into a cool home at the end of a hot commute? But heat waves are changing what these demand spikes look like. It's not just that it takes more energy to cool a home when outdoor temperatures are higher than usual, but also that those with air conditioning are using it longer.

Hourly electricity demand for the Lower 48 states from July 20 to August 3, 2025
thousand megawatts (MW)



EIA

Heat waves can show no mercy at night. Earlier in 2025, some areas in the Southwest saw *overnight lows as high as 95°F*. This means household cooling loads extended well beyond the typical peak hours from 4 p.m. to 8 or 9 p.m.

Cooling a home becomes more challenging as the heat wave lingers. *A home's thermal mass*—dense building materials such as brick, concrete or stone — absorbs heat and radiates it out during cooler periods. Usually, the thermal mass protects a home from heat (that's why it's cool inside a building with thick stone walls), but exposure to multiple days of extreme temperatures can slow down how a home cools at night and result in heat continuing to radiate after the heat wave ends.

Growing home sizes and increasing adoption of home cooling systems also increase demand. The results can be a capacity deficiency as demand spikes in areas not known for extreme heat, such as the spike *ISO-NE dealt with in June.*

The biggest change is happening in what the Building America program calls the marine climate region, which extends from the San Francisco Bay Area along the coast all the way to Canada. After record-breaking *heat waves in the Pacific Northwest* — in June 2021, Portland hit a record 116°F while Seattle hit 108°F, and then in late August 2025, *Portland* again recorded temperatures over 100°F — *installing air conditioning* in new homes is becoming common.

The bottom line: The grid will need to plan for ever-higher and longer demand spikes if it wants to maintain reliability.

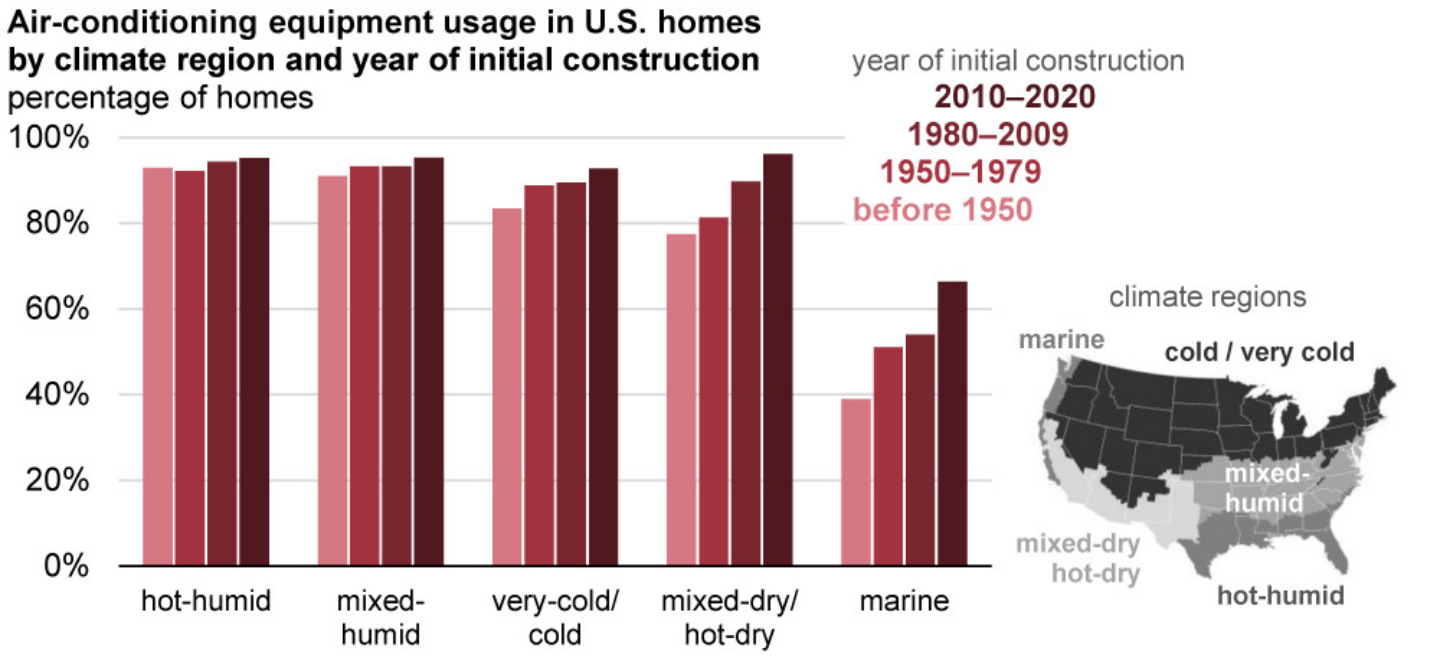
Heat Strains Supply on Many Fronts

If the only challenge were meeting those demand spikes, the electric system probably would be in good shape. But generation and the grid itself are less efficient during extreme heat, sometimes dramatically so.

The first challenge comes from hot air being less dense: Combined cycle and gas combustion plants are less efficient when the air mixed with the gas to combust in the turbines is less dense.

Efficiency losses vary based on technology, but almost all are affected by heat, according to the *Union of Concerned Scientists*: "Many types of power plants become less efficient at higher temperatures. A gas turbine rated at 60° F might be able to generate only 85% of that capacity when ambient temperatures reach 100° F, for example."

Similarly, power plants that use dry cool-



EIA

ing, which works like a giant car radiator, have difficulty when the air needed for cooling already is heated.

The bigger challenge comes from hot water: All generation plants that involve combustion require cooling, regardless of whether they burn fossil fuels or split atoms. Most use water for cooling, which means drawing from seas and the like. If that water is hotter than usual before the cooling process, it will be less efficient at cooling, and there usually are limits on discharging hot water.

For example, *nuclear reactors in Switzerland and France were throttled* after heat waves warmed the water coming in so much that it couldn't effectively cool the plants and environmental restrictions prevented them from discharging hot water into already overly warm rivers.

While most of these losses can be anticipated, extreme heat can cause extreme outcomes.

Attack of the Overheated Jellyfish

Not once, but twice this summer, the European grid had to cope with unplanned supply shocks because of [checks notes] jellyfish…?

It's a story that sounds straight out of the eco-thriller "*The Swarm*": The warming planet leads to a hotter English Channel, causing jellyfish to thrive, resulting in a *"massive and unpredictable" horde of them* in a French nuclear plant's seawater cooling system. It happened in August, and closed four of six reactors, cutting output by 3.6 GW. Less than a month later, and only 165 miles up the road, another jellyfish swarm led to the *shutdown of one reactor and the throttling of another*, taking 2.4 GW offline.

While jellyfish swarms may be unpredictable, what we can predict is that heat waves will have widespread and varied consequences.

Renewables also are Challenged by Heat

Certain types of *heat can make wind farms less efficient* too. Heat lowers air density, and wind turbines produce less power when the air's easier for the blades to pass through, so any hot day will cut production. However, when a stagnant high-pressure weather pattern settles in and creates a heat dome, the problems multiply: Low winds and less variation in wind speeds at different heights from the ground both cut output. A research paper in Europe found the impact varies by location, but one heat wave *cut wind power output by more than 30%*.

Hydroelectric output's not immune either. Early heat waves in 2023 melted snowpack in the Pacific Northwest, leaving less water flow for the summer. Overall, the May heat wave *decreased output 23%* in Washington state across the 2022/23 water year. (Like the school year, the water year is not aligned with the calendar: It starts on Oct. 1.) Of course, heat often is associated with drought, which also limits hydroelectric output.

What about solar? More sun is good, right? Not if it comes with heat. There's a reason Chile's Atacama Desert is a prime location for utility-scale solar: It's cool and sunny. Electronics are more efficient as temperatures drop, and every degree of extra heat lowers the output of a solar module.

Solar module datasheets include a measure called Pmax: the peak power the module can produce at standard operating conditions of 25°C (77°F). Right after that number, there's always a temperature coefficient: the percentage drop in efficiency for every degree Celsius above 25°C.

While newer solar modules are less temperature sensitive, most still lose around 0.35 to 0.40% efficiency for each degree. This means that back in *May, when Texas hit an early heat wave*, exceeding 100°F (38C) in Austin — more than 7°C above the average high of 87°F (30.5°C) — the solar farms were delivering at least 2.6% less peak power than they would have on a normal summer day.

That sounds like a small amount of loss, but it was significant, as ERCOT recorded peak usage of over 78 GW, setting a

record in May and again *pushing the grid to its limits in July*. And who wants their utility asking them to limit the use of air conditioning when the nights get down only to the 80s?

Even the Grid Wilts in the Heat

Like all of us, the grid is saggy and inefficient during heat waves. The power lines not only stretch, but also are less efficient conductors as the heat vibrates the conductive material and slows the flow of electrons. So, line losses, which typically consume *5% of electricity across the grid*, increase during heat waves, meaning more generation is required to deliver the same amount of electricity where it's needed.

PNNL researchers have discovered that *adding graphene to copper conductors* reduces heat-related disruptions. However, with *5.5 million of miles of transmission and distribution lines* already deployed, it's unlikely that efficiency will improve anytime soon.

Labor Sizzles as Temperatures Soar

As heat waves get longer and hotter, generation asset construction and grid upgrades and maintenance also are at risk. Heat accounts for *about $100 billion in lost productivity* nationally, and any industry where labor works outside is affected.

Some states are instituting worker protections that require breaks, shade and other cooling for outdoor workers (as someone who's at high risk of heat stroke, I have to give a shout-out to Heat Relief Depot's *phase-changing vests*). Some of those regulations have followed *heat-related deaths*. Other states, such as Florida, are doing the opposite: *banning worker protections*. But with or without protection, it's reasonable to assume outdoor worker productivity will decline during excessive heat.

Upstream is not Immune

While we've looked from generation to end user, extreme heat has effects all the way upstream in the fossil industry.

In the ultimate irony, melting permafrost puts pipeline foundations at risk of sinking and causing a *rupture in the pipeline*. It's a problem in Alaska and other arctic regions, and often is managed using passive thermosyphons (think of vertical radiators around pilings). However, hotter ambient air renders them less effective, and refreezing the permafrost under pipeline footings may require running *fossil fuel-powered chillers*.

A Hot Take on the Markets

The industry already knows how to manage hot weather. However, to think of extreme heat events as just extra hot weather is a mistake. Excessive and persistent heat, with little nighttime relief, creates challenges that are more diverse and harder to model. So, how should the electricity markets plan for extreme heat?

First, it means that the RTOs are on the right path as they aim to *raise installed reserve margins* and encourage demand response programs. And utilities should incentivize anything that can temper those peaks, from distributed energy storage to more efficient cooling technologies, such as rebates for mini-splits.

Second, as extreme heat events become more common, the industry needs to plan for them in a nuanced way. It's critical to understand the wide and varied impact on generation assets. Gas and nuclear? Keep an eye on how they keep cool. Wind? Beware of the heat domes. And given that solar's decline in efficiency in extreme heat events is easy to calculate (and has zero jellyfish-related risk), it may be time for RTOs to reconsider how they think of solar's reliability. It's not just about generation assets: The industry's ultimate asset is its people, so thinking about worker safety also is critical.

Finally, extreme heat risk reinforces the need to diversify generation and consider where energy storage assets can best act as a shock absorber for the grid. They are, of course, useful sited next to intermittent generation assets, but there's a strong argument to think of all generation assets as intermittent when extreme heat events are concerned. ■

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

Livewire: Renewables Ready to Out-innovate, Outlast Trump

By K Kaufmann


K Kaufmann

The U.S. clean energy industry is so over tax credits.

The passage of the Republicans' *One Big Beautiful Bill Act* — extending President Trump's 2017 tax cuts and decimating former President Biden's 2022 renewable energy tax credits — was a shock to the system and already is slowing the growth of solar and wind in the United States.

But slowing down was not at all on the minds of the 37,000 industry professionals — and 1,325 exhibitors — who descended on Las Vegas Sept. 8-11 for RE+, the largest renewable energy trade show in the country.

What I heard, at more than one session over the four-day conference, was that if the industry had to lose the federal incentives, it could not have happened at a better time. Trump's scorched-earth war on renewables may be a political reality, but the exploding growth in electricity demand from data centers, manufacturing and electrification is driving economic and technological change at a scale and speed well beyond the president's control.

New figures from industry analyst Wood Mackenzie show that U.S. utilities currently have 17 GW of new electricity projects under construction specifically for large loads like data centers. An additional 99 GW of large-load projects are "committed," meaning they have interconnection agreements, contracts or other solid financial arrangements.

Solar and storage made up 82% of new generation coming online in the first half of 2025.

"So, we're in this state where there's sort of two truths, two experiences, two realities," said Abigail Ross Hopper, president and CEO of the Solar Energy Industries Association, which sponsors RE+ with the Smart Electric Power Alliance.

While the politics may remain "intensely chaotic and intensely unpredictable, there's opportunity for entrepreneurship; there's opportunity for innovation; there's opportunity for success," Hopper said during an industry update Sept. 10. "The market will take over politics, and we will ultimately win."

Bifurcated Realities

I experienced a similar sense of bifurcated realities at RE+ as I attended panels and workshops and cruised the trade show floor.

Politics remains the industry's Achilles' heel. Leaders have yet to let go of their quixotic belief that at some point, they will be able to break through the ideological noise in Washington, D.C., with facts, figures and common sense.

A panel on how to frame clean energy policies for conservatives basically replayed many of the talking points I have been hearing at energy conferences for the past year or more, even before Trump was elected for a second term.

Eric Goodwin, vice president of business development at OMCO Solar, a steel company that manufactures solar tracking systems, talked about keeping a focus on jobs and drawing Trump's attention through targeted use of social media.

Heather Reams, president and CEO of Citizens for Responsible Energy Solutions, a right-leaning clean energy advocacy group, argued that, the OBBBA notwithstanding, the industry must continue to engage with congressional Republicans. Like Hopper, Reams called for a shift in priorities, from tax credits to innovation.


The Trade Show floor at the RE+ conference in Las Vegas Sept. 8-11, 2025. | © RTO Insider

Why This Matters

Under Trump's drive to stand up new fossil-fueled and nuclear generation is the assumption that the need for new power can be met only with traditional, 24/7 dispatchable forms of generation. But radical and rapid growth in electricity demand presents complex challenges that call for new and complex solutions.

Tom Starrs, vice president of regulatory affairs at EDP Renewables, and Isaiah Menning, external affairs director of the American Conservation Coalition, both stressed the importance of building local support in rural areas where solar and wind projects often face opposition.

As always, the views and voices expressed here were authoritative, thoughtful and pragmatic, and unlikely to have any major impact. The problem is we have a president and administration that have little to no interest in facts that in any way counter their own skewed, fossil-fueled vision of what American energy policy might look like.

They are equally uninterested in any kind of constructive dialogue with the renewable energy industry, as witnessed by the almost complete absence of representatives from the Department of Energy at RE+, from Energy Secretary Chris Wright on down.

PERC vs. TOPCon

Had Wright been there, he would have seen an industry that is vital, optimistic and determined to out-innovate, out-AI and outlast Trump and his backward-looking energy policies.

Artificial intelligence was everywhere, with a small army of startups rolling out new products that can cut times and cost to design virtual power plants and microgrids, review contracts or local

ordinances, promote home electrification and send robots to inspect solar panels out in the middle of nowhere.

Solar and storage companies from China and India also were highly visible on the trade show floor, many of them figuring out how to work around Trump's tariffs and comply with OBBBA's stricter domestic content requirements.

SolarSpace, a top Chinese manufacturer of solar cells and panels, is partnering with several American investors to build a solar manufacturing plant, according to John Van, a sales manager. While he was reluctant to provide details or name names, he said the new plant is scheduled to go online by the end of the year, and half of its initial 2 GW of panel capacity already is sold.

What's significant here is that SolarSpace and other Chinese and Indian companies are producing solar cells and panels that are more efficient and durable than cells and panels currently being manufactured in the U.S. The American industry still is using *PERC* (passivated emitter and rear cell) technology, while the rest of the world has moved on to *TOPCon* (tunnel oxide passivated contact) and *HJT* (heterojunction with intrinsic thin layer) technologies. (The links connect to fairly wonky descriptions of the technologies.)

TOPCon and HJT panels are more expensive, but more efficient, which means projects using these technologies may not need as much land — a core issue for solar projects in rural areas. But rolling out these advanced technologies in the U.S. has stalled, in part due to *legal disputes* over intellectual property and patent ownership.

U.S. producers also have stuck with PERC because they can manufacture more panels at lower prices, despite their lower efficiency and durability.

In other words, Trump's tariffs and domestic content requirements are not advancing the onshoring of solar manufacturing or fostering U.S. competitiveness, while Chinese and Indian firms are figuring out the business models that will enable them to enter the U.S. market and potentially offer better products.

The Interoperability Challenge

What one could see and hear at RE+ — at least what I've written about so far — is the tip of the proverbial iceberg, what's visible above the water line. The changes needed to respond to current system challenges — political, economic and technological — can happen only when you drill down to explore the patterns, trends, behaviors and attitudes that lie below, according to Matt McDonnell, managing partner of the Current Energy Group, a policy and analysis outfit.

McDonnell was one of the speakers at a half-day workshop Sept. 8, laying out a holistic, "systems thinking" approach to grid planning and design, sponsored by the GridWise Architecture Council, commonly called GWAC.

"What are the assumptions and beliefs that people hold about the system? How do we really, really challenge some of these things that we take for granted … conventional wisdom, the way things have always been done?" he said.

Part of working toward such fundamental changes in the electric power system means nudging regulators and other industry stakeholders "down this iceberg model stack to really be challenging some of these underlying features that are below the surface often in proceedings."

Taking the example of grid resilience following extreme weather events, traditional patterns and thinking might focus on grid upgrades or "hardening" that "drives up costs while often offering suboptimal performance," McDonnell said. "Poles keep getting rebuilt and ice storms come through and keep knocking them down."

Should the focus be on grid reliability or "energy service reliability?" he said. "Is what we really care about the poles and wires staying up all the time, or do we care about customers having access to energy even during extreme weather events?"

GWAC sees this kind of systems approach as integral to developing flexible and interoperable energy services that will allow individual buildings or groups of buildings — like data centers — to interact with the grid, from distribution up to transmission, to improve reliability and cut costs for consumers.

The proliferation of grid-edge technologies has created an "interoperability challenge," said Shawn Chandler, a director at consulting firm Guidehouse. Distributed generation and computing power can be combined "to get all that sensing and all that information into a hybrid, decentralized system that brings together … system distribution operations, customer service, market operations and regulators."

"If you can do that, then all your information flows are leading to the same outcome, which is [that] we want the most optimization, and most importantly, we avoid what I would call unintended consequences," he said.

Ultimate Inertia

The language may be a bit abstract and jargony, but the connections to the industry's current debates on how to meet demand growth are immediate and clear.

Under Trump's drive to stand up new fossil-fueled and nuclear generation — at the tip of the iceberg — is the basic assumption that the need for new power can be met only with traditional, 24/7 dispatchable forms of generation.

What drives such assumptions is the deeply engrained industry desire for quick and simple solutions that require little change in business or regulatory models, an approach that increasingly is untenable.

Radical and rapid growth in electricity demand presents complex challenges that call for new and complex solutions.

The factors under the waterline here include backed-up supply chains for natural gas turbines, with delivery times of three to five years or more. Building out new plants, natural gas pipelines and transmission lines could mean ongoing utility bill increases for consumers, an unintended consequence and political minefield for any candidate for public office. New approaches to affordability will be critical.

Technology may move faster than policy or regulation, but the ultimate inertia in the system is rooted in human attitudes and behavior. What I saw at RE+ is that clean energy is moving fast and more than ready to embrace the complex challenges ahead. Trump or anyone else holding on to simple, outdated solutions will be left in the dust. ■

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

Will the Supreme Court End FERC's Independence?

What Will Happen at FERC if Humphrey's Executor is Overturned

By James Downing

President Donald Trump is poised to have more than one of his own nominees on FERC for the first time in his second term, and, coupled with ongoing cases working their way through the courts, that has raised questions about the future of its independence.

When asked about FERC's independence during their confirmation hearing in early September, both Laura Swett and David LaCerte gave the standard answer of following the law and FERC's internal rules and regulations. But depending on the results of several cases, the laws governing the commission and other federal agencies could go through some major, radical changes. (See *Senators Focus on FERC's Independence at Swett, LaCerte Confirmation Hearing*.)

The argument against independent agencies comes from subscribers of the "unitary executive theory" which, as Project 2025 said, finds them "constitutionally problematic" because in their view, the opening line of Article II of the Constitution vests executive power solely in the president.

While they exercise executive authority, independent agencies are largely free from White House influence, in part because of laws limiting the president's ability to fire their members to certain circumstances. These laws were deemed constitutional in 1935 in *Humphrey's Executor v. United States*, a case that proponents of the unitary executive have made a target for the Supreme Court revisiting. The precedent is being tested by Trump firing members of several independent agencies and the resulting wrongful termination lawsuits, and many observers see *Humphrey's Executor* on the chopping block before the current justices.

"What [*Humphrey's Executor*] says is that Congress, when enacting statutes, creating or regulating agencies, can condition or limit the president's ability to fire certain officials for things like misuse of office," Yale Law School associate professor Joshua Macey said in an interview. "It's called 'for cause removal.' And, so, the sort of recent trend by the Supreme Court is towards the unitary executive thesis, which says that the president can fire any agency official for any reason whatsoever."

Why This Matters

FERC has long been insulated from the winds of political change, but a key legal precedent underpinning that independence being under threat has the industry wondering what that could mean for how it is regulated by the agency.

Beyond the legal issues are "norms-based arguments" about whether a president should be able to control everything an agency does. "The president has shown that he's willing to basically use all the tools at his disposal to control agencies," Macey said. "With FERC, he's been a little bit more reluctant."

But the Department of Energy's use of Section 202(c) of the Federal Power Act to keep two old fossil-fired power plants running this summer (and extending both orders this fall) was unprecedented. Macey also cited recent efforts to unseat Federal Reserve Governor Lisa Cook over allegations of mortgage fraud as another example of the White House trying to effectuate the unitary executive theory.

And while naming Democratic FERC Commissioner David Rosner as chair appeared bipartisan on its face, sources told *RTO Insider* they saw it as Trump exerting control over the agency. Under the precedent of the chair being of the same party as the president, Commissioner Lindsay See, the lone Republican on FERC, would be expected to be chair. (See *FERC Independence Likely Coming to an End with Christie's Exit*.)

Ari Peskoe, director of Harvard Law School's Electricity Law Initiative, pointed to the department's Notice of Proposed Rulemaking during Trump's first term as the kind of policy that the administration might try to impose if the unitary executive theory prevails at the Supreme Court. The proposed rule, rejected unanimously by a FERC comprising a majority of Trump's nominees, would have paid power plants with on-site fuel their full operating costs.

"Congress designed agencies like FERC to operate somewhat independently from the White House," Peskoe said. "I think part of the reason for that is for the stability of these industries. And particularly for energy industries regulated by FERC, that are making such large investments … unstable policies like we've seen at some politically controlled agencies would I think be disastrous for the development of energy infrastructure."

So far, the Supreme Court has only dealt with the issue by overruling injunctions against firings from lower courts, Peskoe said. In one such *decision* in May, in a case involving the National Labor Relations Board and the Merit Systems Protection Board, Chief Justice John Roberts wrote that the government was likely to show both agencies "exercise considerable executive power."

The court said it would benefit from full briefing and argument on the case, which is currently awaiting a final decision from the D.C. Circuit Court of Appeals.

"I've been reloading the D.C. Circuit opinion page every day to see whether it will rule on the merits, and that's the case that I think would be the vehicle for getting this issue on the merits to the Supreme Court," Peskoe said.

'Distinct Historical Tradition'

The only case that has brought the *Humphrey's Executor* issue as applied to FERC directly before the Supreme Court is an appeal of an enforcement action the agency issued against energy efficiency provider American Efficient, which has challenged the legality of the commission itself. (See *FERC Seeks Nearly $1 Billion in Penalties from EE Provider in MISO, PJM*.)

"We'll see what the Supreme Court ultimately says," Peskoe said. "There's a lot of ways this could go that maybe would not impact FERC directly. What the Supreme

Court has suggested is that somehow the Federal Reserve may be different than other agencies. Maybe there's a way that FERC could also be different from other agencies."

In that May decision, Roberts wrote that the Federal Reserve "follows in the distinct historical tradition of the First and Second Banks of the United States."

Peskoe argued that FERC has its own "distinct historical tradition" in the form of ratemaking commissions, most notably the Interstate Commerce Commission (ICC), a federal railroad regulatory agency created in 1887 that had the same "for cause" removal conditions for commissioners.

"Congress' goal there was to create deliberative bodies — not political bodies — that were going to handle the sensitive issue of regulating the railroads and setting their rates in terms of service," he added. "That's a ratemaking model that persisted as Congress regulated numerous industries under basically the same law over the next 50 or so years, and many of those issues don't really exist anymore. But FERC is kind of the descendant of the ICC, and when the courts look at these separation-of-powers issues, that history may very well be relevant."

Ratemaking is a legislative function, not an executive function, and that could help to distinguish FERC, assuming underlying legal precedents change, Peskoe said.

"Congress and state legislatures were completely incapable of doing this, and there were two basic reasons for this," Macey said. "The first was rate cases. The question of 'Can Congress review investment and then approve rates that will be passed on to captive ratepayers?' is an enormously complex and time-consuming endeavor, and no Congress or state legislature had any interest in doing it.

"The second thing is, there's a time lag. You need to consistently review these things. It's not really possible to say we're going to come in once a year, once every two years, and regulate. You need to look at investments in a dynamic fashion over time. That requires expertise, but it also requires a built-out staff whose full-time job is to do this."

The Federal Reserve is likely to get an exemption from the end of *Humphrey's Executor*, Macey said, but it is much less likely that FERC would get one. That leaves two questions, he said: whether there is any value to FERC independence, and whether adjudicatory agencies are exempt.

"FERC does a lot of adjudication," Macey said. "Utilities file tariffs with FERC, and FERC either approves or rejects those tariffs; that looks less like rulemaking than like adjudication. And typically, we think adjudicator judges need to have some amount of independence because of due process reasons. We have to decide adjudication on the law, not based on political considerations."

The Supreme Court has not touched that issue, but it will be forced to once the "for cause" protections are removed from FERC and other adjudicatory agencies, Macey said.

Ex Parte Communications

FERC's *ex parte* rules already distinguish between its adjudicatory function and its rulemaking function: Commissioners cannot discuss pending rates, but commission chairs have often discussed rulemakings with the White House in past administrations.

Whether the Trump administration would want to intervene in adjudications before the agency in an open question, but the anti-wind policies at other agencies show that the White House cares about certain electricity issues more than others.

"My own view is that probably the primary justification for agency independence is that some matters involve significant expertise, and there is a real benefit to having to not completely immunizing them from political trends but at least limiting the kind of whipsaw reaction that comes in with a policy change every four years," Macey said.

Presidents will always influence FERC policy, Macey noted, even if that remains solely through the power to nominate commissioners and appoint the chair. While drastic actions like freezing permits for clean energy resources might seem like they favor an administration's interest, they lead to unintended consequences, he said.

"I think they are pretty bad for capital markets and investment because investors like stability much more than they like a policy that slightly favors their own interests," Macey said.

The U.S. Supreme Court | *Shutterstock*

FERC would have to change its *ex parte* rules, or at least how they are interpreted, to start talking about ratemaking cases with the White House, Paul Wight, a partner at DLA Piper and a former FERC staffer, said in an interview.

"There's a couple of positions where there could be changes in the way it's currently interpreted," Wight said. "One position could be it's not obvious that White House communications with FERC would always be prohibited by these *ex parte* rules. That's a legal question."

FERC *ex parte* regulations are arguably stronger than what the law requires, he added. But allowing for White House communications "would be a big change."

"If they wanted to change the regulations, they would have to go through a process, and there would have to be comments from parties on whether or not this is a good policy to allow more direct communication," Wight said.

The industry wants transparency around the commission's regulations and, with its need to manage long-term, major investments, it also values certainty.

"You want to know what the process is and [whether] it's fair," Wight said. "There's a lot of strong policy points to be made, [but] if you went to a less independent commission with more direct White House control, it would definitely be a change in the industry. It would be something that folks would have to adapt to. And, you know, I could see pros and cons, perhaps.

"We haven't lived in that regime, but I think the history of FERC independence [has] been a hallmark of FERC, and I think it served the industry very well." ■

FERC Focusing on Large Loads, Clearing the Decks Under Rosner

By James Downing

FERC held its monthly open meeting Sept. 18 amid something of an interregnum period as it awaits two nominees to fill empty seats, with Chair David Rosner saying one of his goals during his tenure is to clear out old proceedings.

"We've been focused on methodically clearing out longstanding proceedings that, in some cases, have been pending before the commission for years," Rosner said. "Several of these are on the agenda today."

One such longstanding item FERC recently terminated was a Notice of Inquiry that Chair Kevin McIntyre launched in 2018 looking into how the commission could update how it approves natural gas infrastructure, Commissioner Lindsay See noted during the open meeting (*PL18-1*). McIntyre died in office before the proceeding wrapped up, but it was picked up by Chair Richard Glick, who wanted FERC to address greenhouse emissions from gas infrastructure, a policy that sunk his renomination. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

"The draft statement was getting in the way of this goal of regulatory certainty by introducing potential confusion and giving avenues for legal vulnerability," See said.

FERC issued an order terminating the proceeding on *Sept. 12*, two weeks after Energy Secretary Chris Wright *wrote* to the commission asking it to axe the fallow docket.

FERC Chair David Rosner | *FERC*

The commission also moved on more current issues, with Rosner releasing a *letter* he sent to all six jurisdictional ISOs and RTOs asking them for information on best practices around load forecasting in light of growing demand driven by data centers and other sources.

"At a time when utilities forecast hundreds or thousands of megawatts of growth, improving forecasts by even a few percentage points in the right direction — up or down — can impact billions of dollars in investments and customer bills," Rosner said in the letter. "Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible."

Rosner posed several questions in the letter, including asking grid operators how they, regional utilities and state regulators in their territories obtain information that verifies when and whether prospective large loads will reach commercial operations. He also asked how consistently large loads are screened before being included in forecasts.

Another question is how grid operators forecast the actual consumption of large loads compared to their requested level of interconnection service. FERC also asked how the RTOs coordinate with each other and utilities at the regional or interregional levels to share best practices on large load forecasting and ensure requests are not double counted.

Ultimately, the customers that are creating the load growth are at the retail level, which means they are regulated by states who play key roles in feeding information up to the ISO/RTO forecasts. Rosner said he was only interested in what the organized markets under FERC's jurisdiction can do.

"I'm very interested in doing things that are purely within their ability to control," Rosner said. "We're not asking any state to do anything different. We're asking the RTOs to say, 'Hey, what are your best practices,' just to make sure we're accurate, because being either high or low means that we're not planning for an efficient set of infrastructure to meet the challenge."

Why This Matters

The meeting gave Chair David Rosner (D) a chance to lay out his priorities at the helm of FERC, though the length of his tenure is unknown as two of President Trump's nominees, both Republicans, await confirmation by the full Senate.

While Rosner said he views reliability as FERC's most important job, he is also focused on enabling economic growth by ensuring abundant supplies of energy.

"I'm really excited about infrastructure," Rosner said. "I think we need to build, build, build. America needs every electron on every molecule of every type we can get, and we need more infrastructure to move it."

Reliable and affordable energy is not just a prerequisite for residents and businesses; it is vital to winning the race for artificial intelligence, he said.

When it comes to AI and the related growth in demand from data centers, FERC has had a pending case on issues around co-locating loads at existing power plants since November 2024, when See and former Commissioner (and later Chair) Mark Christie voted against allowing Amazon Web Services to use more of a Talen Energy nuclear plant's capacity in such a deal. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

"We also have our open matter when it comes to co-located load," See said. "I just want to highlight that FERC is not the only player when it comes to the many questions in these areas."

See said she is excited to see what policies around large loads come out of states and the grid operators but that it is important that FERC deal with those issues before it, and the co-location proceeding can be brought to a close soon.

"This is a top priority," Rosner said. "It's also a very complicated topic. My colleagues and I have been working hard on this. I'm really excited about co-location and everything in between, and getting the rules of the road in place so that we can unlock all these new technologies, get them on the grid and get data centers built."

FERC Commissioner Lindsay See | © RTO Insider

The co-location proceeding is pending and contested, meaning commissioners are limited in what they can say publicly under *ex parte* rules, but Rosner said that FERC was working to adjudicate the record and move something forward.

Load growth is very much top of mind for the industry, and Commissioner Judy Chang noted that the new proposals to help manage it are going to be filed with FERC in the near future.

"I anticipate we will receive more filings in these coming months from utilities and RTOs proposing reforms or changes in how they integrate new resources, integrate those resources with load, or how they integrate those resources with their existing or new transmission planning processes, and really how to handle these large loads on the system," Chang said. "I'm committed to learning more about these large loads so that I can do my job effectively." ■

Judge Lifts BOEM's Stop-work Order on Revolution Wind

OSW Project is 80% Complete, Racking up Losses amid Delay

By John Cropley

A federal judge has lifted a stop-work order on Revolution Wind, handing a rare victory to the U.S. offshore wind industry amid the Trump administration's relentless effort to torpedo it.

Judge Royce Lamberth issued the directive Sept. 22 in response to Revolution Wind LLC's Sept. 4 complaint in U.S. District Court for D.C. (1:25-cv-02999).

The U.S. Bureau of Ocean Energy Management slapped the stop-work order on Revolution Wind on Aug. 22, offering vague references to threats to national security and potential interference with reasonable uses of territorial waters.

Revolution in its counterclaim said the order was arbitrary and capricious, violated the due process clause of the Fifth Amendment and is beyond statutory authority.

On Sept. 22, Lamberth granted Revolution's request for a stay and injunction, writing: "Revolution Wind has demonstrated likelihood of success on the merits of its underlying claims, it is likely to suffer irreparable harm in the absence of an injunction, the balance of the equities is in its favor, and maintaining the status quo by granting the injunction is in the public interest."

Offshore wind construction is extremely expensive. The idle month likely has cost Revolution tens of millions of dollars and potentially set up a series of future costs, such as extended vessel charters due to the delay.

Later Sept. 22, Revolution Wind said it would resume construction work as soon as possible. It said its lawsuit challenging the stop-work order will progress, but also said it would continue to seek collaboration with the Trump administration and other stakeholders to find a resolution.

Revolution Wind is a 50-50 joint venture of Ørsted and Skyborn Renewables through their subsidiary, Revolution Wind LLC.

The project has its roots in a September 2013 federal auction of a seabed lease south of Rhode Island and Massachusetts. After years of planning and review, BOEM issued a record of decision in favor of Revolution in August 2023 and approved its construction and operations plan in November 2023. Construction was approximately 80% complete when halted, and commercial operation had been targeted for 2026.

The project is designed to produce a maximum of 704 MW of electricity; Rhode Island and Connecticut have agreed to take 400 MW and 304 MW, respectively.

A foundation for the Revolution Wind project is placed off the New England Coast in 2024. | *Revolution Wind*

Why This Matters

The injunction is a rare victory after a long series of setbacks for the U.S. offshore wind sector at the hands of the Trump administration.

Trump launched his attack on offshore wind power hours after his second inauguration, and his administration soon commenced a thorough and effective effort to block development. However, most of the measures have been directed at early-stage projects, or later-stage projects that have received BOEM approvals but have not yet begun construction.

The five projects now under construction have not been targeted as clearly. An April stop-work order against Empire Wind was widely seen as an attempt to muscle through two natural gas pipeline proposals, and BOEM allowed work to resume in May after New York agreed to consider the pipeline plans.

If the Trump administration has an ulterior motive for stopping work on Revolution Wind, it has not surfaced.

BOEM did not immediately respond to the Sept. 22 injunction or indicate what its next move would be.

But however fleeting the court victory may turn out to be, it drew cheers from national trade group Oceantic Network:

"Today's decision allowing work to resume on Revolution Wind is welcome news for the hundreds of skilled workers who can now return to their jobs while the legal process continues. Revolution Wind is critical to securing New England's electric grid, lowering energy costs for businesses and families, strengthening the local supply chain, and achieving energy independence. This Made in America energy project is putting Americans to work building reliable, affordable power to communities across New England that desperately need it." ■

House Members Release Bipartisan Permitting Legislation Framework

By James Downing

The Problem Solvers Caucus, a bipartisan group of House members, has released a *framework* for energy infrastructure permitting legislation as momentum for a bill grows in Congress.

The caucus' Permitting, Energy and Environment Working Group, led by Reps. Scott Peters (D-Calif.) and Gabe Evans (R-Colo.) and co-chairs Reps. Brian Fitzpatrick (R-Pa.) and Tom Suozzi (D-N.Y.), developed the framework over the past few months by working with energy producers, industry experts, members of relevant congressional committees and other stakeholders.

"America faces a choice between cheap, abundant energy from all-of-the-above sources or higher energy prices, falling behind China and an increased risk of blackouts," Peters said in a statement. "It's obvious where we need to go. To get there, we know we need to update our environmental laws to meet the challenges of today and invest in a grid for this century. This platform represents a bipartisan commitment to set aside ideology and solve this problem for the American people. I look forward to working with my colleagues to keep the momentum going and turn this into legislation that can pass both chambers of Congress."

The framework for permitting reform covers a range issues from efforts to streamline reviews under the National Environmental Policy Act to changing how the largely untested National Interest Electric Transmission Corridors (NIETCs) work by allowing just one line (rather than a broader region) to qualify as a corridor. The NIETCs are designated by the Department of Energy and any lines qualify for backstop siting at FERC.

Construction on the Cardinal-Hickory Creek line | *ATC and ITC Midwest*

The NIETC process would be amended to allow for simultaneous state and federal reviews (recognizing state authority), and it would require DOE to act on applications within 90 days.

The process for judicial review of DOE- and FERC-approved linear infrastructure projects would be consolidated under the exhaustion and judicial review provisions of the Federal Power Act.

The framework includes categorical exemptions for simple updates to existing linear infrastructure, especially in disaster-prone areas. The Forest Service's management and wildfire mitigation activities in utility rights-of-way should be expedited.

To help meet rising demand, the framework calls for FERC to initiate interregional planning (excluding ERCOT), with Congress providing "strong guidance on the allocation of the costs of these infrastructure projects" while excluding cost allocation to customers who receive no or trivial benefits.

On domestic supply chains, the Problem Solvers Caucus calls for DOE to "regularly assess electricity generation and transmission supply chains for security and resilience."

"Reforming our permitting system is crucial, and this framework meets the moment for much-needed change. The demand for affordable and reliable energy of all kinds becomes increasingly urgent," Evans said in a statement. "By cutting through red tape, we can meet energy demand, lower costs, strengthen national security and create high-quality jobs in America, while being responsible stewards of the environment and maintaining our position of global leadership and not cede ground to China. The urgency is real, and I am proud of this bipartisan push for change."

The caucus' permitting reform framework was welcomed by Grid Action Executive Director Christina Hayes, who said it shows Democrats and Republicans can come together to find solutions that strengthen the grid, cut red tape and speed up the development of transmission infrastructure.

"As demand for electricity soars, driven by the rapid growth of artificial intelligence, new data centers, and the everyday needs of families and businesses, the urgency of bipartisan action has never been clearer," Hayes said. "This framework recognizes that meeting those demands means modernizing our permitting system so that transmission projects can move forward quickly, reliably and affordably." ■

Why This Matters

Congress has been trying to pass permitting legislation in recent years and it will take a bipartisan effort. This framework has been agreed upon by lawmakers from both parties.

DOE Launches Speed to Power, Eyes Multi-GW Projects

Request for Information is Latest Trump Administration Effort to Address Grid and AI Needs

By John Cropley

The U.S. Department of Energy is kicking off its Speed to Power initiative by seeking input on large-scale grid projects that would serve large-scale data centers.

The move is the latest in a series of efforts President Donald Trump initiated hours after his inauguration to boost American energy production. There has been an emphasis on boosting production and consumption of fossil fuels while hindering development of intermittent renewable energy resources, but energy infrastructure also is a priority.

DOE said Speed to Power is centered on multi-gigawatt generation, transmission and grid infrastructure projects that will enable the U.S. to accelerate artificial intelligence buildout.

"With the Speed to Power initiative, we're leveraging the expertise of the private sector to harness all forms of energy that are affordable, reliable and secure to ensure the United States is able to win the AI race," Energy Secretary Chris Wright said in a *Sept. 18 news release*.

The same day, DOE's Grid Deployment Office issued a *request for information* that would help it identify projects that enable minimum incremental load of 3 GW and support up to 20 GW of incremental load.

These can include building new interregional transmission (minimum 1,000 MVA); reconductoring existing lines (minimum 500 MVA); bringing retired thermal generation facilities back online or using their interconnection capacity for new "reliable" power generation; and constructing new generation.

DOE reminded respondents about the funding and technical assistance programs available for such projects.

Responses are due by Nov. 21.

Speed to Power is supported by a data viewer created by DOE's *National Renewable Energy Laboratory*.

The interactive map offers some of the information developers need as they conduct site assessments, including: power demand from data centers that are planned, under construction or in operation; fiber-optic cable networks; transmission lines; power plants; substations; natural gas pipelines; day and night population; NERC reserve margins; FEMA risk indexes; and railroads.

Why This Matters

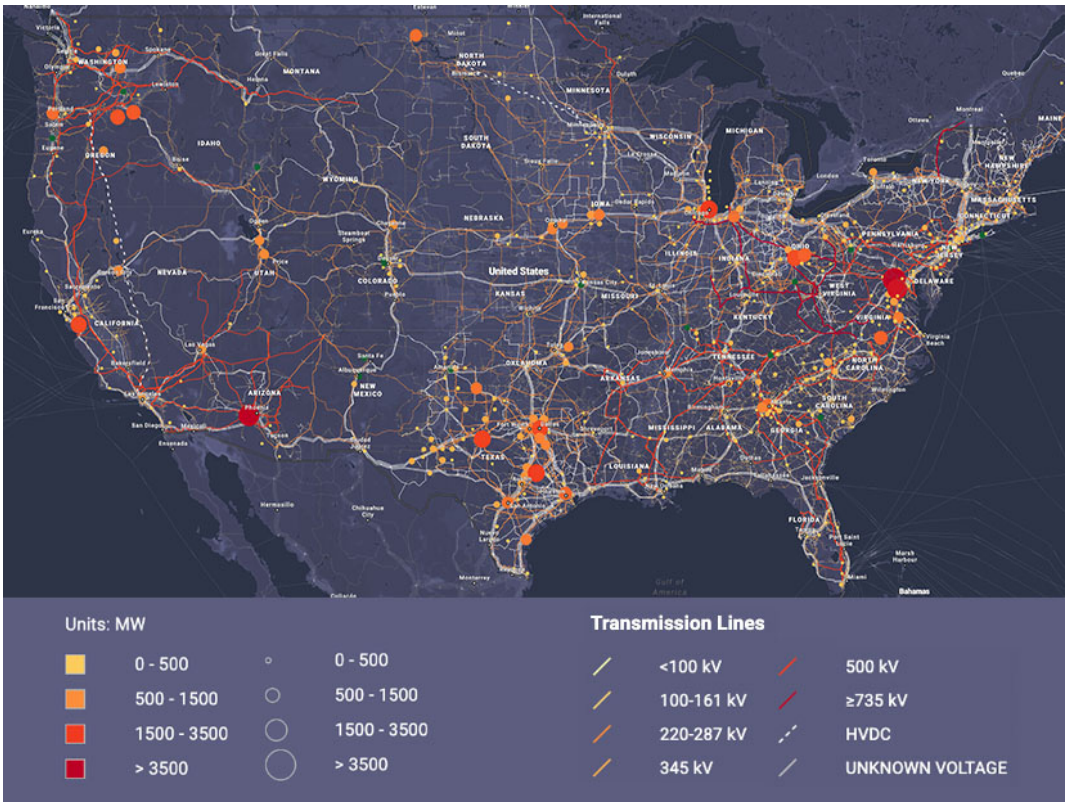
The DOE is moving to expedite large-scale generation, transmission and grid projects — in large part to meet AI data center demand.

DOE said Speed to Power evolved from Trump's Day One declaration of a *national energy emergency* and his orders "*Unleashing American Energy*" by emphasizing fossil fuels, *removing barriers* to American leadership in artificial intelligence and strengthening the *reliability and security* of the U.S. grid.

Also leading up to Speed to Power, DOE conducted and published an *evaluation of grid reliability* that concluded retirements of existing generation assets and delays in additions of new firm power will lead to a surge in power outages. (See *DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030*.)

Some expert observers faulted details and conclusions of the report, but DOE continues to cite the document as it lays out strategies. (See *Industry Experts Find Faults in DOE's Resource Adequacy Analysis*.)

DOE said its launch of Speed to Power will "ensure the United States has the power needed to win the global artificial intelligence race while continuing to meet growing demand for affordable, reliable and secure energy." ■



The National Renewable Energy Laboratory's Speed to Power Data Viewer is an interactive map showing data center power demand and various infrastructure datapoints. | *NREL*

Newsom Signs Calif. Pathways Bill into Law

Bill Part of Larger Energy Package

By Henrik Nilsson

California Gov. Gavin Newsom has signed into law the bill that will allow CAISO to transition the governance of its markets to an independent "regional organization," along with five other bills related to energy and emissions.

AB 825 implements the West-Wide Governance Pathways Initiative's "Step 2" plan to create a regional organization to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market — and authorize the ISO and California's investor-owned utilities to participate in the RO. (See *Pathways Bill Passes Calif. Legislature in Lopsided Votes*.)

Speaking during a Sept. 19 signing ceremony at the California Academy of Sciences in San Francisco, Newsom said the law will generate almost $1 billion in financial benefits, expand clean energy exports and address reliability.

Referring to previous failed efforts to pass legislation to regionalize CAISO into a Western RTO, the governor said, "We've worked on that for over a decade."

"We're getting it done here today," Newsom said. "So, finding a balanced approach, setting forth strategies to achieve audacious goals that simply no other large-scale jurisdiction in the world can lay claim to, and do it in a way that reduces the burden on ratepayers and taxpayers at the same time."

Supporters of the bill were quick to thank Newsom and the California Legislature after the governor approved the measure.

"Gov. Newsom's signing of Assembly Bill 825 is a landmark achievement for the future of energy collaboration and innovation across the western United States," CAISO said in a statement. "He, along with the California Legislature and the broad coalition of supporters, have recognized the importance of making this crucial next step toward independent governance of Western electricity markets. Now that AB 825 is signed into law, the ISO will work closely with partners across California and the rest of the region to ensure a more reliable and affordable bulk electric system for the benefit of consumers throughout the West."

California Gov. Gavin Newsom speaking during the signing ceremony of AB 825 on Sept. 19. | *California Governor's Office*

Why This Matters

Newsom's signing of AB 825 marks a significant victory for longtime advocates of expanding CAISO into a regional organization.

Advanced Energy United highlighted the many stakeholders involved in drafting the legislation.

"This legislation is the culmination of nearly a decade of work to create a more flexible, reliable and affordable energy future for the West," said Leah Rubin Shen, managing director at Advanced Energy United. "AB 825 paves the way for an independently governed energy market that will deliver a more reliable grid, broader deployment of clean energy resources and more affordable energy for consumers across the region."

Speaking during the signing ceremony, Katelyn Roedner Sutter, California state director at the Environmental Defense Fund, said, "By expanding today's energy markets, we expand access to clean electricity and lay a strong foundation for the growth of clean energy and jobs."

A broad coalition was responsible for getting AB 825 passed, Sen. Josh Becker, the bill's chief sponsor, told *RTO Insider* at New York Climate Week.

Continued on page 19

New Challenges Await Pathways After Success in Calif. Legislature

AB 825 Opens Door for Unified Western Market, Staks Says

By Henrik Nilsson

With California lawmakers passing the bill designed to transition the governance of CAISO's markets to an independent "regional organization" (RO), new challenges await the West-Wide Governance Pathways Initiative as the coalition seeks to turn a once-elusive goal into reality.

In an interview with *RTO Insider*, Kathleen Staks, co-chair of the Pathways Initiative's Launch Committee and executive director of Western Freedom, discussed the future of the multistate RO that will oversee CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), the latter set to launch in 2026.

Nine state utility commissioners and energy officials launched the Pathways Initiative in a July 2023 letter outlining their desire for increased coordination and expansion of electricity markets in the West. (See *Regulators Propose New Independent Western RTO*.)

The primary obstacle to realizing that goal has been California's oversight of CAISO, which operates the markets and whose Board of Governors is appointed by the state's governor.

"Nobody wants to participate in something where one state has the ability to choose the governing body members," Staks said.

Previous legislative efforts to regionalize CAISO have failed because those asked California to completely relinquish control of CAISO's balancing authority and transmission functions, Staks explained.

Why This Matters

With the passage of AB 825, the Pathways Initiative's work is far from over, as it still has to seat a board and ensure sufficient funding for the project to succeed.

Kathleen Staks, co-chair of the West-Wide Governance Pathways Initiative's Launch Committee | *Western Energy*

Pathways took a different approach. Over the course of 18 months, Staks and her team designed the RO to only oversee CAISO's markets while preserving the ISO's role in planning California's grid.

The California legislature voted to approve the initiative's "Step 2" plan on Sept. 13, authorizing the ISO and California's investor-owned utilities to participate in the RO. (See *Pathways Bill Passes Calif. Legislature in Lopsided Votes*.)

But the work is far from over.

"It's one thing to get the bill passed," Staks said. "It's another thing to actually get the thing off the ground. The implementation part still has to happen as well."

For example, the RO has yet to be incorporated, and the Launch Committee is still drafting the bylaws and policies that will guide the organization. Additionally, FERC must approve the tariff change, and the committee must seat a board and find an executive director.

All those tasks will take time and money.

The group, which has estimated a $7.1 million budget for all three of its phases, hit a financing snare early in 2025 when the Trump administration paused nearly $1 million in funding as part of a larger spending freeze on projects previously promised support by the Biden administration.

There is enough money in the bank to cover expenses through the end of 2025, but the committee needs roughly $2 million for 2026 and about $4.8 million for 2027, staff said during an Aug. 29 meeting.

The group has issued an updated pledge form and a draft funding agreement to solicit additional funding, and it also is considering debt financing as an option.

"Fundraising is not going to be easy," Staks said. "But I also think that, again, the economic benefits of getting this done and having one large, independently governed market for the West are good enough that we will be able to overcome that hurdle."

Keeping the Door Open

However, the West will, at least for now, have two day-ahead markets. Because in tandem with CAISO's EDAM, SPP is developing an alternative day-ahead market for the region — Markets+. SPP is also developing a Western version of its Eastern RTO called RTO West.

Major utilities like PacifiCorp, Portland General Electric and the Los Angeles

Department of Water and Power have committed to EDAM.

Meanwhile, entities such as Xcel Energy subsidiary Public Service Company of Colorado, El Paso Electric, Tacoma Power and the Bonneville Power Administration have agreed to join Markets+. (See *BPA Chooses Markets+ over EDAM*.)

Despite utilities committing to either EDAM or Markets+, Staks said there is still a possibility for a unified market in the West. Utilities could decide to leave the SPP option and instead join EDAM, which has a larger market footprint, Staks noted.

The success of AB 825 "keeps the door open" for creating a larger market in the West, and ultimately an RTO, she said.

The bill "crosses off one of the barriers that have existed for so long … for utilities to decide to join and to go further with a market that is governed by California," Staks added.

Supporters of EDAM have pointed to production cost studies by The Brattle Group and Energy and Environmental Economics that have found that CAISO's market option would save ratepayers millions of dollars more than Markets+. (See *Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW*.)

For example, an October Brattle study found that BPA would earn $65 million in annual benefits from EDAM but face $83 million in increased yearly costs from participating in Markets+.

BPA and other Markets+ supporters have argued the production cost models have limitations and cannot capture the full economic picture. Additionally, BPA staff have pointed to Markets+'s resource adequacy requirements, greenhouse gas accounting mechanisms and especially its independent governance model. (See *Western Utilities Set Sights on RTO After DAM Choice*.)

After AB 825 passed, BPA told *RTO Insider* that the bill is a "positive development toward a more equitable market landscape in the West," but maintained that Markets+ will provide greater benefits for its customers.

"While Bonneville participated in the development of several important provisions in the Pathways Initiative — like broader stakeholder engagement and the assurances for public purposes — BPA has been and remains clear in its desire to participate in a market wholly separate from the authority of any single state or entity," BPA said.

However, Staks noted that U.S. senators from Oregon and Washington, along with stakeholders in the region, urged BPA to wait for the Pathways Initiative to play out, which the agency did not do.

Citing stakeholder comments, Staks said, "If governance is such a problem, why wouldn't you wait for the Pathways Initiative, for the California legislative process to happen?" (See *BPA Flooded with Comments on Draft Day-ahead Market Decision*.)

"I think the response from BPA has generally been, 'yeah, we don't even think that the Step 2 proposal goes far enough, it's not independent enough,'" according to Staks. "I'm not even sure what to say to that."

"The new RO has sole authority over the EIM and EDAM," Staks contended. "I don't know how you get more independent than that."

She acknowledged the RO will initially be under CAISO's tariff, "and so there are some challenges inherent in that."

"But that does not mean that the governance over the market is not … fully independent, because it is, and that was the design," Staks said.

"We have that [independence] in Markets+, BPA spokesperson Kevin Wingert told *RTO Insider*. "Markets+ continues to demonstrate the effectiveness of its Western participant-led governance."

Scott Simms, executive director of the Portland, Ore.-based Public Power Council, which strongly urged BPA to join Markets+ throughout the agency's decision process, said the passage of AB 825 did not address the organization's concerns about EDAM's governance or affect its evaluation of the two options.

"PPC, and other Western entities including BPA, have been very clear about our concerns with the continued relationship between the future regional organization and CAISO under the Step 2 proposal, which prevents establishing truly independent governance over EDAM," Simms said in an email.

'Erosion of Trust'

The next steps for the Launch Committee include continuing to support the development of the RO until an independent board is brought on around July 2026. The board will not have power over markets until FERC approves the tariff, but it will assume authority over the RO to pick an executive director, negotiate the service agreement between CAISO and the RO and design the overall strategic plan for the RO moving forward.

The committee will continue to exist to support the board and make recommendations, "but ultimately, those decisions will be made by this independent entity starting next summer," according to Staks.

"Once we have the RO set up and it has the market authority, then the Pathways Initiative has been successful," Staks said. "And then we take a victory lap and see what else needs to be worked on."

The committee consists of representatives from all sectors in the Western power industry that have an interest in developing electricity markets in the region. Staks said the effort is a testament to the importance of collaboration.

She said the debate over EDAM and Markets+ has created an "erosion of trust" and forced people into camps.

"We have an opportunity now, and we have a mandate now to rebuild those relationships," Staks said. "Because whether we have one market or two, we're going to have to find a way to work together, because the challenges are too big for us to be divided."

The country faces "almost existential" challenges, Staks said. She pointed to difficulties of building new infrastructure, the changing generation mix, load growth and "inconsistent policies" coming out at the federal level that are targeting the renewable energy sector along with tariffs impacting supply chains. (See *IRS Guidance on Wind and Solar Credits Not as Bad as Feared*.)

"We have not just common ground, but universal agreement that we must be able to provide affordable, reliable energy to our consumers," Staks said. "Those are fundamental tenets for every state in the West. Those are not political issues. Affordability and reliability are imperatives. And if we can peel away the rest of this noise and come back to those two fundamental tenets, I think we've got a good platform to rebuild trust and relationships again." ■

Calif. Lawmakers Pass Bill to Accelerate Transmission Development

Sweeping Legislation Would also Boost Wildfire Fund by $18B

By Elaine Goodman

The California legislature has passed a bill that would create a "transmission accelerator" to develop low-cost public financing programs for certain transmission projects.

Senate Bill 254, by Sen. Josh Becker (D), would also establish an $18 billion "continuation account" for the state's wildfire fund to cover investor-owned utilities' wildfire liabilities. Contributions to the fund would be split between ratepayers and shareholders.

Lawmakers passed the bill Sept. 13 in the final hours of the 2025 legislative session. If signed by Gov. Gavin Newsom, the urgency measure would take effect immediately.

Becker said the bill, which was 361 pages, was the culmination of three processes. Elements of his initial bill were combined with consumer affordability measures developed in the state Assembly, as well as Gov. Gavin Newsom's proposal to shore up the state's wildfire fund.

During the Sept. 13 floor session, Senate President Pro Tem Mike McGuire thanked Becker for his perseverance on what he called one of the largest energy reform bills in state history.

"This bill has died about 10 times, and you've stuck through it," McGuire said.

Mike McGuire, president pro tem of the California Senate, urges his colleagues to vote for SB 254 on Sept. 13. | *California Senate*

Why This Matters

The huge energy bill tackles topics including transmission development, energization timelines and utility profits.

Becker pitched his bill as a way to rein in rising electric bills.

California investor-owned utilities' electric rates traditionally have been higher than the national average and are rising rapidly, a legislative analyst said in reviewing SB 254. Electric rates charged by Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) have risen by 127, 91 and 72%, respectively, over the last decade, the analyst said.

SB 254 "will save ratepayers billions, stabilize our utilities and make sure the grid can support housing, clean energy and economic growth," Becker said in a release.

One way the bill aims to save money is through a California Transmission Accelerator within the Governor's Office of Business and Economic Development. Eligible transmission projects could receive low-cost public financing through the California Infrastructure and Economic Development Bank.

The bill gives the accelerator a Dec. 31, 2026, deadline to coordinate transmission planning activity in the state "in order to minimize duplicative efforts" and increase efficiency.

The accelerator would review results of CAISO's transmission planning process and choose projects to be eligible for public financing. Projects must be consistent with the state's reliability and greenhouse gas policy objectives.

The applicant must have successfully completed a previous California transmission project.

Recipients would repay the loans to an accelerator revolving fund so the money could be used for other transmission projects.

The Transmission Accelerator appears to replace the Clean Energy Infrastructure Authority that was proposed in a previous version of the bill but was subsequently scrapped. (See *Calif. Bill Seeks to Control Electric Bills, Create Transmission Authority*.)

Wildfire Fund

California launched its wildfire fund in 2019; utilities may tap into it to pay claims for damages resulting from a wildfire caused by utility equipment. PG&E, SCE and SDG&E contribute to the fund, as do electric ratepayers.

Without the proposed continuation account, the state's wildfire fund could run dry due to claims from the 2025 Eaton fire in Southern California, a legislative analyst said.

Under SB 254, electric customers would pay into the continuation account through an existing charge on their bills, which is set to expire in 2035 but would be extended for 10 years.

Without the wildfire fund, Becker said, "ratepayers are on the hook for everything because of inverse condemnation," which holds utilities liable for all damage caused by their equipment regardless of a finding of negligence.

If the wildfire fund runs out, SB 254 would allow utilities to use ratepayer financing to cover any settled wildfire claims between Jan. 1, 2025, and the time the bill takes effect.

The passage of SB 254 follows Newsom's comments in August that he'd be working with lawmakers to boost the wildfire fund by $18 billion. (See *Gov. Newsom Proposes Additional $18B for Calif. Wildfire Fund*.)

Energization Timelines

Becker said the bill would add "teeth" to existing law regarding timelines for utilities to energize new customers.

Under current law, the California Public Utilities Commission sets reasonable average and maximum energization timelines. Customers may report delays.

SB 254 would require CPUC to draw up an enforcement policy for those timelines, including penalties, by Jan. 1, 2027. CPUC would also consider requiring utilities to have executive compensation incentives based on whether the utility is meeting energization timelines.

CPUC would also require utilities to hire a third-party auditor to review their energization practices.

In other provisions, the bill would block utilities from earning a profit on $6 billion in fire risk mitigation projects starting Jan. 1, 2026. It would also require more transparency into utility profits, so that consumer advocates and others can better gauge whether the profits are just and reasonable. ■

Newsom Signs Calif. Pathways Bill into Law

Continued from page 15

"This was an unparalleled coalition that we built this year: Environmental Defense Fund, NRDC, Environmental Voter [Project]," Becker said. "This year the Sierra Club supported it — they always opposed it in the past; labor, who always opposed in the past, came on board because of some of the protections built in, and companies and the Chamber of Commerce. People who usually don't agree on anything, agreed on this. There was still a lot of opposition, but that coalition helped us get it done."

Becker said there are three positive outcomes of the bill: lower costs, improved reliability, and an expanded grid.

"The Brattle Group and California Energy Commission has projected it'll be between $800 million and a billion dollars of savings a year to California directly." Becker said being able to cite the economic benefits of the Western Energy Imbalance Market for 10 years supported the case for the bill: "That's delivered over $7 billion of economic benefits, $2.2 billion directly to California."

Second, he said the changes brought about by the bill should improve everyday reliability and decrease reliance on the most polluting peaker plants. The result: a 53% reduction in greenhouse gas emissions in California. "Right now, we spend billions of dollars keeping natural gas peaker plants available to run a few hours a year; literally, a few hours a year. We're going to be able to use some of these highly polluting assets a little less frequently in California."

Finally, the expanded grid provides reliability through major weather events: "Especially in the era of climate change, you need a grid bigger than any one weather event. As [California Energy] Commissioner Siva Gunda always says, if we have a massive heat wave, as we did on Sept. 6, 2022, being able to trade with our neighbors can increase reliability."

In addition to AB 825, Newsom signed into law a measure aimed at extending California's cap-and-trade program through 2045. The revenues of the program will go toward funding, among other things, California's high-speed rail project.

Other measures signed include efforts to stabilize gas prices, funding for air quality monitoring programs and the continuation of studies related to California's greenhouse gas targets.

The governor also approved SB 254, a law that will create a "transmission accelerator" to develop low-cost public financing programs for certain transmission projects. The legislation also establishes an $18 billion "continuation account" for the state's wildfire fund to cover investor-owned utilities' wildfire liabilities. Contributions to the fund will be split between ratepayers and shareholders. (See related story *Calif. Lawmakers Pass Bill to Accelerate Transmission Development*.) ■

Dej Knuckey contributed to this article.

CPUC Shifts More Attention to DR with New Rulemaking

Commission also Approves SCE's Sale of 7 Hydroelectric Facilities, General Rate Case

By David Krause

The California Public Utilities Commission is preparing to overhaul its demand response programs, policies and data systems to ensure uniform DR standards statewide and better position the Golden State to meet its energy policy and emissions goals.

During a Sept. 18 voting meeting, the CPUC approved an *order instituting rulemaking* intended to improve the "consistency, predictability, reliability and cost effectiveness of demand response resources in California," the commission said in its decision approving the rulemaking.

The rulemaking seeks to:

- Update demand response "guiding principles" designed to align statewide policies around DR programs.
- Update policies related to the state's "dual participation" model, valuation methodologies and evaluation metrics.
- Standardize DR data system and process requirements.

Standardized data processes will help the commission reduce data costs and errors, staff said in their proposed decision.

The decision comes a few weeks after the commission approved guidelines for dynamic rate designs for the state's investor-owned utilities. (See *CPUC Approves Guidelines for Large IOUs' Dynamic Rate Designs*.)

"This is a big moment for demand response in California," Commissioner John Reynolds said during the voting meeting. "At our present moment, rates don't yet provide a clear signal to manage electric usage as efficiently as possible or desirable."

"I wouldn't be surprised if California one day reaches a point where most, if not all, demand response programs rely on economic signals that are integrated into existing retail and wholesale markets," Reynolds added.

In a presentation during the meeting, CPUC staff said demand response principles should be "predictable and reliable" so they can be incorporated into California's forecasting and planning frameworks.

Inconsistent or unpredictable demand response programs "jeopardize grid reliability, trigger emergency procurement of costly backup resources and erode confidence in the capability of demand response resources to play a significant role in achieving the state's energy and environmental goals," staff said in the presentation.

"Without furthering our demand response policies, it is my belief that we're not going to be able to meet our clean energy goals," Commissioner Darcie Houck said at the voting meeting. "These [upcoming] policies are going to be absolutely critical."

CPUC staff plan to publish a full proposal for the new rules in the first quarter of 2026, followed by commission vote in the third quarter.

SCE General Rate Case Revenue Approved

The commission also approved Southern California Edison's (SCE) test year 2025 *general rate case* that includes a total revenue requirement of $41.8 billion for 2025-2028.

The approved revenue requirement will increase average residential monthly bills by about $9.80 for California Alternate Rates for Energy (CARE) customers and $15.52 for non-CARE customers — a rise of about 9.1% for both groups.

A significant portion of the money in the rate case — about $3.1 billion — will be used for work that reduces wildfire risk in SCE's territory. SCE plans to spend about $554 million specifically on trimming and removing vegetation that is near electrical facilities to reduce the risk that those facilities start a fire.

Notable Quote

"I wouldn't be surprised if California one day reaches a point where most, if not all, demand response programs rely on economic signals that are integrated into existing retail and wholesale markets."

— Commissioner John Reynolds

"A large part of utility expenditures today have to do with wildfire mitigation, and this decision recognizes the need to target undergrounding of powerlines and also authorizes covered conductor projects, all of which will dramatically cut wildfire risks," CPUC President Alice Reynolds said at the meeting.

"[This decision] recognizes the importance of all of [SCE's] investments and costs, but [it] also [recognizes] the really urgent need to impose discipline on those costs, and that's just as important given the challenges that Californians are facing for cost of living," she added. "I think this decision does that. It's not easy. We can't find a perfect solution."

SCE Approved to Sell 7 Hydro Facilities

The commission also *approved* SCE's request to sell seven of its small hydroelectric facilities to the San Bernardino Valley Municipal Water District for about $34 million.

The facilities are Mill Creek 1, Mill Creek 3, Ontario 1, Ontario 2, Santa Ana River 1, Santa Ana River 3 and Sierra. Six of the seven facilities are operational and generate about 11.6 MW, or about 1% of SCE's total hydroelectric facility capacity of 1,164 MW.

SCE will incur a pre-tax loss of about $60 million due to the transaction, the decision says. ■

CAISO RA Initiative Moves Forward with 3 Proposals

But Concerns and Questions About Possible Changes Not Diminishing

By David Krause

CAISO is finalizing a set of changes to its resource adequacy program, with plans to vote on three proposals at an upcoming Board of Governors meeting, possibly as early as October.

The proposed RA program revisions are part of CAISO's RA Modeling and Program Design *initiative* that began in August 2023.

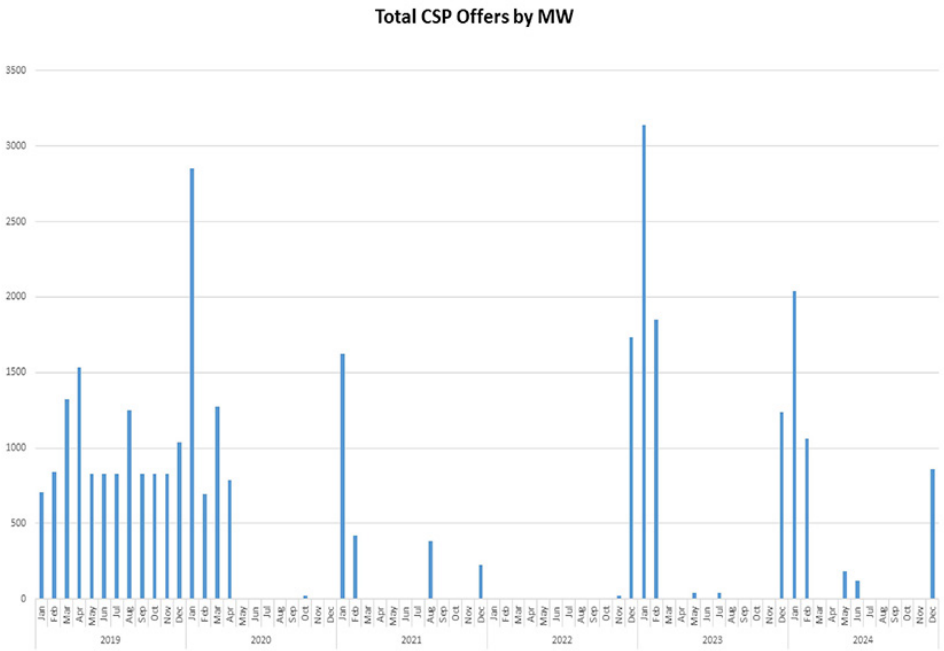
The first *proposal*, "Track 1: Modeling and Default Rules," which was published Aug. 25 and presented to stakeholders at a Sept. 17 workshop, updates certain requirements within CAISO's qualifying capacity (QC) methodology and planning reserve margin (PRM) process.

The proposal provides a default set of RA rules for local regulatory authorities (LRAs) — that is, publicly owned utilities — that have not established their own methodologies and processes. These RA rules can also be voluntarily adopted by any LRA within the CAISO balancing authority area, the proposal says.

CAISO is specifically looking to replace a "longstanding" default PRM requirement of 15% with a new margin that would be periodically determined based on loss of load expectation (LOLE) studies. The new PRM process would ensure a market participant's energy resource portfolio meets the industry-standard reliability benchmark of 0.1 LOLE when an LRA does not provide a QC methodology, the proposal says.

Stakeholders involved in the initiative questioned whether existing RA programs or CAISO's default RA rules for LRAs meet a 0.1 LOLE requirement.

Some LRAs said they rely on CAISO's default RA rules when developing their own requirements, but these rules have not been revisited or "significantly updated since they were established approximately 20 years ago," CAISO said in the proposal.



Capacity bid into CAISO's Competitive Solicitation Process from 2019-2024 | *CAISO*

Why This Matters

CAISO is updating critical parts of its resource adequacy program, including rules that have not been revisited in about 20 years.

In Sept. 12 comments to CAISO, representatives from the Alliance for Retail Energy Markets (AReM) said the group remains concerned about the differences between the CPUC and CAISO's modeling and market design requirements.

"While AReM recognizes that other LRAs are seeking single monthly default QC values in contrast to the California Public Utility Commission's slice-of-day paradigm, which adopts 24 hourly values for each resource each month, it is important all LRAs avoid using divergent methodologies," AReM said. "Unless CAISO can show its proposed methodology results in consistent outcomes with slice-of-day, it should not adopt its Track 1 proposal."

AReM also asked CAISO to provide greater clarity on how battery durations will be counted in CAISO's default QC counting rules.

"CAISO's proposal would, seemingly, lump all battery capacity together, including eight-hour batteries and four-hour batteries even though the CPUC has ordered LSEs under its jurisdiction to procure eight-hour duration storage resources and the CPUC's slice-of-day methodology assigns greater value to longer-duration battery resources," AReM said.

Track 2 Proposal

In the second *proposal*, published Aug. 26, CAISO pitched the formation of a new energy resource substitution "pool." The pool would allow a scheduling coordinator (SC) to signal when they need to procure substitute capacity because their energy resources are offline due to a planned outage. The substitution pool would also allow an SC to indicate when it is able to offer substitute capacity for other SCs.

Under current rules, CAISO requires an SC with a resource undergoing a planned outage to provide substitute capacity for that resource. However, securing substitute capacity can be difficult due to "mismatches between contract terms and outage durations, as well as inefficiencies in the bilateral procurement process," CAISO staff said in the proposal.

Additionally, multiple SCs "hold back RA capacity for outage substitution for a partial-month outage. This practice drives artificial tightness in the RA bilateral market," staff said.

The cost to procure replacement capacity can be greater than the cost to pay a non-availability penalty under CAISO's Resource Adequacy Availability Incentive Mechanism, staff added. This has led to forced outage rates going higher than those predicted by CAISO and the California Energy Commission.

The pooling approach would improve price certainty because buyers would be able to choose offers aligned with their willingness to pay.

It would also increase visibility into available supply, "giving buyers greater control over their choices and providing direct contact information for sellers." Benefits of the proposal include "enhance[d] flexibility, transparency and efficiency in managing planned outages," the proposal says.

On the other hand, SCs that have scheduled, immovable planned outages might want to continue arranging for substitute capacity outside of the proposed substitute pool process, the proposal says. Sellers might also face uncertainty depending on competing bids and might change their offer structure after seeing other postings in a pool, staff said.

Stakeholders such as the California Community Choice Association and the California Department of Water Resources supported the proposed pooling method.

The Track 2 proposal should be presented only to the CAISO Board of Governors for a decision because the initiative "falls outside the scope of authority of the Western Energy Markets Governing Body," ISO staff said in the proposal.

Track 3A Proposal

The initiative's "Track 3A: Resource Visibility" *proposal* is meant to improve CAISO's visibility into what resources are available for procurement through the ISO's backstop measures.

Better visibility into the status of RA-eligible capacity not shown as RA will "help the ISO conduct existing backstop processes more effectively and understand how any emerging trends should be incorporated into backstop program design," staff said in the proposal.

Backstop procurement helps CAISO find additional energy for the grid when there is a shortage of RA or if conditions require the grid to procure more energy than that supplied by the RA program, staff said.

Part of the problem has been that the number of bids into CAISO's Capacity Procurement Mechanism (CPM) has dropped significantly over the past five years. CPM is within CAISO's Competitive Solicitation Process (CSP), which is the primary process for identifying capacity available for CPM designation.

"Conducting efficient and effective backstop procurement requires understanding what capacity is still available after accounting for all RA-shown resources," CAISO staff said in the proposal. "The CSP is designed to provide this understanding."

In addition to reliability improvements, the increased visibility under Track 3A can "improve policy and modeling for the CAISO system," representatives with the CAISO Department of Market Monitoring (DMM) said in Sept. 16 comments on the initiative.

"Additional visibility into RA resources internal to the CAISO balancing authority area would improve a system-wide understanding of recent trends in the CPM and CSP, and potential improvements to the CPM," DMM said.

The Track 3A proposal specifically includes new annual and monthly reporting requirements for all RA-eligible capacity in CAISO that is not shown as RA, the proposal says. Implementing these reporting requirements could make it easier to see what resources are open for procurement within CAISO's backstop procurement program.

The proposal designates five categories of supply: supply that is sold outside the CAISO BAA; supply not shown due to being reserved for substitution; supply not shown due to potential unavailability; supply contracted to a CAISO LSE but not shown; and supply not contracted.

The new reporting requirements would apply to SCs that have RA capacity and are located inside the CAISO BAA that appears on the ISO's Net Qualifying Capacity list, the proposal says. Reporting will be part of CAISO's existing annual and monthly supply plan timeline requirements. ■

BPA Inks Agreement to Purchase Wave Energy

Agency Commits to Project off Oregon Coast

By Henrik Nilsson

The Bonneville Power Administration has entered into a five-year power purchase agreement to buy wave energy from a test facility managed by Oregon State University (OSU), the agency said.

BPA will buy up to 20 MW/hour of test energy output from the OSU-administered PacWave project starting in 2026 at a purchase price of 75% of the CAISO Western Energy Imbalance Market's index price, according to the *PPA* published Sept. 16.

Dan Hellin, PacWave's director, called the agreement "a significant milestone for PacWave and Oregon State University."

"We feel that it demonstrates the value of wave energy as an emerging renewable resource and provides a practical pathway for PacWave-generated electricity to enter the grid," Hellin told *RTO Insider*. "This agreement not only validates PacWave's role as a leading open-ocean wave energy test facility but also ensures that the technologies we host are evaluated under real-world market conditions — an essential step toward advancing wave energy from an experimental concept to commercial reality."

Funded by the U.S. Department of Energy and the state of Oregon, the agreement with BPA concerns one of two facilities currently under development by PacWave. The project is an open wave energy testing facility and sits seven miles off the coast of Oregon. The university submitted a small generator interconnection application in 2015, and BPA has partnered with OSU to ensure the project meets the requirements for new generation in the agency's balancing authority.

In March 2021, FERC issued a license for construction and operation of the wave project, and the facility was completed in early 2025, according to PacWave's website.

BPA has agreed to purchase energy at a delivery point within a Central Lincoln Public Utility District-owned distribution facility, according to the agreement.

Specifically, BPA entered the agreement under the Northwest Power Act's section on conservation and resource acquisition. The agency can acquire output under the section if the resource is not a major resource, is experimental, has the "potential" to provide cost-effective services, and if BPA has included the resource in its annual budget to Congress.

The project meets all four conditions, BPA stated, noting the agreement only covers 20 MW of energy per hour and that the project is intended to test the potential of wave energy.

"Because the wave energy industry is in its early stages, the reliability, availability and economics of the various wave energy converter technologies are currently uncertain," the agreement states. "The project will provide BPA, OSU and the project clients an opportunity to learn more about the operational characteristics and commercial feasibility of wave energy technologies, which will provide BPA with information regarding the industry's potential cost-effectiveness."

OSU will select four clients and provide "each with access to an offshore testing berth with a 5-MW-capable power and data cable connection to the shoreside grid connection facility," the agreement states.

The partners expect the project will begin generating in the spring of 2026.

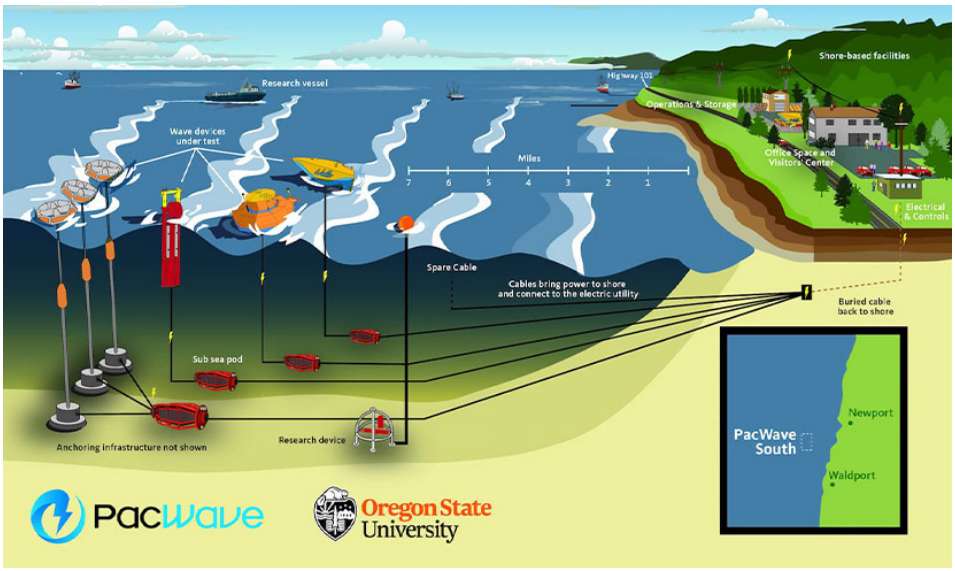
"This is a small resource purchase that makes economic sense for BPA customers and helps meet BPA's responsibility to foster emerging technologies in support of its strategic plan, regional and national energy goals," BPA said in an announcement.

Other states have also explored wave energy's potential. For example, in April, the California Energy Commission found that the Golden State has a significant amount of marine energy potential in the northern part of the state but much less in the south. (See *Calif. Report Examines Deep Potential for Wave Energy* and *CEC Report Shows High Ocean Energy Potential in Northern Calif., Less Down South*.)

In 2021, the Hawaii Natural Energy Institute announced it would receive $6 million from the Naval Facilities Engineering Command to research wave energy conversion technology. (See *Hawaii Wave Energy Project Gets $6M in US Navy Funding*.) ■

Why This Matters

The agreement suggests BPA believes the emerging wave energy industry could provide potential benefits to the agency's customers.



BPA has agreed to purchase wave energy from Oregon State University's PacWave project. | *PacWave*

Texas PUC Releases Rulemakings for Large Loads

Commission also Puts off Decision on Entergy 500-kV Tx Line

By Tom Kleckner

Texas regulators have proposed new rules on large load forecasting criteria and net metering following the state's recent biennial legislative session and opened them up to public comment.

The two projects are among four active dockets related to *Senate Bill 6*'s implementation. One of the state Senate's top priorities, the legislation, among other things, directed the Public Utility Commission to determine a cost allocation for large loads to ensure they're paying their fair share of infrastructure expenses. (See *Texas Bills Targeting Renewables Come up Short*.)

The PUC has *recommended* that to gather as much feedback as possible, the large-load criteria be standardized to include loads exceeding 25 MW. The criteria intentionally excludes loads below 25 MW, which primarily interconnect at the distribution level (*58480*).

PUC Chair Thomas Gleeson said during the commission's Sept. 18 open meeting that he has yet to agree projects should be included in ERCOT's load forecast if they meet a pair of criteria by submitting attestations to the transmission or distribution service provider. He asked stakeholders to comment on the benefits provided by submitting attestations that show "significant, verifiable progress" toward: 1) completion of required site-related studies and engineering services and 2) obtaining state and local regulatory approvals required before a project's energization.

"I'm going to need to be sold on having this in this rule going forward," he said.

The criteria will have an implication for ERCOT's *Regional Transmission Plan*, which begins in 2026.

The proposed *net-metering rulemaking* will apply to large loads and existing generation resources and establish the criteria for ERCOT' s study of the arrangements. It sets the procedural steps for staff to complete their study of a net-metering proposal within 120 days and the commission's procedure to approve, with or without conditions, or deny a net-metering proposal within 60 days after ERCOT files its study results and recommendations (*58479*).

Attorney Everett Britt lays out Entergy Texas' position on a proposed 500-kV transmission line. | *AdminMonitor*

ERCOT staff was on hand to *share details* of ERCOT's studies of the net-metering arrangements' reliability effects while the rule is being developed. They said the studies will evaluate the effects on transmission security, resource adequacy and the stranding or underuse of existing transmission facilities.

The analysis will consist of a before-and-after capacity reserve margin evaluation using ERCOT's most recent capacity, demand and reserves (CDR) report as a baseline. Reserve margin effects over the next five years will be reported for both the forecasted peak load hour and net load hour in line with the CDR reserve margin reporting requirements.

Participants in ERCOT's market have until Oct. 17 to file initial comments or request a public hearing. Reply comments are due by Oct. 31.

SETEX Reliability Project

The PUC once again delayed action on Entergy Texas' proposed 500-kV single-circuit transmission line in northeastern Texas after hearing oral arguments from more than a dozen landowners or their attorneys (*57648*).

Gleeson promised the commission would reach a decision on the transmission line during its Oct. 2 open meeting. The project has 61 proposed routes, with PUC staff and Gleeson each favoring different routes.

"As I sit here right now, I'm still not prepared to make a decision," he said. "I think it's appropriate to extend it one more meeting to take into account everything that was said and to make sure that anything we're considering from that oral argument is in the record."

The 150-mile SETEX Area Reliability Project has *drawn opposition* from local landowners, who requested a rehearing of the State Office of Administrative Hearings' *decision* to recommend a certificate of convenience and necessity for the line. The project's various routes range from 131 to 160 miles, and its costs are projected to be between $1.33 billion and $1.52 billion.

"Entergy Texas is sympathetic to the concerns landowners may have about the line," said attorney Everett Britt, representing Entergy. "Each of the 61 routing options before you satisfies the need for the project. It is viable and constructible. We've heard a number of arguments and issues raised today. We do think these have been addressed, if not by parties here today than in the extensive briefing and exceptions filed in this case." ■

Ontario Environmentalists Slam New Nuclear Units

By Rich Heidorn Jr.

Ontario environmental groups panned the Canadian government's inclusion of small modular reactors (SMRs) on its list of infrastructure projects to receive fast-track regulatory treatment, saying renewables would be a far cheaper way to expand generation capacity.

Prime Minister Mark Carney on Sept. 11 *identified* four SMRs planned at Ontario's Darlington nuclear power plant as one of five "nation building" projects he said are needed to bolster the country's economy in response to U.S. President Donald Trump's escalating tariffs.

Speaking at a union training facility in Edmonton, Carney *called* Trump's actions "not a transition [but] a rupture."

"They are closing markets, disrupting supply chains, halting investments and pushing up unemployment. Canadians are over the shock, but we must always remember the lessons," said Carney, who took office in March. "From now on, Canada's new government starts by asking ourselves, for major projects, 'how?' How can we do it bigger? How can we do it faster?"

The Canadian and Ontario governments have leapt ahead of other regions in embracing SMRs, touting their zero emissions and economic development potential. But environmentalists say the province would be better served by building more renewables and storage to fill electricity demand projected to grow by 75% by 2050.

"Ontario risks being left behind by failing to embrace the faster, cheaper, cleaner alternatives already powering economies around the world," Ontario Green Party Leader Mike Schreiner said in response to Carney's announcement. "Right now we could create good-paying jobs using Ontario steel to build steel racking for solar and wind turbines and generate low-cost power."

Tim Gray, executive director of Environmental Defence, and Jack Gibbons, chair of the Ontario Clean Air Alliance, were also critical.

Gibbons cited a recent analysis by IESO that he said showed that renewables and storage can meet the province's peaking and baseload demands at a far lower cost than SMRs.

Wind and solar power, combined with four-, six-, eight- and 10-hour lithium-ion batteries can meet up to 99.98% of the province's peaking electricity needs and up to 99.9% of its baseload needs under all weather scenarios, the alliance said in a *briefing note*. "Demand response resources and/or our existing gas-fired power plants could meet our remaining electricity needs," it added.

IESO's "*Resource & Plan Assessments Technical Paper: Hybrid Resource Portfolio Equivalency Assessment*" compared the capability and costs of portfolios of variable generation (VG) wind and solar and battery energy storage systems (BESS) — referred to as a "hybrid resource portfolio" — with combined-cycle gas turbines and SMR options.

Artist's conception of the Darlington New Nuclear Project, which would become the first operating small modular reactor (SMR) in a G7 country. | *GE Hitachi and Ontario Power Generation*

Why This Matters

OPG's Darlington project would become the first operating SMR in the G7, making its success crucial for the spread of the technology.

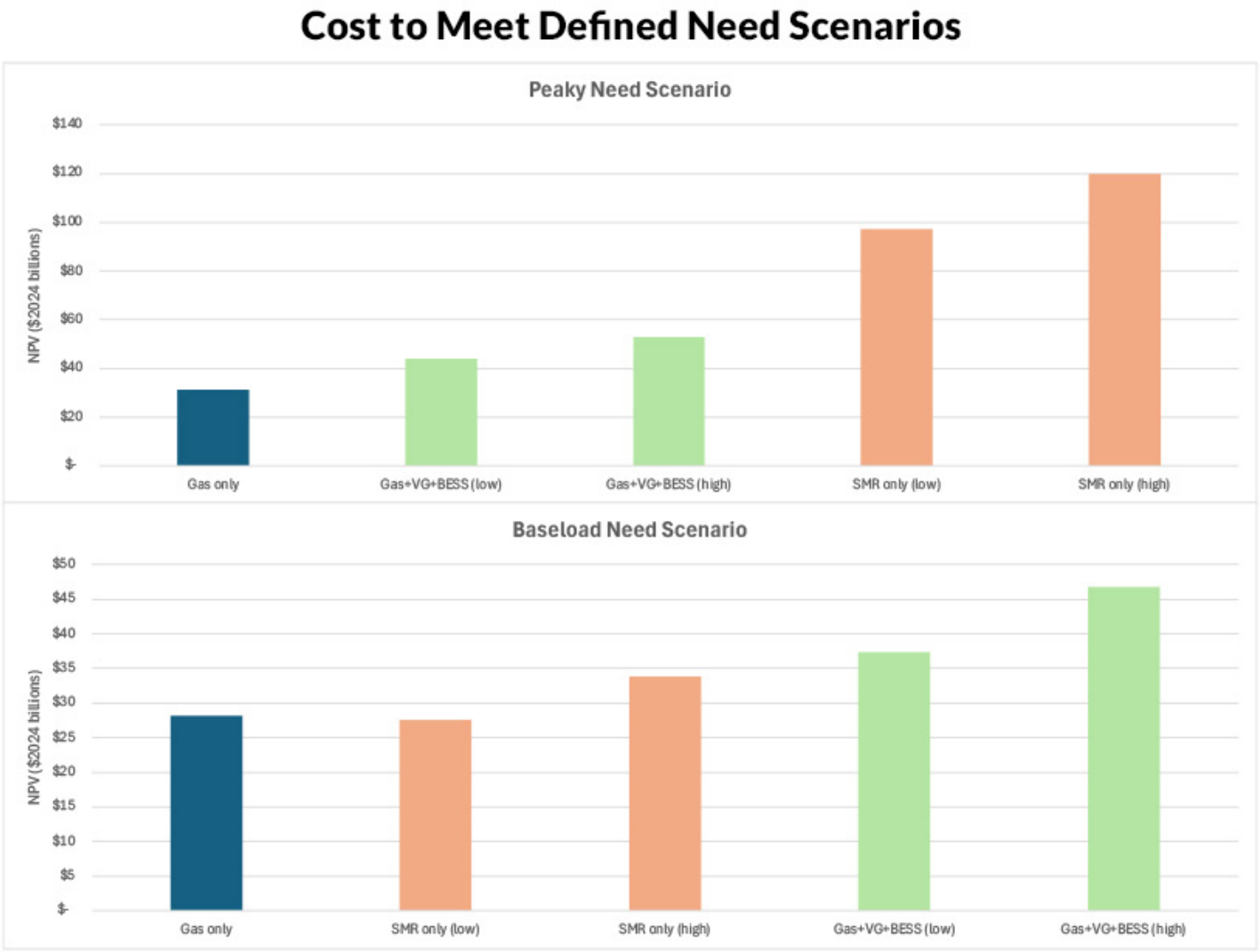
It concluded that a hybrid portfolio plus natural gas was the least-cost resource option to meet the 5.1-TWh Peaky Need Scenario, with a cost of $25 billion to $34 billion (net present value in 2024 Canadian dollars), depending on the weather year used. The gas-only option was estimated at $31 billion in seven of the 10 weather years. The Peaky Need Scenario is based on production cost modeling for the 2025 Annual Planning Outlook without capacity expansion, which resulted in unserved energy of about 5.1 TWh in the medium term and a peak need of about 7,300 MW.

The analysis found dispatchable resources were the best solution for the Baseload Need Scenario. "Both SMR-only and gas-only resource options have similar cost profiles when acting as a baseload generator," it said. The SMR-only option ranged from $27.6 billion to $33.8 billion, with the gas-only option estimated at $28 billion. The renewables-BESS option ranged from $37 billion to $47 billion depending on the weather year, a levelized cost of energy range of $140 to $175/MWh.

The Baseload Need Scenario assumes the addition of 2,000 MW of capacity, akin to a baseload generation facility, or 11,300 to 15,000 MW of installed capacity for the hybrid resource portfolio.

Hybrid Premium 'Smaller than Expected'

To capture the geographic and temporal ranges in wind speed and solar intensi-



The Peaky Need Scenario is based on production cost modeling for the 2025 Annual Planning Outlook without capacity expansion, which resulted in unserved energy of about 5.1 TWh in the medium term and a peak need of about 7,300 MW. The Baseload Need Scenario assumes the addition of 2,000 MW of capacity, akin to a baseload generation facility, or 11,300 to 15,000 MW of installed capacity for the hybrid resource portfolio. | *IESO*

ty, IESO's report considered 13 potential wind sites and 10 potential solar sites across 10 different weather years, assuming no transmission constraints.

"The premium on installed capacity and costs of hybrid resource portfolio solutions required to achieve load served up to 99.98% was smaller than expected," IESO said in the report. "As performance of VG and BESS technologies improves and costs continue to decline, a non-emitting, hybrid resource portfolio, in theory, shows significant promise. It can provide both baseload and peak nuclear generation."

'Excess Generation' Impact

The IESO analysis noted that wind and solar generation often need to be "overbuilt" to meet system adequacy needs and said that the value of the excess energy should "be considered in any planning study when comparing resource portfolios to meet a specific need."

The energy that would be curtailed as a result of the overbuild "could potentially provide tens of billions of dollars in system value" by displacing higher-cost resources, IESO said.

The Clean Air Alliance said that when the excess wind and solar energy is included ($17.8 billion in baseload scenarios, $28.4 billion in peaking scenarios), those sources and energy storage can meet peaking needs at a cost of $15.7 billion to $24.5 billion versus $97.1 billion to $120 billion for SMRs. Baseload electricity needs would be $19.5 billion to $29 billion for renewables and storage versus $27.6 billion to $33.8 billion for SMRs.

Questioning SMR Assumptions

The Alliance said IESO's analysis understated the cost difference because of overly optimistic assumptions regarding SMRs:

- IESO's capital cost estimates for new SMRs ($11,804 to $16,711/kW in 2024 Canadian dollars) are 25 to 50% lower than the cost of Plant Vogtle Units 3 and 4 in Georgia, which went into service in 2023 and 2024, respectively ($22,628/kW).
- IESO assumed the SMRs will have annual capacity utilization factors of 90.9%, well above the historical rates of Ontario's Pickering (71.4%) and Darlington Nuclear Stations (78.6%).
- Although Ontario Power Generation is spending $12.8 billion to refurbish Dar-

lington Nuclear Station after 26 years of service, IESO assumes the SMRs will operate for 60 years without major refurbishments.

IESO's report used the U.S. National Renewable Energy Laboratory's 2024 Electricity *Annual Technology Baseline* for the low end of the cost range and the Tennessee Valley Authority's 2025 *Integrated Resource Plan's* estimate of an "nth-of-a kind" light-water SMR for the high end.

OPG did not respond to a request for comment.

Not a Recommendation

IESO cautioned that its paper was a modeling exercise and did not consider any "resource build limits" such as supply chain issues that would impact the feasibility of building the resulting resource portfolios.

"It should be emphasized that this document is not a plan, nor does it constitute a recommendation or endorsement of any resource, resource portfolio or technology."

It also noted that to provide "high temporal granularity," its modeling used deterministic, hourly profiles that did not fully capture the dispatchability (e.g., gas turbines) and storage capability (e.g., hydroelectric reservoirs) of existing resources.

"The study also shows that Ontario would need to build more than five times the baseload need in total capacity in the hybrid scenario, and even then may still not be able to meet the full need," IESO said in response to questions from *RTO Insider*.

The ISO also noted that the paper did not consider the land use implications of the alternate portfolios. "A buildout of that scale would have considerable development and transmission costs that have not been factored into the paper."

Nonetheless, the ISO said the role of renewables and storage will increase, noting that it recently completed the largest battery storage procurement ever in Canada, and that renewables are eligible in its second long-term energy and capacity procurement. (See *IESO Officials Deny Favoring Gas Resources in Upcoming Procurement*.)

"Ultimately, Ontario's electricity grid benefits from a diverse supply mix that includes wind, solar, hydro, natural gas, nuclear and energy storage to keep the lights on," IESO said. "These different resources have different characteristics and responses to weather, and maintaining a diverse supply mix means we always have resources to draw on that are right for the moment."

Canadian Prime Minister Mark Carney announces Ontario's small modular reactors will receive fast-track regulatory treatment. | *CPAC*

The ISO said it plans to seek feedback on the study and rerun the simulation based on updated need profiles.

Ontario Pols Tout Economic Development Potential of New Nuclear

Ontario's first-ever integrated energy plan, *Energy for Generations*, endorses an "all of the above" approach to fuel diversity with an emphasis on retaining and expanding nuclear power and natural gas. (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

Ontario Premier Doug Ford in May approved OPG's plan to start construction on the first of four SMRs.

The initial 300-MW SMR, targeted for commercial operation in 2030, would be the first grid-scale SMR in the Group of Seven countries. OPG says building all four SMRs, a total of 1,200 MW, will cost $20.9 billion. (See *Ontario Greenlights OPG to Build Small Modular Reactor*.)

The Ontario government also is supporting the addition of up to 4,800 MW of additional nuclear capacity at the Bruce Nuclear Generating Station.

In a high electrification scenario, IESO says, the province could need up to 17,800 MW of new nuclear generation in addition to its current 12,000 MW, which generates more than half of the province's electricity.

Carney said the SMR in Clarington will "sustain" 3,700 jobs annually, including 18,000 during construction.

Officials also see their leadership on SMRs having additional economic impact, citing agreements to work with Saskatchewan, New Brunswick and Alberta on the technology.

"We are already seeing results," Clarington Mayor Adrian Foster *told* the *Toronto Star*. "Today, we have a Dutch delegation in town. [Other countries] are coming to see the SMRs. The world is paying attention to what is happening right here, right now."

Major Projects Office

In addition to the Ontario SMRs, Carney's five "nation building" projects include one to double the export capacity of the LNG Canada facility in Kitimat, B.C.; an expansion of the Contrecoeur Terminal at the Port of Montreal; a copper mine in Saskatchewan; and the expansion of the Red Chris copper and gold mine in northwestern British Columbia.

The five will be referred to the new *Major Projects Office* (MPO), which was created under the *Building Canada Act*.

Carney said the office also will help other, less advanced projects, including the 60-GW Wind West Atlantic Energy Project off Nova Scotia and the Pathways carbon capture project in Alberta.

Environmental Defence's Gray *panned* Carney's selection of the Kitimat LNG facility and the mining projects.

"The federal government promised Canadians that nation building projects would align with our climate goals. This announcement, which begins with the expansion of LNG Canada that will increase climate pollution, is completely inconsistent with this commitment and will threaten Canada's ability to meet its climate pollution-reduction targets," Gray said.

He called the carbon capture and storage project "deeply flawed and regressive."

"Carbon capture and storage has a decades long record of failure, delivering only a fraction of promised production emission reductions while locking Canada into higher overall oil emissions and draining public funds," he said. ■

FERC: New England TOs Must Disclose More Info on Asset Upgrades

By Jon Lamson

Eight New England transmission companies must provide the Maine Office of Public Advocate with more information on asset condition projects placed in service in 2022, FERC has ruled.

The ruling partly granted a formal challenge by the OPA alleging the eight transmission companies, including subsidiaries of Eversource Energy, National Grid, Avangrid and PPL, along with Vermont Transco, "refused to answer questions regarding investment policies and practices related to prudence of these investments" (*ER20-2054*).

Commissioner Judy Chang wrote in a concurrence that the Sept. 18 order "should serve as a call to action for transmission owners across the country to provide greater transparency regarding their transmission investments."

Asset condition spending has been a major focus for New England consumer advocates in recent years as costs associated with upgrades to existing transmission infrastructure have skyrocketed.

Although there is broad consensus that significant investments are needed to maintain and upgrade the region's aging grid, state representatives and consumer advocates have expressed concern about a lack of transparency and oversight over these investments. ISO-NE recently agreed to take on a non-regulatory role in reviewing asset condition project proposals. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

The OPA's formal challenge stems from a series of questions the office submitted to the companies in September 2023 seeking information on how the companies evaluated asset condition needs, considered solutions and alternatives, and determined when to proceed with projects.

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Why This Matters

The ruling affirms consumer advocates' access to information from transmission owners that could be used to challenge asset condition investments.

The OPA wrote in its challenge that the transmission companies violated the formula rate protocols by failing to adequately respond to the information request.

Consumer advocates from Massachusetts, Connecticut, New Hampshire and Rhode Island supported the OPA's challenge and emphasized the importance of information requests for providing consumers with the information needed to evaluate — and potentially challenge — the prudence of transmission investments.

The consumer advocates encouraged FERC to "interpret the [formula rate protocols] liberally and to issue a decision in this matter that fosters open and transparent exchange of information that will allow interested parties to evaluate and determine whether formula rate costs are reasonable and were prudently incurred."

In a joint response to the OPA's challenge, the transmission companies argued that the OPA filing does not meet the requirements for a formal challenge, that the OPA's challenge is based on many "inaccurate or false" claims and that the companies "did provide responses and supporting documentation in response to Maine OPA's information and document requests, in addition to objecting to certain questions."

The companies asked FERC to reject the challenge, writing that "failure to do so would invite needless litigation and divert resources away from the ongoing New England stakeholder process on transparency enhancements to the transmission regional planning process for asset

condition projects."

In its ruling, FERC directed the companies to provide more information in response to several of the OPA's requests, while finding some of the requests to be outside the scope of the companies' requirements under the protocols.

"We find that most of Maine OPA's questions clearly set forth the request for information in a manner such that identified NETOs [New England transmission owners] could make a good faith effort to answer those questions as required by the protocols," FERC wrote.

The commission found the OPA's requests for the identities of individuals involved in asset condition decisions and those seeking an undefined number of documents to be outside the scope of the companies' requirements.

FERC also found that, to varying degrees, the companies adequately responded to some of the questions, including the request that the companies describe their procedures for evaluating project alternatives.

However, FERC ruled that the companies did not adequately explain how they ensure projects are not placed in service before they are needed.

The commission also found that subsidiaries or Eversource, National Grid and Avangrid failed to make a "good faith effort" to document their procedures for evaluating asset condition needs or disclose whether any employee or consultant "recommended against proceeding with a particular asset condition project."

"This refusal to provide information that is reasonably necessary to determine the prudence of actual costs and expenditures included in the 2023 Annual Update could preclude Maine OPA from ever raising a prudence challenge by denying it the information required to raise serious doubt," FERC wrote.

It directed the transmission companies to provide more information correcting the deficient answers within 30 days.

In her concurrence, Commissioner Chang emphasized the importance of transparency regarding transmission investments, along with stakeholders' "fundamental right to transmission planning and investment information through existing formula rate protocols."

"At a time of sharply rising customer bills and increasing concern about the prudence of transmission planning decisions, transmission owners have an obligation to address those concerns and help customers, state regulators and stakeholders better understand how their money is being spent," Chang said.

She advocated for more standardization disclosures around transmission investments throughout the country and encouraged stakeholders to collaborate to develop these structures.

"If further action by the commission is needed to ensure customers have access to information needed to assess the prudence of transmission owners' investments, I encourage parties to bring the issue to the commission, as Maine OPA has done in this case," Chang wrote. ■

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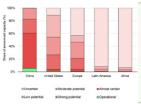

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Renewables Creating Opportunities for Pumped Hydro in New England

States Need Dispatchable (Clean) Power to Balance Growth of Intermittent Resources

By Jon Lamson

As decarbonization policy and the growth of intermittent renewable power in New England drives increasing needs for clean balancing resources, a developer in Maine is evaluating whether pumped storage hydropower — one of the oldest generation technologies still used in the region — could play an increased role in the grid of the future.

The history of pumped storage dates back about 100 years in New England. The Rocky River facility, which remains in operation today in western Connecticut, was the first of its kind in the U.S. when it came online in 1929. It was built to help balance the variable production profile of run-of-river hydropower.

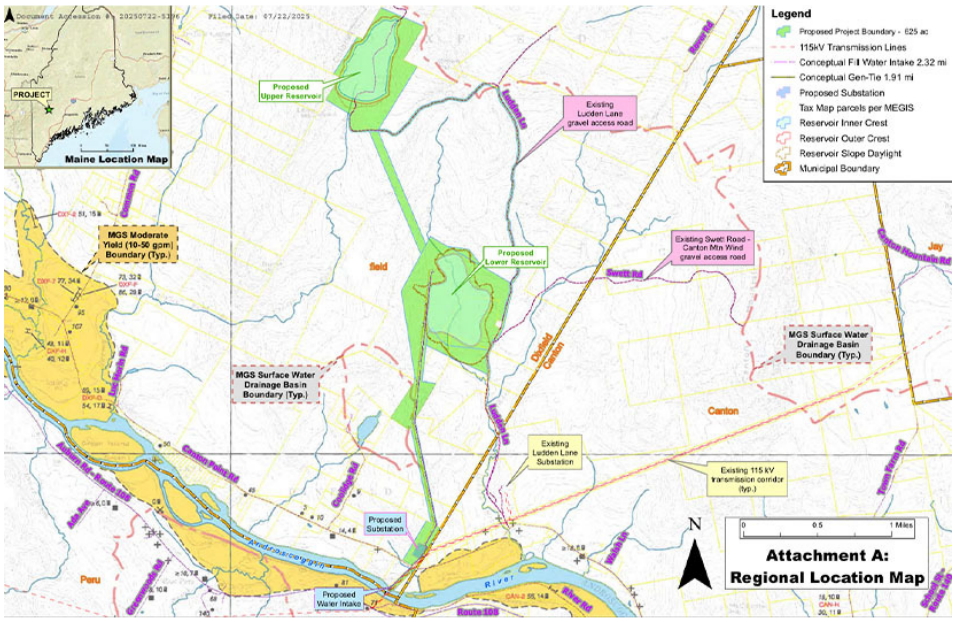
The facility is based on a simple concept: During periods of low-cost power, two 3.5-MW reversible pump turbines push water from the river to a large reservoir at a higher elevation. When power demand peaks, water flows downhill to produce power through the two turbines and a larger conventional generator.

In the 1960s and 1970s, the proliferation of nuclear power in New England spurred the development of two significantly larger pumped storage facilities in Western Massachusetts.

Northfield Mountain, which currently has 1,168 MW of qualified capacity with ISO-NE, and the Bear Swamp Generating Station, which has 662 MW of capacity, were built by utilities to help match the production profile of the nuclear resources with demand, allowing the nuclear plants to stay online at a constant level. The pumped storage facilities charged during low-demand periods at night and discharged during peak load periods in the day.

Why This Matters

Pumped storage may be able to help address New England's looming need for resources to balance the production profile of renewables, but significant barriers remain to new development.



Map of the proposed Western Maine Energy Storage pumped storage project | *Western Maine Energy Storage*

The facilities are both open-loop systems, pumping water from rivers to elevated reservoirs. They use large reversible pump turbines that are about 30% less efficient when pumping water uphill than when generating.

In the 50 years since the two plants came online, all but two nuclear plants in New England have been decommissioned, but Northfield Mountain and Bear Swamp remain in service.

"The economics of the projects really haven't changed. You're still looking for that price arbitrage: We're going to try to pump when prices are low, and we're going to turn around and generate when prices are higher," said Justin Trudell, CEO of FirstLight Power, which owns and operates the Rocky River and Northfield Mountain facilities. Trudell previously worked at Brookfield Renewable, which co-owns Bear Swamp.

To recover the costs of pumping water, "you've got to at least make up that 30-ish-percent loss of efficiency in that price arbitrage; that would set your baseline," Trudell said.

He added that, over the past decade, the steady increase of solar generation has caused the typical temporal pattern of pumping and discharging to shift.

"On sunny days, especially in the summer, we're seeing deep troughs in pricing midday when you have this glut of solar online," Trudell said. "We're seeing a lot more opportunities now where we're actually pumping during the day, and we're generally generating during the evening peak."

Growing behind-the-meter solar generation has contributed to an increasing difference between midday and evening demand. The RTO recorded a record-low demand around 2 p.m. on Easter Sunday in April, and about two months later, it recorded its highest load in over a decade around 7 p.m. on June 24. (See *Growth of BTM Solar Drives Record-low Demand in ISO-NE* and *Extreme Heat Triggers Capacity Deficiency in New England*.)

New Development Possibilities

With the growth of intermittent renew-

ables poised to continue in New England because of clean energy policies, increasing power demand and the challenges of fossil development in the region, states are looking to procure significant amounts of new storage capacity.

Connecticut has set a goal of deploying 1,000 MW of storage by 2030, while Massachusetts in 2024 passed legislation aiming to procure 5,000 MW of energy storage by mid-2030, broken into mid-duration, long-duration and multiday categories.

Western Maine Energy Storage, a company backed by construction corporation Cianbro, is investigating whether new pumped storage facilities could help meet this storage need, and in July it submitted a preliminary permit application for a 400- to 500-MW project in Dixfield (*P-15410*).

The proposed reservoir system would effectively function as a closed-loop system, featuring two 100-acre reservoirs at different elevations.

This design may help the project avoid some of the environmental challenges associated with open-loop pumped storage facilities connected to river systems. Both Northfield Mountain and Bear Swamp are involved in extended relicensing proceedings with FERC and have drawn criticism and opposition from environmental groups over impacts on downstream ecosystems.

Western Maine spokesperson Tom Brennan said the project is motivated by the increasing arbitrage opportunities brought by renewable production in the region. He highlighted Maine's goal of achieving 100% clean power by 2040.

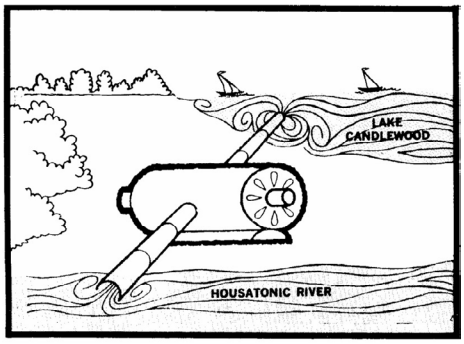
"If we're going to do that, we're going to need storage," Brennan said.

He said the company has been evaluating potential sites for a pumped storage project "for many years," adding that "Maine is, in many ways, ideal because of the topography variation."

"It's because of that topographic variation and access to a significant and appropriate transmission line that has us focused in on Dixfield," he said.

Unique Characteristics

Compared to lithium-ion batteries, pumped storage resources typically have a longer duration, though they rarely discharge to the point of depletion. Northfield Mountain has a *duration* of nearly eight hours, while Bear Swamp has a *duration* of about 4.5 hours.



1980 illustration of the Rocky River pumped storage system | *The American Society of Mechanical Engineers*

Both facilities also tout their ability to ramp up from no output to full output within about 10 minutes.

"We're faster[-ramping] than gas, and we're longer-duration than most batteries," FirstLight's Trudell said. "We're in this sweet spot of being able to provide more of a service for a longer period of time than some of these other technologies."

Trudell said Northfield Mountain relies primarily on revenues from the ISO-NE wholesale markets and is often held in reserve by the RTO as a first contingency. He emphasized the reliability benefits of the facility's ability to quickly ramp up or down as needed.

As ISO-NE works to overhaul its methodology for accrediting resources in its capacity market, storage owners have pushed for the RTO to account for ramp-up time in its accreditation methodology, and the storage industry is closely following the accreditation project to see how the changes could affect future capacity market revenues. (See *ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes*.)

State revenues are generally not a major revenue source for existing pumped storage resources; while Massachusetts' Clean Peak Energy Standard does not exclude pumped storage resources from generating Clean Peak Energy Certificates, resources that came online prior to 2019 are not *eligible*. Bear Swamp, which underwent an upgrade after this deadline, has qualified about 88 MW of its capacity in the program.

In July, Massachusetts issued a *procurement* of 1,500 MW of mid-duration storage, seeking to buy environmental attributes including Clean Peak certificates. (See *Massachusetts Seeks 1,500 MW of Mid-duration Energy Storage*.) Bear Swamp *bid* its full 88 MW of Clean Peak-qualified capacity for the procurement on Sept. 10.

'Who's Going to Buy the Power?'

By nature, pumped storage projects are very capital intensive, and any new facility would likely need a significant amount of revenue certainty for investors to commit to a project.

"The question is offtake, and you've got to get offtake before you get financing," Trudell said. "We know how to license, from the federal side, a new pumped storage project. The problem is: Who's going to buy the power?"

Connor Nelson, manager of regulatory affairs and markets at the National Hydropower Association, noted that there has been no new pumped storage built in the U.S. in about 30 years, in part because of these barriers.

"What you have is a long-lead-time, capital-intensive resource," Nelson said. "You need patient capital, patient investment, and you need, in a lot of cases, some sort of long-term capacity contract or a strong market signal that can assure developers and investors that this is going to be worth it in the long run."

However, he stressed that there is an "ever increasing need for long-duration energy storage" and said the "prospects for pumped hydro are as good as they've ever been, in part because there's a lot of good federal incentives right now."

He noted that the recent federal reconciliation bill did not strip incentives for pumped storage resources, and developers that begin construction by 2033 could get "upwards of 30% of that investment back in the form of a tax credit or direct pay if you're a utility."

Western Maine's Brennan declined to comment on the type of contracts or revenue certainty the company would need to move forward on the Dixfield project.

"We are so early in the process," Brennan said. "I am very short on details at this point; the design details will be in the works for some time to come." ■

New England Energy Experts Talk Renewable Development Under Trump

Raab Roundtable Contemplates Impact of OBBBA, Halting of Revolution Wind

By Jon Lamson

BOSTON — Energy experts and officials stressed the importance of proactive transmission planning, interconnection reform and increased demand-side flexibility at Raab Associates' New England Electricity Restructuring Roundtable on Sept. 19.

Speakers at the event reflected on the challenges the One Big Beautiful Bill Act (OBBBA) and the Trump administration's executive actions have created for clean energy development in New England, but they generally expressed optimism around the region's ability to withstand the federal headwinds.

"There will be pain, there will be companies that close, there will be less deployment as a result of the changes at the federal level," said Nathan Phelps, managing director of regulatory advocacy at Vote Solar.

However, "solar will not fall off a cliff" because "the price of solar has come down a lot, and it continues to be an attractive investment," Phelps said.

The OBBBA dramatically expedites the expiration of federal tax credits for wind and solar developers, and new projects must either begin construction by July 5, 2026, or come online by Dec. 31, 2027, to qualify for the full tax credits established by the Inflation Reduction Act. (See *U.S. Clean Energy Sector Faces Cuts and Limitations*.)

Why This Matters

New England's interconnection queue is made up almost entirely of renewable energy resources, and the region will likely be heavily reliant on new renewables and storage to meet load growth and decarbonization goals over the next decade.

Moderator Janet Gail Besser addresses New England Electricity Restructuring Roundtable attendees. | © RTO Insider

In New England, the looming tax credit phaseout has caused a mad dash for solar developers to try to lock in credits for later-stage projects, which may boost development in the short-term. Meanwhile, projects unable to begin construction in time for the deadlines will likely face increased risks of cancellation or major delay.

While the longer-term effects of the shift in federal policy are less clear, the Trump administration's antagonism toward offshore wind in particular threatens to undermine the buildout of a strong regional supply chain and workforce, which could have effects extending well beyond Trump's second term. (See *Tax Credit Phaseout Threatens Projects, Jobs in New England*.)

In the wake of the Trump administration's stop-work order on Revolution Wind, "it's really hard to have any confidence around what we can expect from the federal level," Phelps said.

Alicia Barton, CEO of Vineyard Offshore, emphasized the importance of offshore wind for meeting load growth in the coming decades.

"I don't think we have a choice — the region needs offshore wind," Barton said.

She declined to comment on the halt on Revolution Wind, which is being developed by Ørsted, but said Vineyard Wind, which is being developed by Vineyard Offshore and Avangrid, still aims to achieve commercial operations by the end of the year.

"We are still constructing, we are still moving forward," Barton said, adding that Vineyard Wind has created 3,400 jobs, including 1,400 union jobs.

On Sept. 22, after the roundtable, a U.S. District Court judge issued an injunction allowing construction to resume on Revolution Wind. (See *Judge Lifts BOEM's Stop-work Order on Revolution Wind*.)

Interconnection Reform

Speakers also discussed how reducing

From left: Digaunto Chatterjee, Eversource; Caitlin Marquis, Advanced Energy United; Rob Gramlich, Grid Strategies LLC; Mike Judge, Massachusetts Executive Office of Energy and Environmental Affairs; Janet Gail Besser, moderator | © *RTO Insider*

the soft costs of renewable development — including costs and delays associated with siting, permitting and interconnection — could help mitigate the effects of federal policy changes.

On interconnection, "the most important near-term thing is implementation of Order 2023," said Caitlin Marquis, managing director at Advanced Energy United.

FERC Order 2023 requires transmission operators to adopt first-ready, first-served cluster processes for interconnection. ISO-NE's first cluster study under the new rules will begin in October.

"ISO-NE deserves a lot of credit for holding a robust stakeholder process to implement Order 2023," Marquis said, while emphasizing that interconnection reform must go further than Order 2023 compliance to better integrate interconnection planning into the transmission planning process.

Marquis also highlighted the potential benefits of processes that allow new resources to share interconnection service with existing ones. She noted that ISO-NE has a surplus interconnection service option in its tariff but said stakeholders are seeking more flexibility.

At the state level, the administration of Massachusetts Gov. Maura Healey (D) has "made good strides" toward a more proactive approach for resource interconnection but is seeking to "consolidate some of the siloed processes into a more comprehensive planning process," said Michael Judge, undersecretary at the Massachusetts Executive Office of Energy and Environmental Affairs.

He said state officials are hoping to replace the Capital Investment Project process, a provisional program intended to enable fixed distribution interconnection costs, with a proactive interconnection planning process incorporated into the utilities' five-year electric-sector modernization plans.

Rob Gramlich, president of Grid Strategies, praised increased transmission planning initiatives taking place across New England. He noted that ISO-NE rated poorly in a pre-Order 2023 interconnection "report card" but said the Order 2023 compliance changes should help address some of the issues. (See *Transmission Report Card Grades MISO 'B,' Southeast 'F'*.)

"Transmission planning is the key solution here," he said.

Demand Response

Multiple speakers stressed the need to focus on demand response and flexibility.

For policymakers looking to decarbonize at the lowest possible cost, "one resource is way more important than all the others, and that's the demand side," said Paul Hibbard, principal at the Analysis Group and former chair of the Massachusetts Department of Public Utilities.

Hibbard said unlocking the full potential of demand response will require "fundamental changes" to rate design and programmatic spending.

"The technological hurdle to this is not a big one, it's really getting the price incentives up and running and the infrastructure in place," he said, adding that states must begin this work as soon as possible given the "painfully slow" pace of ratemaking.

Massachusetts' electric utilities are aiming to finish deploying advanced metering infrastructure across their service territories by the end of the decade, which should enable increased retail price incentives to reduce demand during peak periods.

"Electrification depends on it, affordability depends on it, and ultimately the commonwealth's decarbonization policy depends on it," Hibbard said. ■

MISO Board Orders More Detail into Monitor's 2026 Budget

By Amanda Durish Cook

DETROIT — MISO's Board of Directors has asked the RTO's Independent Market Monitor to better explain its $10.6 million 2026 budget before it agrees to the amount.

During Board Week, members of the board's Markets Committee said they wanted greater detail on a $5.9 million budget *item* the Monitor proposed for "base monitoring and data management tasks."

Monitor David Patton said "base monitoring" includes screening MISO market activity, data management, reviewing market outcomes and operations, producing reports, and coordination with the RTO. However, he did not allocate specific costs for each of the responsibilities.

Patton said the tasks take up a large share of the monitoring budget because that is his primary responsibility.

Director Robert Lurie said he would not accept a similar level of vagueness in MISO's proposed budgets. Director Theresa Wise similarly asked for more "visibility" into the budget.

Director H.B. "Trip" Doggett encouraged Patton to "polish it up" and bring the budget back to a nonpublic meeting with the board in October. The board and the Monitor could then present the final product during the next Board Week in December.

Wisconsin Public Service Commissioner Marcus Hawkins said he had "concerns with the timing of the additional scrutiny" into the Monitor's budget. He said that while he supported efforts into transparency, this year's heightened examination appeared suspicious because of the recent controversy surrounding the Monitor assessing MISO's transmission planning. (See *FERC Sides with Market Monitor over MISO in Compensation Dispute* and *MISO IMM Contends he Should Have Role in Tx Planning Oversight*.)

Hawkins said the IMM's budget increase in 2026 appears lower than the national rate of inflation. He asked board members to share the results of their nonpublic meeting in October at the next Board Week in early December.

Over 2024, the Monitor operated with a nearly $10.2 million budget. ■

The MISO Markets Committee of the Board of Directors in session on Sept. 16 at the Westin Book Cadillac hotel in Detroit | *© RTO Insider*

MISO IMM: Capacity Prices Efficient Despite Yearslong Error

By Amanda Durish Cook

DETROIT — MISO's Independent Market Monitor said the recently uncovered, eight-year-old repeat error in the RTO's capacity market that caused a $280 million impact in this year's auction alone is unfortunate but insisted the resulting prices were efficient.

Monitor David Patton said he thought the MISO tariff's requirement that loss-of-load expectation (LOLE) only be contemplated during daily peak hours was outdated in the first place. He said renewable resources have shifted loss-of-load risk to MISO's non-peak hours.

MISO discovered in summer that an unnamed vendor since 2017 has miscalculated the RTO's LOLE using an "all-hours" methodology, rather than the tariff-defined "daily peak hour" methodology, leading this year's auction to clear more capacity than intended. As currently defined, a day with a loss-of-load event is counted in MISO's LOLE calculations only if the event happens during the hour with daily peak load. The coding error caused a $280 million impact on market participants in this year's auction, with some owing more money and some getting refunds. (See *MISO Discloses $280M Error, Over-procurement in 2025/26 Capacity Auction*.)

Patton said that despite the mistake,

Why This Matters

MISO Independent Market Monitor David Patton said an eight-year-old loss-of-load expectation software error might have been a blessing in disguise because it kept the footprint functioning at the one-day-in-10-years standard and produced efficient capacity prices in the auctions. He lamented MISO's retroactive settlement adjustments.

MISO Senior Vice President Todd Ramey (left) and Monitor David Patton | © RTO Insider

MISO's clearing prices denoted the true reliability value of capacity resources in the footprint.

"The prices are actually right from a reliability standard; they represent a true one-day-in-10 standard," Patton told the Markets Committee of the Board of Directors, meeting during MISO Board Week on Sept. 16. "Unfortunately, the tariff is actually flawed."

MISO entered summer with a $666.50/MW-day capacity price across all zones. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.) The RTO experienced average real-time prices of $48.55/MWh over the summer, a 56% increase over summer 2024. The Monitor said energy prices rose largely from a 49% increase in gas prices and a 2% increase in load.

Patton said having an LOLE limited to peak hours "made sense six to seven years ago" when MISO had fewer intermittent resources and risk hours. He said the RTO's performance since then clearly shows that emergencies now crop up outside of the peak hour.

If MISO had set reserve margin targets and procured capacity according to a "daily peak hour" methodology, it would have only achieved a less than one-day-in-five-years loss-of-load standard, under half of the target, Patton said.

"I don't think it's the right answer, and MISO doesn't think it's the right answer either, as they have already filed to fix this," Patton said of the existing tariff language.

MISO said it plans to adopt an all-hours calculation in its LOLE because of its more volatile risk profile and emergency conditions popping up at non-peak times. However, the RTO did not mean to impose the switch beginning in the 2018/19 planning year.

Patton said that he was encouraged to see that MISO already filed to "fix the LOLE definition in the tariff with little opposition from participants."

Senior Vice President of Markets Todd Ramey agreed with the Monitor that the mistake resulted in a "more accurate representation" of day-to-day risk in MISO, though it "slightly overstated" risk according to tariff definitions. He explained to the board that the error affected a parameter in MISO's LOLE calculation, which "had an effect of being at odds" with the tariff-defined LOLE calculation.

Patton said that while the resettlements may be legally required, they "undermine the integrity of the competitive markets." He said resettlements will be "inconsistent with the information posted prior to the auction," which market participants used to make decisions regarding supply contracts and resource retirements. "From a market standpoint, this is really unfortunate," he said. He emphasized that it is critical that market participants can rely on the data MISO posts ahead of the auction.

Considering the tariff requirement that the RTO limit corrections on long-term errors to the past year, Ramey said MISO determined that the most "appropriate adjustment" was to resettle market participants' positions at lower estimated capacity prices in the 2025/26 auction.

MISO has said it will not rerun or completely resettle the 2025/26 auction. It has called the process "settlement adjustments."

Ramey said that because the auction clearing prices were the highest in summer ($666.50/MW-day), the "bulk" of financial impacts involve the summer. He said MISO would issue three separate settlement batches for the summer.

The RTO has held one-on-one meetings with affected market participants, he said.

Patton said MISO should consider tariff changes that would allow it to "avoid retroactively resettling markets in the future" when errors occur. He said he would be in favor of doing "the least destructive thing to the market."

"I think MISO is in an impossible position, balancing its legal obligations under the tariff with the market concerns," Patton said in summarizing the situation.

Director Nancy Lange asked about stakeholders' reactions, as the mistake resulted in some "winners and losers" among market participants. "Do you feel like there's grace and understanding, or some consternation?" she asked.

"No one is happy in a circumstance like this," Ramey said. "At the end of the day, it's an unfortunate situation we're working through."

Ramey said MISO had to strike a balance between mitigating the impacts of the mistake and protecting the integrity of its markets. He said the saving grace is that market participants self-supplied about 90% of their capacity needs and weren't affected by the prices in the voluntary capacity auction. However, he said, a few market participants relied heavily on the auction for capacity.

Ramey said MISO aims to cut down on overlooked mistakes going forward by initiating reapproval of authorizations for software and "changing the approach" to testing software.

Director Robert Lurie asked for a follow-up report on MISO's efforts to strengthen software validation.

Public Utility Commission of Texas economist Werner Roth, who is also the chair of MISO's Resource Adequacy Subcommittee, said the loss-of-load model "exists in a black box." He said little is known about the important calculations that planners in MISO count on to make resource decisions.

"We need more data transparency," Roth said. "Confidence in the LOLE model results are critical, and [MISO] could benefit from additional eyes." ■

MISO Interconnection Queue Drops to 215 GW on Tax Incentive Phaseout

By Amanda Durish Cook

DETROIT — MISO's generator interconnection queue has fallen to 215 GW as developers cut back on projects in response to the federal phaseout of renewable energy tax incentives, RTO leadership said Sept. 16 during Board Week.

The queue currently contains 1,127 projects at 215 GW. That's down from more than 300 GW earlier in 2025.

"We're starting to see significant withdrawals," MISO Vice President of System Planning Aubrey Johnson told the System Planning Committee of the Board of Directors.

Johnson said projects that entered the queue in 2023 would be hard-pressed to be online in time to meet a 2028 phaseout of federal tax incentives. He said developers are making decisions to trim projects based on the changing economics.

MISO's tariff expects that generation projects can scale the regular interconnection queue within 373 days; however, the actual average timeline is 1,511 days. The RTO is working to get to a 365-day completion rate with the help of automated studies from tech startup company Pearl Street Technologies. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

Johnson said resource changes are showing up in the next set of members' integrated resource plans. Currently, MISO's 2023 cycle is down to 102 GW from the 123 GW of projects that entered.

Aubrey Johnson (left) and Laura Rauch, MISO | © RTO Insider

"We expect to see significantly more withdrawals in the 2023 cycle," Johnson said.

Meanwhile, 75 GW are all that remains of MISO's jumbo, 171-GW 2022 cycle, and 38 GW are still standing from MISO's 77-GW 2021 cycle.

MISO said it processed 100 generator interconnection agreements totaling 17 GW from November 2024 to August 2025. Historically, only about 20% of generation proposals ever make it to interconnection agreements. The RTO expects to add 10.9 GW in nameplate capacity (6.2 GW on an accredited basis) over the rest of 2025.

Johnson said the clampdown on MISO's penalty-free withdrawals for projects in the queue could also play a supporting role in the project drop-offs.

Executive Director of Transmission Planning Laura Rauch said that although MISO members are tweaking the near-term resource plans they previously communicated, their emissions targets and renewable energy goals remain unchanged in the long term. She said there's an "acceptance that it will take longer to get to the endpoint, but no changes in those endpoints as of yet."

Finally, Johnson said the first 10 generation projects MISO selected for its first interconnection queue fast lane all seem viable, and MISO would commence official studies within days. Half of the first class admitted into MISO's interconnection queue fast lane are natural gas units and account for 4.3 of the 5.3-GW lot. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class*.)

"We showed only one constraint, and the network upgrades look like they're going to be in the couple hundred-thousand-dollar range," Johnson said of transmission needed to accommodate the new generation. He credited MISO's previous long-range transmission planning for making expedited generator interconnections possible. ■

The Bottom Line

MISO's generator interconnection queue measured in at 312 GW in late 2024. Now, the queue has slimmed to 215 GW. MISO planners attribute the depletion to the federal government scrapping tax incentives.

MISO Recounts Tough Summer; Monitor Praises Lack of Emergencies

By Amanda Durish Cook

DETROIT — MISO said the summer of 2025 was the most demanding since 2012, though the RTO steered the grid with only a single maximum generation event.

"This summer was one of the most challenging in a decade," Executive Director of System Operations Jessica Lucas told the Markets Committee of the MISO Board of Directors on Sept. 16.

Lucas said heat and humidity across the footprint were consistently high and said load exceeded 100 GW or higher for more than 750 hours over the summer, a number not seen since 2012 and nearly triple that of 2024.

The summer heat triggered more than 40 Energy Emergency Alerts across the Eastern Interconnection, but in MISO, "we only had one escalation" to an emergency, Lucas said.

MISO experienced a "sharp increase in outages" over the summer, Lucas said. The RTO reported 46 GW in average daily generation outages, compared to summer 2024's 31-GW average, culminating in a 48% increase year over year. Lucas said members reported "equipment failure" as the leading cause of outages.

"It's perhaps too early to call this a trend, but it's an important data point to monitor to see if this extends into the fall," Lucas said.

At a MISO board meeting Sept. 18, CEO John Bear said summer 2025 was "exceptionally demanding" and "signals a new normal for grid stress."

MISO Markets Committee of the Board of Directors underway Sept. 16 at the Westin Book Cadillac hotel in Detroit | © RTO Insider

The RTO encountered two rough patches in late June and again in late July. Lucas said that from June 21 to 24, the footprint contended with high demand, low wind output and high outages, leading to a maximum generation emergency on June 23. (See *MISO Declares Max Gen Emergency in Heat Wave*.)

Independent Market Monitor David Patton said he was impressed MISO avoided an emergency declaration on June 24 when virtually every other control area entered emergency procedures.

"What we saw this summer actually bears out what I've been saying: that 'MISO is the most reliable RTO' — at least among the ones that we monitor," Patton said and again criticized NERC's "high-risk" rating for the RTO.

MISO logged its almost 122-GW summer peak in late July. It also issued several capacity advisories for its South region throughout the season. (See *MISO on Track to Wrap Summer with 122-GW Peak, Addresses Frequent South Advisories*.)

The RTO kept up a near-daily cadence of capacity *advisories* for MISO South into September. The grid operator repeatedly said either forced outages, limited transfer capability or a combination of both were the culprits.

"You might have noticed we've been leveraging our capacity advisories more frequently," Lucas said.

Stakeholders can construe the repeat advisories as an "indicator" of heightened reliability risks in MISO South, she said, but the RTO wants to communicate "so it doesn't feel like anyone is caught by surprise" if it needs to institute emergency actions to deal with transmission or capacity issues.

Lucas also said MISO is developing a "set of criteria or methodology to step out of emergency declarations." She said determining when gird conditions no longer require emergency actions and terminating declarations is a complicated decision that has operating ramifications.

Amid the late July heat wave, MISO reported it unexpectedly lost a 500-kV line in MISO South on July 28-29, leading it to order a local transmission emergency and 780 MW of long-lead load-modifying resources to dial back demand.

Why This Matters

MISO said load exceeded 100 GW or higher for more than 750 hours over summer 2025 and contained the most high-load days since 2012, when MISO South didn't yet exist.

Data from Yes Energy show Entergy Arkansas' 500-kV Keo-West Memphis transmission line from Little Rock, Ark., to Memphis, Tenn., was offline July 28-29.

Lucas said MISO issued six declarations July 29 to manage the situation.

Patton said MISO's LMR use means it is learning to use demand response to manage transmission emergencies in addition to capacity emergencies. He also said MISO only incurred about $8 million in uplift charges over the summer because of sharper resource commitments and operating decisions.

"That's like nothing," Patton said. "My guess is that PJM is going to be in the hundreds of millions. …This pattern is really impressive."

Finally, MISO set an all-time solar peak of 14.1 GW on Aug. 3. The new record was double the solar output MISO achieved in summer 2024.

Patton said the larger solar fleet has brought ramping challenges that are growing with the solar fleet. He said cumulative evening net load ramp demand "has grown sharply" from about 1 GW in 2023 to nearly 6 GW in 2025 and asked MISO to continue to keep an eye on its increasing requirements. Evening ramping needs also occur later on summer nights, Patton said, with the largest need moving from 4 p.m. ET to 6 p.m. because of solar tapering down. ■

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MISO Board Set to Add Bonneville Power Exec, Keep 2 Existing Members

By Amanda Durish Cook

DETROIT — MISO is poised to retain two of its term-limited board members in 2026 while adding an executive from a federal power marketing agency.

MISO announced its slate of candidates for three available board seats: board incumbents Todd Raba and Barbara Krumsiek; and Joel Cook, Bonneville Power Administration's former chief operating officer and senior vice president of transmission services.

Cook left Bonneville in February when he took up the federal Office of Personnel Management's buyout offer.

Longtime board members Raba, Krumsiek and H.B. "Trip" Doggett are wrapping their third and final three-year terms at the end of 2025. Though they're term-limited, all expressed interest in serving a maximum fourth term that is allowable through a special waiver of MISO's rules. (See *MISO Could Replace Up to 3 Board Members by Year End*.)

Director Jeff Lemmer said MISO decided to use a waiver of normal board rules only after it weighed the need for fresh faces on the board while recognizing "the value of continuity," as MISO has "several major initiatives in flight."

Board Chair Raba thanked Doggett, the board's only departing member, for his nine-year service to the MISO board.

Illinois Commerce Commissioner Michael Carrigan, who served as one of the two stakeholders on MISO's Nominating Committee this year, said the committee had to consider that effectively, one-third of the independent board could have turned over. MISO's board is composed of nine independent directors, along with MISO CEO John Bear.

The Nominating Committee ultimately interviewed seven external candidates in addition to the existing three board members and made recommendations to MISO.

The Nominating Committee is charged with vetting and advancing potential board members, who are put to a vote of membership. The committee's members change annually, and they are composed of three MISO board members and two MISO stakeholders, one of whom typically is from a state public service commission. This year, directors Lemmer, Bob Lurie and Nancy Lange sat on the Nominating Committee alongside Carrigan and ITC's Brian Drumm.

What's Next

Chances are, the MISO Board of Directors in 2026 will include Bonneville Power Administration's former chief operating officer Joel Cook.

MISO membership will vote in late September through the end of October on the candidates. In MISO, members vote electronically on whether they support a potential board member. MISO's board elections require candidates to earn a majority of votes in support among membership. MISO members can vote for, against or abstain from selecting any of the candidates. Candidates typically earn enough favorable votes to be installed.

To establish a quorum, 25% of MISO membership (39 members this year) must vote.

MISO will announce election results sometime in November. ■

The MISO Board of Directors in session Sept. 18 at the Westin Book Cadillac hotel in Detroit. | © RTO Insider

MISO Kicks off South's Long-range Tx Plan with More Restrained Approach

By Amanda Durish Cook

DETROIT — MISO will start evaluating its South region for long-term transmission needs in 2026, beginning with Louisiana and possibly a lighter touch than used in the Midwest, the RTO announced before its Board of Directors on Sept. 16.

RTO planners *told* the board's System Planning Committee that they will approach the South with a "collaborative, investigative approach" and an eye on reliability and load growth.

MISO South has never hosted a successful, regionally cost-shared transmission project. MISO's approximately $32 billion of long-range transmission projects approved over two portfolios in 2022 and 2024 have been confined to its Midwest region.

"We strongly suspect that while MISO South long-range planning will rely on the same tariff framework, it will have different viewpoints and different requirements," Executive Director of Transmission Planning Laura Rauch told the committee.

MISO plans to start with modeling and what it calls the "South Load Pocket Risk Assessment" to inform planning. The RTO said it will use its updated, 20-year transmission planning futures in South planning once it's done reformulating them. The transmission futures are due to be completed in early 2026. (See *MISO Seeking Realistic Gen Buildout for Tx Planning Futures*.)

Rauch said MISO will focus first on Louisiana's needs "knowing that there are challenges" with load pockets and large load additions in the state. She said the RTO would develop a detailed scope of work for the South with stakeholders.

MISO said the load pocket assessment would estimate the risk of load shedding, with an initial focus on the Downstream of Gypsy load pocket in southeastern Louisiana, where load shedding occurred in late May.

Louisiana Public Service Commissioner Davante Lewis has said that the Memorial Day weekend load shed event in New Orleans demonstrates the state needs more transmission capacity in and around the Downstream of Gypsy load pocket, which predates Entergy's inclusion into MISO. (See *MISO Debates What-ifs, Vows Improvements in Front of La. PSC After Load Shed*.)

MISO South contains four major load pockets: Western, in East Texas; West of the Atchafalaya Basin, in East Texas and southwestern Louisiana; and Amite South and Downstream of Gypsy, in southeastern Louisiana.

Rauch said MISO's early modeling could uncover issues where generation solutions — not new transmission — would be more appropriate. She said the RTO is aiming for solutions that South members "could pick up on and run with."

MISO said it also plans to discontinue use of the word "tranche" to refer to the series of long-term portfolios. "Tranche 1" and "Tranche 2" referred to the first, $10.4 billion long-range portfolio and the second, $21.8 billion portfolio, respectively.

The Alliance for Affordable Energy's Yvonne Cappel-Vickery said she hoped the phaseout of the word doesn't mean that MISO South long-range planning would be "less robust" than in the Midwest.

At a Sept. 17 meeting of the Advisory Committee, Wisconsin Public Service Commissioner Marcus Hawkins asked when MISO might address its Midwest-South transfer constraint. The RTO originally said it would concentrate on the constraint in a fourth long-range transmission portfolio.

"Today, there certainly is some congestion on the North-South boundary," said Jennifer Curran, senior vice president of planning and operations. But she added that as issues evolve in MISO, adding capacity on the constraint has decreased in urgency.

"I don't think it's a near-term priority economically or for reliability. But certainly, we will keep an eye on it." ■

Why This Matters

MISO used a decidedly different tone when laying out how it would approach long-range transmission planning in its South region. Unlike the studies for its Midwest region, the RTO said an initial study into the South's load pockets might conclude that more generation, not new transmission, would be more appropriate.

Load pockets in MISO South | *MISO*

N.Y. Backs Utility Plan Including NESE Gas Pipeline

Controversial Transco Proposal Linked to OSW Stop-work Order

By John Cropley

A controversial natural gas pipeline proposal got a boost as the New York Public Service Commission approved the long-term plan for the state's largest gas delivery system.

In reviewing the proposal by National Grid's three New York gas utilities, the PSC found a reliability need for the Northeast Supply Enhancement (NESE) project proposed by The Williams Cos. and authorized National Grid to include NESE in its planning.

On its face, the move runs contrary to the state's statutory requirements to reduce greenhouse gas emissions — a significant component of which comes from combustion of natural gas in buildings and power plants.

More than 3,800 comments were submitted to the PSC in *Case 24-G-0248*, almost all of them in opposition to the National Grid plan, many of those for environmental reasons.

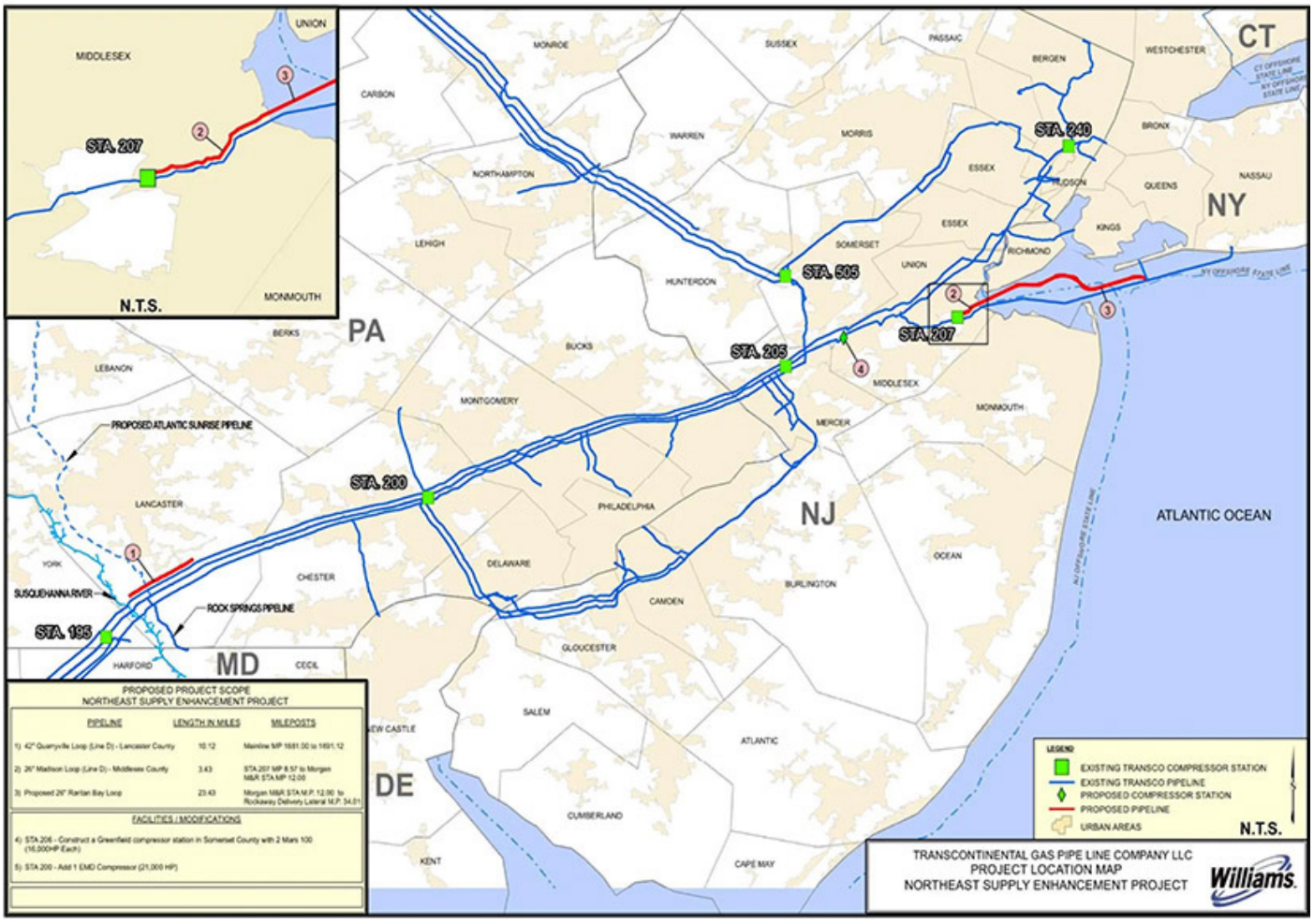
But New York's decarbonization efforts are running far behind the schedule envisioned in its landmark Climate Leadership and Community Protection Act. With the Trump administration actively opposing renewable energy development, the state may need to rely on natural gas more heavily and much longer than its leaders and policymakers had hoped.

One of the guideposts for the PSC has been the potentially disastrous nature of a natural gas outage. Restoring service requires utility technicians to visit every customer twice — with police and locksmiths in tow for locations where the customer is not present. National Grid has 2.5 million gas customers in the state, and a widespread outage could take weeks or months to resolve.

"Widespread gas outages are a real possibility today given the narrow margin between available gas supply and demand," PSC Chair Rory Christian said in a news release. "The gas planning activities we require National Grid to undertake today

Why This Matters

New investment in natural gas infrastructure raises the overall cost of New York's planned clean energy transition.



A map shows NESE, the proposed Northeast Supply Enhancement gas pipeline. | *The Williams Co.'s*

will ensure that National Grid continues to provide safe, adequate and reliable service while striving to meet the state's greenhouse gas emissions reduction targets."

Surrounded by Controversy

Transco, a Williams company, made its initial NESE pre-filing to FERC in 2016, then in 2017 formally sought to extend its existing gas network to increase supply to the New York City/Long Island region (CP17-101-007).

FERC authorized NESE in 2019. But state regulators denied key permits and Williams eventually shelved the concept.

On April 16, 2025, the Department of the Interior slapped a stop-work order on Empire Wind, an important part of New York's decarbonization strategy. The move now is seen widely as an attempt to coerce New York into approving NESE as well as the Constitution Pipeline, another pipeline extension proposal the state had stopped.

When Interior lifted the stop-work order May 19, Interior Secretary Doug Burgum implied a quid-pro-quo for NESE and Constitution. Publicly, Gov. Kathy Hochul (D) said only that the state would give full consideration to energy proposals that complied with state law.

Ten days later, Transco petitioned FERC to reissue its 2019 authorization of construction and operation of NESE. FERC granted the request Aug. 28.

The PSC's 6-1 approval Sept. 18 of National Grid's long-term gas system plan sets a path for offtake from NESE, if it is built. Other New York and New Jersey regulatory agencies are continuing their review of the proposal.

The Next Steps

Requirements in the PSC's *lengthy order* include reporting on necessary improvements to demand forecasting, non-pipe alternatives, cost mitigation and electrification.

The three utilities — The Brooklyn Union Gas Co., KeySpan Gas East Corp. and Niagara Mohawk Power Corp. — also must report on how they will optimize supply if NESE is built and how they will address reliability if it is not.

The PSC's order reflects the quandary that faces New York and Hochul. The state already has some of the most expensive electricity in the nation and must simultaneously harden, expand and decarbonize its aging energy systems. None of these were ever going to be easy or cheap, and by varying degrees they are getting harder and more expensive.

National Grid said it expects NESE to increase natural gas costs and decrease electricity costs for ratepayers, due to construction costs and lower wholesale electricity prices.

Democrats control all levels of state government, but not all Democrats are in lockstep on the energy transition and its costs. Hochul has been pushing back some of the decarbonization initiatives in an effort to keep electricity affordable, drawing criticism from some other Democrats and traditional allies.

The PSC's decision to let National Grid factor NESE into its planning was a hard truth for climate and clean power advocates who once hoped the concept was dead.

Public Power NY referred to NESE as the "Hochul-Trump pipeline" and said: "The biggest step backward for New York's climate in at least a decade is just the latest in Hochul's multiyear assault on our air and lungs."

Food & Water Watch New York said: "This foolish plan would put everyday New Yorkers on the hook to pay for a filthy, climate-killing fracked gas pipeline that isn't wanted or needed."

Leading up to the PSC vote, more than 3,700 opposing comments were submitted by individual New Yorkers and entities ranging from the Sierra Club to the City of New York to the Institute for Energy Economics and Financial Analysis to the Jewish Climate Action Network.

But there also have been voices of support for NESE.

The Plumbing Foundation City of New York called it a critical investment in the state's energy infrastructure.

IBEW Local Union 1049 pointed to the jobs that would be created by the project.

The Independent Power Producers of New York said NESE is "critically needed to maintain the reliability of the natural gas system in New York to serve Grid's downstate customers and to augment gas supply to enhance the reliability of the electric markets in the downstate region."

IPPNY also reminded the PSC of something it is very aware of: Recent federal policy changes complicate the state's efforts to replace natural gas with renewables. ■

Hudson River Towns on the Frontline of the BESS Battle

By Vincent Gabrielle

POUGHKEEPSIE, N.Y. — It was standing room only at the Town Board meeting here Sept. 3. A glance at the agenda for the night, dominated by property maintenance orders and police officer hires, would not hint at what drew so much of the public out on a Wednesday evening. But it quickly became apparent once residents began speaking.

"Lithium battery stations often go on fire," one said. "There's been many of them, and I understand that you can't use water to put them out … so they let fire smolder, just pouring toxins into the air."

The board was considering whether to adopt new zoning codes to regulate the construction of battery energy storage systems (BESS) that would overturn an 18-month moratorium. Public comment both for and against the rules went on for about three hours at the meeting, with people voicing concerns about fire safety, pollution, environmental impact and grid stability.

"I think batteries will help us be less dependent on polluting plants, like the one in Newburgh," another resident said. "My electric bills are going up; there are consistent rate hikes. I think batteries can help keep our bills low."

Town Supervisor Rebecca Edwards said that New York state recently adopted fire codes for BESS, the strictest in the U.S. Councilmember Ann Shershin said that if the town wanted solar projects, it would need BESS nearby.

Councilmember Michael Cifone said he didn't see the benefit to the town's residents and expected it to go to developers and utilities.

After more discussion, several failed amendments and one minor adjustment to construction setbacks, the seven-member board narrowly passed the zoning rules along party lines, with the four Democrats voting in favor. This makes Poughkeepsie one of the first municipalities in New York to overturn a BESS construction moratorium.

This scene is playing out in towns and cities across New York as the state pursues its goal of 6 GW of energy storage by *2030*. The Hudson Valley, New York City and Long Island are at the forefront of a massive battery rollout. Because of the state's strong home rule provisions, municipalities have significant power over whether BESS facilities get built. A bill to get BESS under state siting authority died in committee in 2025.

Why This Matters

The landscape for battery developers is chaotic and contentious at the local level in New York. Fear and confusion are fed by concerns about fire safety that are playing out town by town.

Similar debates are being held on *Staten Island* and in *Mahopac*. Westchester County passed a local law upping safety *requirements* for BESS systems after a *fire* in 2023. That same year, National Grid pulled out of a BESS and solar installation in the Adirondacks because of *community outcry*. Another battery battle is gearing up in Kingston where Terra-Gen is planning a 250-MW facility on the site of *a closed high school*. Local officials and state representatives are divided on the issue, per *Energy Storage News*.

The Poughkeepsie Town Board had been thinking about BESS zoning for roughly a year. In September 2024, the matter was suddenly brought to its attention when locals learned of a local project and descended on the board with demands and questions.

Key Capture Energy, the developer of the project, had been eyeing an industrial parcel owned by Vassar College since 2019, Phil Denara, director of development for the company, said in an interview last year. The company wanted to build a 20-MW/80-MWh battery energy storage project there because it was close to a local substation. The project fell through before the zoning ordinance could be passed.

"We're attracted to continuing to develop in New York primarily because of the policy mandates that are driving a lot of the industry," Denara said. "The Climate Leadership and Community Protection Act set an initial storage target which has been doubled by Gov. [Kathy] Hochul."

Denara said that the industry needed to "take ownership" and respond to the concerns of local residents and officials.

"We're coordinating a lot at the local level, educating local communities and ensuring that they understand that this technology is important for our decarbonization goals both in New York state and more broadly across the globe," he said.

Fire Safety

One of the most frequently voiced concerns in the debate over BESS facilities is over fire safety. In Facebook groups opposing local BESS projects, people share videos of e-bikes exploding. Others share *conspiracy* theories about Chinese military-linked companies infiltrating the U.S. battery storage supply chain.

But the recurring star of the show is the Moss Landing Fire in California, when in January a 300-MW BESS caught fire. People in nearby areas were evacuated. The cause of the fire remains under investigation, and EPA is leading an ongoing cleanup.

The environmental impacts are also unclear. While local scientists at Elkhorn Slough, a national estuary reserve near Moss Landing, found that heavy metal contamination spiked in the aftermath of the fire, they aren't certain about long-term ecological or health consequences.

"We don't know yet what is going to happen in terms of the estuary habitats here," said Ivano Aiello, a scientist at San Jose State University who studies the wetland dynamics of the area. "We are monitoring the microbes; we are monitoring the [animals, from] invertebrates all the way up to the sea otters, to understand whether those metals are moving through the food web."

The Moss Landing site was previously a gas plant. Aiello said that it was unclear whether the pollution seen from the battery fire was comparable to the effects of previous emissions.

"We use sediments as a time machine," Aiello said. "Once the emergency ends here, it's one of the things I'd like to use

the core samples as a way to assess."

Matthew Paiss, a technical adviser on energy storage safety for Sandia National Laboratories and former firefighter, lives near Moss Landing. He said that in general, consumer-grade rechargeable lithium batteries were not manufactured to the same high standards as utility-scale batteries.

"People are looking for the cheapest battery they can, and if your job is as a gig employee and you're delivering Uber Eats, and your $500 battery loses capacity, you're going to take it to a local shop and get a couple cells changed out," Paiss said. This kind of tweaking, coupled with hard physical wear and tear, was the cause of most failures, he said.

Paiss has studied the general causes of BESS failures using BESS Failure Database data from the Energy Policy Research Institute. In general, he said that utility-scale battery fires occur because of installation errors and failures with overall protection systems. The Moss Landing facility kept many of their batteries in old buildings on site, which may have contributed to the fire by reducing "fire segmentation," he said.

"Best practices moving forward are to limit the amount of propagation," he said. "That's why we're seeing a lot of outdoor containers."

Lakshmi Srinivasan, the team lead for EPRI's energy storage program, said that since 2011, the rate of BESS fires has *declined* worldwide as the industry improves safety. Of the failures they've been able to isolate causes for, the battery cells themselves were not the most likely to cause fires. Other components, installation problems, bad thermal management and HVAC systems were the most common causes.

"The key takeaway from this work was actually that we know how to engineer controls and the balance of the system to prevent these kinds of failures going forward," she said.

Local Government Outreach

What seemed to have the most impact on the Poughkeepsie Town Board's decision to implement zoning was a panel discussion in June in which the Dutchess County Mayors and Supervisors Association met with experts to discuss BESS facilities.

The meeting, held at the Board of Cooperative Educational Services Conference Center, attracted policy wonks, local government officials, firefighters, first responders and concerned citizens. The crowd listened to presentations by Paul Rogers, a former New York City Fire Department lieutenant working for the Energy Safety Resource Group; Jeffrey Seidman, a Vassar College professor; and Jennifer Manierre, director of clean energy siting for the New York State Energy Research and Development Agency.

Seidman helped organize the meeting with town Supervisor Edwards. What had originally been an "old boys club" for local government officials became, for one night, a policy discussion forum.

Seidman explained the benefits of utility-scale batteries, primarily load shifting, enhanced grid reliability and reduced use of expensive peaker plants. Batteries would help reduce energy costs if built in sufficient numbers across the state, he argued.

"Demand for electricity is going up absolutely everywhere," Seidman said. This meant more demand for substations and transmission lines. "Batteries save us money by not making us have to do those expensive upgrades."

Manierre offered NYSERDA's service to help local officials with zoning and planning and explained the role of batteries in the state energy plan.

Rogers reviewed the New York Fire Code development process, the safety considerations afforded to firefighters and the relative risks of fires at battery plants compared to more conventional buildings. Each facility needs to have an on-call person to handle emergencies and coordinate with first responders, he explained.

"We put these things in place to try to help … because our thing is to keep everyone safe," Rogers said. "I'll never say 'never,' but we significantly reduce the risk of an event taking place,"

Battery storage facilities were required by the fire code to undergo large-scale fire testing, he explained. This meant that manufacturers needed to test-burn entire battery cabinets.

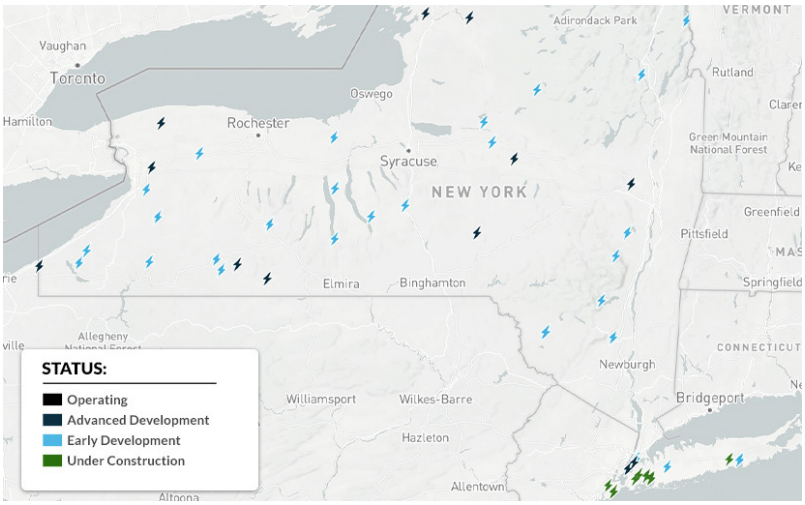
"What the [testing] proves and validates is that if something takes place that it doesn't leave the container, it stays in the container," Rogers said.

Seidman told *RTO Insider* that local organizers were setting up another forum in Ulster County, where several battery facilities are planned. He hopes that by mid-November, a similarly productive conversation can happen there too.

"I think a lot of people are not ideologically or otherwise opposed to batteries, but they just don't mean anything to them," Seidman said. "Like, 'why should we put our necks out?'"

Seidman said that he received a good response from town officials after the meeting and that one had invited him to a local temple to give a talk on batteries. He hopes that his efforts can make a difference for the climate and local air quality.

"I'd love to make this a traveling road show," he said. "This is something I would like to repeat." ■



A map generated with Yes Energy data showing battery energy storage systems in various stages of construction. | *Yes Energy*

NYISO Monitor Report Highlights Generator Outages During Heat Wave

By Vincent Gabrielle

As NYISO continues its Capacity Market Structure Review, the Market Monitoring Unit used its second-quarter State of the Market *report* to highlight potential issues with how the ISO forecasts resource availability, with the late June heat wave as a test case.

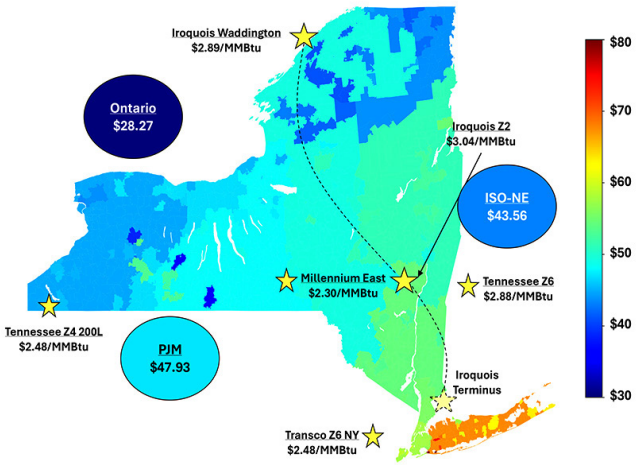
Load for the quarter peaked around 31.9 GW on June 24, right in the middle of the three-day heat wave that led NYISO to issue an energy emergency. (See *NYISO BIC Dissects Power Prices During June Heat Wave*.)

All-in prices were up across all zones of the New York Control Area, driven by an increase in natural gas prices. But "in addition to the gas prices, I think the extraordinarily high load level that peaked in late June … certainly added a lot to real-time prices," Pallas LeeVanSchaick, vice president of Potomac Economics, told the Installed Capacity Working Group on Sept. 8.

LeeVanSchaick offered a breakdown of the performance of fossil fuel generators, emergency capacity and large curtailable loads during the heat wave. He said the MMU wanted to highlight these resources because they have not been the focus of prior capacity accreditation discussions.

"It's sort of outside the standard analyses that we do," he said. "It has to do with capacity accreditation. … Obviously we and … NYISO and other regional market operators have spent a lot of time on how to improve capacity accreditation."

The analysis compared the performance of fossil fuel resources systemwide during the June heat wave against their weighted average equivalent demand forced outage rate (EFORd), which measures how much capacity a resource could reliably provide when in demand. During peak hours in the heat wave, the MMU found that units were out of service more than predicted by their average EFORd.



NYISO system price diagram for Q2 2025 | *Potomac Economics*

"The concern here is if you look at the stuff that was unavailable due to either forced outages or performance, the number comes out to 24.9% on the 24th, compared to an average EFORd of 5.9%," LeeVanSchaick said. This means that EFORd is being calculated too low because it is not taking into account how certain generators are being used, he said.

Some fossil fuel plants, like peakers, are dispatched to run at high outputs very rarely. These plants are aging, which reduces their ability to operate at high output. If they aren't called on to push high power out frequently, EFORd will not capture when they fail to function at those levels, leading to far more optimistic rates. This problem also occurred with steam turbine units during the heat wave.

"This heat wave presented a unique opportunity because we haven't seen conditions where so many units were asked to operate at high levels," he said.

In addition, some capacity that was available to the ISO was not recognized by its real-time model as available. About 213 MW that previously participated in the Capacity Limited Resource and Emergency Capacity programs were not scheduled and did not produce energy; 73 MW of capacity that were not scheduled but produced voluntarily were also not recognized.

"What we found was that there was not an operating procedure to utilize these megawatts that was ready to be used on these days," LeeVanSchaick said. "Although the conditions and operating reserve shortages would have warranted using this capacity, it wasn't actually scheduled."

Roughly 90% of large loads across 600 MW of demand response programs voluntarily curtailed during the peak load hour June 24, he said. These were resources participating in the Special Case Resource (SCR), Demand-Side Ancillary Service (DSASP), distributed energy resource and Behind-the-Meter Net Generation programs.

These DR actions had some inefficiencies. Over 200 MW of SCRs were curtailed when they could have provided DSASP reserves; 70 MW of SCRs curtailed for four hours as requested but then increased consumption during the peak, meaning they weren't deployed when they were most valuable.

"We're going to need to think further about how to potentially refine these programs so that these things are consistent for resources to be participating efficiently," LeeVanSchaick said. ■

Why This Matters

The Market Monitoring Unit highlighted a potential problem with how NYISO uses EFORd to predict the likelihood of resource availability.

PJM Revises Non-capacity Backed Load Proposal

By Devin Leith-Yessian

PJM has revised elements of its *proposal* to create a non-capacity backed load (NCBL) product for large loads as the Critical Issue Fast Path (CIFP) embarks on determining how to address the reliability challenges posed by accelerating data center load growth. (See *PJM Board Initiates CIFP Addressing RA, Large Loads*.)

The proposal would create a new form of interconnection service in which customers would not receive, or pay, for capacity in a set delivery year, and the amount of load procured in the corresponding capacity auctions would diminish accordingly. It would be triggered in delivery years where forecasted supply for a Base Residual Auction (BRA) is less than the reliability requirement. In nearly 200 pages of *comments* submitted to PJM in response to its initial proposal, many stakeholders argued it would undermine investment signals for new generation and lead data center developers to look to other regions. They also said PJM proposed a solution without taking the time to fully understand the scope of the issue.

The core change PJM made to the proposal is how large load customers might receive a mandatory NCBL designation. Under the version of the proposal PJM presented at a CIFP meeting Sept. 15, the RTO would calculate the amount of NCBL that would be needed across its footprint and allocate a share of that to electric distribution companies and load-serving entities based on the amount of planned, unbuilt large loads expected to come into service in their service area during a delivery year in which a shortfall has been identified. It would then fall to each EDC and LSE to determine how to assign their NCBL allotment to customers.

When first *presented*, the proposal had a voluntary pathway for customers to request NCBL status when PJM determined there might be a capacity shortfall in an auction, followed by the RTO making mandatory NCBL assignments if the deficiency persisted. Much of the criticism in the subsequent comments argued that PJM lacks jurisdiction to assert how retail customers receive service.

Tim Horger, PJM | © *RTO Insider*

Why This Matters

PJM received more than 200 comments on its revised proposal, including from the governors of Pennsylvania, Maryland, New Jersey and Illinois.

PJM's approach to determining how much NCBL would be distributed to each zone would exclude existing load and planned large loads that intend to participate in demand response or bring-your-own-generation (BYOG) programs. Because the final NCBL designation would be left to retail service providers, however, Senior Director of Market Operations Tim Horger said it is possible that EDCs and LSEs, with direction from state regulators, could opt to include large loads already in operation or planning to enroll in DR or BYOG.

Horger told *RTO Insider* in an email that if a planned large load's DR or BYOG participation does not cover its expected load, the remainder would be added to the NCBL area calculation.

Data center representatives said the proposal appears to force customers to take flexible or inferior service unless they enroll in BYOG or DR, and even then there would be no certainty that they could entirely mitigate the risk of being required to take NCBL service. That uncertainty around who is subject to the proposal would impact the prospect of making investments in PJM for those in need of large amounts of energy, they said.

Horger said concern that large loads could face unreliable service would be present even if PJM does nothing because of the heightened risk of manual load shedding being needed. The proposal would at least provide customers with savings on capacity and possibly more advance notice on when they would need to curtail in real time. He characterized NCBL as changing the prioritization of the load-shedding procedures.

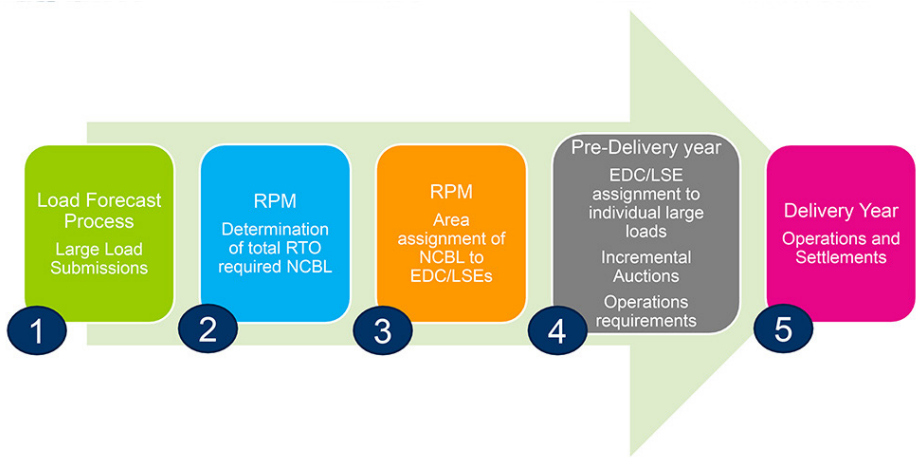
Denise Foster Cronin, vice president of federal and RTO regulatory affairs for the East Kentucky Power Cooperative, said the proposal could result in scenarios where retail service providers bilaterally contract capacity for expected large customers, only for that load to be subject to NCBL and pulled out of the capacity market, while the self-supplied generation would remain on the supply side of the ledger. She argued that would effectively offer that paid-for capacity to other customers participating in BRAs.

"Additionally, despite having secured capacity to meet the totality of the load obligation, PJM would require its assessed amount of NCBL to be curtailed prior to emergencies. Since we are one of the transmission owners that PJM will require to execute the NCBL curtailment, that presents us with a Hobson's choice, as none of our load should be curtailed," Cronin told *RTO Insider*.

Responding to stakeholder inquiries on whether the NCBL proposal is being envisioned as a permanent addition to PJM's capacity market or a temporary measure, Horger said it's viewed as a way to bridge a gap across a reliability shortfall expected to last a few years. While a firm retirement for the product has not been included, he said the RTO is open to including a trigger to eliminate the process, such as after the reliability requirement has been cleared for a certain number of years.

PJM Associate General Counsel Mark Stanisz said the CIFP discussion demonstrates that the proposal impacts wholesale rates and supports the position that it falls under federal jurisdiction. He said PJM states have chosen to rely on the RTO's markets and the courts have routinely determined that FERC and the Federal Power Act have jurisdiction over the rates, practices and mechanics behind RTO capacity constructs. He added that the federal energy policy ecosystem is rapidly evolving, with several executive orders since the start of 2025 and an artificial intelligence action plan in place.

In a statement responding to the proposal, the Natural Resources Defense Council recommended an approach requiring all new large loads to procure their own generation to avoid disruptions to the capacity market from individual customers. It argued that the proposal would leave data center load in the capacity market,



PJM presented its non-capacity backed load proposal, which would create a new product for curtailable load that would be exempted from capacity payments. | *PJM*

causing customers to pay significantly higher costs and push data centers to install inefficient backup generation to cover periods where they are curtailed.

"PJM is creating rules for how to manage the reliability risk, essentially by proposing to shut off new data centers during any hour of the year when there is insufficient electricity. While this approach would preserve reliability in a draconian way, it will do little to protect residents from rising bills and require highly polluting backup generators to run many more hours each year," the NRDC wrote.

Additional Package Details

PJM presented additional information on how it envisions the proposal being implemented, including specifying that NCBL curtailments would fall before pre-emergency load management deployments in the stack of emergency procedures.

Customers assigned NCBL status would be exempt from capacity payments by removing their load from the corresponding zone's forecast peak load when determining how much capacity must be procured in each zone. The relevant EDC or LSE would be responsible for reducing its obligation peak load to reflect the reduced capacity requirement. PJM would shift the resource requirement and variable resource requirement curve, which determines the amount of capacity procured in a BRA, to reflect the RTO-wide NCBL designation.

The definition of a large load would be set at 50 MW, with a case-by-case review for including smaller customers.

PJM staff acknowledged many areas of the proposal require further refining, including what would happen if a customer or retail service provider failed to curtail NCBL.

PJM Broaches Alternative Proposals

PJM presented additional concepts that could develop into alternative CIFP proposals, including an alternate NCBL with only voluntary participation.

Eliminating the mandatory designation would grant states and retail service providers more ability to balance reliability risk against costs on their own, the RTO said. If participation is low, that could mean higher risk of manual load shedding, however.

Ongoing discussions around expanding provisional interconnection service could also be shifted from the Planning Committee to the CIFP. The changes being considered aim to identify resources that could enter partial operations before their full transmission network upgrades have been complete, making more energy available to dispatchers during emergency conditions. (See *PJM Stakeholders Endorse Expansion of Provisional Interconnection Service*.)

Another concept would require planned large loads to bid into capacity auctions for the year in which they intend to enter service, with a cost commitment that would hold even if they do not come online. Doing so would improve the certainty of the load forecast. Bids would be submitted either through the customer's retail service provider, or the customer could become its own LSE, though PJM said both present jurisdictional quanda-

ries. The proposal could be paired with a voluntary NCBL model, though the risk of manual load shed could still be high if many customers do not opt to participate.

The changes could be limited to how shed load is allocated, or they could be paired with other proposals, though PJM cautioned that if no other market design changes are made, the auction could repeatedly clear short of the reliability requirement, triggering the Reliability Pricing Model backstop auction.

An expedited interconnection option could create a parallel queue for a select number of resources with strict eligibility requirements, including being operational within three years. PJM's Jason Shoemaker said it could deliver interconnection agreements in 10 months with minimal impacts to the overall queue. Because implementation would fall after the completion of Transition Cycles 1 and 2, he said there would be no disruption to projects already in the queue.

PJM could also develop more transparency for planned generation and large loads and assist in identifying opportunities to create partnerships between the two.

RA Scenarios Highlight Capacity Shortfall in 2030

PJM Senior Manager of Policy Initiatives Susan McGill *presented* five scenarios looking at how different levels of supply growth could impact a capacity deficiency PJM has projected in 2030. Each built off the 2025 Load Forecast, which estimated that net energy load growth will increase by about 4.8% annually over the following decade.

The first scenario assumed new resources would come on at the historically slow rate, bringing 6.6 GW of unforced capacity online, while policy-driven deactivations would take 8.1 GW of supply offline. Paired with 22.9 GW of load growth, that would result in a 24.1-GW UCAP deficiency.

The direst scenario assumed a 25% faster rate in resources interconnecting, offset by 29.2 GW of load growth from requests to co-locate load with new resources, resulting in a 24.7-GW shortfall.

Removing the co-located load requests and holding generation deactivations flat would result in a 10.4-GW shortfall, while adding the highest DR participation seen in the last five years to the equation would add 3.3 GW of supply and shrink the gap to 7.1 GW.

The final scenario assumed additional load flexibility would participate, resulting in the market clearing with no surplus.

Wide-ranging Comments Submitted on CIFP

Dozens of organizations and individuals submitted comments to PJM, many of which debated the merits of the NCBL proposal or urged the RTO to extend its focus to load forecasting, DR and the interconnection queue.

The governors of Pennsylvania, New Jersey, Maryland and Illinois jointly wrote that a CIFP process is needed to address rising load growth and correspondingly high capacity prices while stating that the impact of the NCBL proposal is difficult to model and could carry unintended consequences. If it were to be implemented, they recommended limiting it to the 2028/29 and following auction.

"An explicitly temporary and more broadly applicable NCBL methodology that is mandatory for only the next two BRA performance periods … could provide a partial and short-term solution. However, we feel strongly that this temporary solution must be accompanied by additional measures that address more fundamental issues and will not risk artificially perpetuating extremely high capacity prices through a potentially flawed trigger mechanism," they wrote.

They said the CIFP scope should explore overhauling load forecasting, creating incentives for large loads to bring their own generation, using regional transmission planning to create new interconnection opportunities and speeding the interconnection of energy-only resources.

Exelon said the original iteration of PJM's proposal would infringe on state jurisdiction and create a compliance trap for utilities stuck between the RTO imposing civil penalties if they fail to curtail NCBL customers and state regulators that might object to that curtailment.

"The proposal establishes a new category of retail service for certain large loads whereby those customers would receive service on an interruptible basis subject to curtailment in emergencies and would be exempted from paying capacity charges. This is not simply a tweak to PJM's wholesale market rules; it is the creation of a novel form of retail electric service, with specified terms and conditions set on a regionwide basis by PJM," the utility wrote.

Rather than rushing to a solution without understanding the problem, Exelon said that PJM should more thoroughly study the resource adequacy threats and hold education on the load shed risk in the Mid-Atlantic.

"Ultimately, we owe it to our customers, current and future, and our state policymakers and regulators to begin informing them of the real and increasing possibility of load shedding in the not-to-distant future, even as we continue efforts to build both the transmission and generation needed to address and mitigate that risk," Exelon said. "Doing so may also result in additional creative solutions that would further mitigate and address this risk. Without being informed of the imminent need, we may lack the collective alignment amongst policymakers, regulators and operators to more aggressively tackle these issues."

Advanced Energy United argued that PJM should focus its efforts on a BYOG pathway, which it said is likely the only way for significant amounts of supply to interconnect in time to make an impact, and address the load forecast to avoid mismatching transmission and generation development against load growth.

United argued the proposal would suppress capacity prices and hold back new investment in a manner that would make it hard to backtrack from.

The Digital Power Network said data centers lend themselves to load flexibility, which is underutilized because of outdated programming and inaccurate modeling of load-shedding events. Rules around when data centers could be curtailed must be clear and transparent, but PJM's proposal would leave them in the dark, it argued.

"Flexible digital loads should be incentivized to participate in resource adequacy initiatives rather than be excluded from them. A framework that encourages voluntary participation through programs such as demand response while rewarding flexibility would strengthen adequacy and preserve reliability," it wrote. ■

Governors Call for More State Authority in PJM

States Seeking Greater Role in Governance, Decision-making

By Devin Leith-Yessian

PHILADELPHIA — Virginia Gov. Glenn Youngkin requested that PJM reopen the nomination process for two open seats on its Board of Managers to consider two candidates recommended by the states.

Addressing a technical conference on the state of PJM, Youngkin said there needs to be real reform immediately at PJM, with granting states a greater voice in decision-making atop the list. Much of the full-day conference focused on the prospect of governance reforms and how the RTO can meet the challenge of rising data center load.

The request comes after Youngkin and Pennsylvania Gov. Josh Shapiro co-signed a letter to the Board of Managers urging the RTO to consider nominating former FERC Commissioners Mark Christie (R) and Allison Clements (D) to serve as board members and for a larger discussion to be launched on setting aside two seats for candidates nominated by member states.

The PJM Nominating Committee instead opted to nominate Robert Ethier, a former ISO-NE executive, and Le Xie, faculty co-director of the Power and AI Initiative at the Harvard School of Engineering and Applied Sciences. The Members Committee is set to vote on appointing Xie and Ethier during its Sept. 25 meeting, which is the voting deadline FERC granted in response to PJM's request for a delay. (See *Robert Ethier, Le Xie Nominated for PJM Board*.)

In response, seven state governors signed onto a *letter* expressing disappointment that Christie and Clements were not nominated, saying that would have signaled that PJM is listening to the states. They wrote that the lack of board representation for consumers and state regulators is a core concern for the governors.

"Our recommendation was intended to provide a constructive solution that would have both strengthened PJM's governance and signaled that voices representing the public interest are afforded a meaningful place in decision-making at PJM," the governors wrote. "The Nominating Committee's decision to disregard our recommendation indicates that our concerns for our consumers are not being taken seriously and underscores how the states' role in PJM is being minimized."

PA Governor Josh Shapiro speaks at a multi-state technical conference focused on governance and resource adequacy in PJM. | © RTO Insider

Why This Matters

Governors in the PJM area are pressuring the RTO to make immediate governance changes that give more power to the states — with the implicit threat that they could pull their states out absent quick action.

"PJM cannot expect to continue making decisions that affect the daily lives of our citizens and the economic future of each of the states while hiding behind stale process and refusing to grant the opportunities for meaningful input that exist in other RTOs," they continued. "This is a fundamental and existential challenge: PJM must find ways to provide sufficient representation for the millions of consumers we represent."

The governors added that they do not mean to discredit the qualifications of Ethier and Xie but believe they do not have the backgrounds needed to address the crisis state leaders see. They advised the board "to embrace a new, more meaningfully collaborative, vision for PJM's relationship with the states as a whole and to take steps to ensure greater ratepayer representation as the RTO makes major decisions in the coming months."

"Please recognize the urgency of this moment — the need is not simply for indisputably talented individuals like Dr. Ethier and Dr. Xie, but for leaders who understand the uniqueness of PJM's member states, our citizens and our shared responsibility for the reliability and affordability of electricity," they said. "There is a pressing need to restore trust in PJM's governance and legitimacy."

'Move More Quickly'

Speaking at the conference, Youngkin said PJM has failed to forecast rising load in its footprint in time to get ahead of it,

introducing interconnection bottlenecks and causing a resource adequacy crisis.

"And that is why we are working on legislation that will allow Virginia to reassess whether our utilities will continue to be part of PJM. Virginia will need to decide what is best for Virginia ratepayers. This doesn't mean that we are walking away, but it does mean that collectively we recognize we need to represent and protect our ratepayers. And that means sending a clear, unifying signal that PJM must modernize, must reform. PJM must improve its planning and, above all, PJM must work to restore confidence that recently has been so badly lost."

Opening the technical conference, Shapiro said PJM is at an inflection point where the states have empowered it with increasing authority to not only coordinate power flows but also ensure resource adequacy. Now it has responded too slowly to reform its interconnection process to facilitate the generation growth needed to meet rising demand.

He said the situation has been made more difficult by the Trump administration creating barriers and cutting funding for new generation. PJM was founded in Philadelphia nearly a century ago, and there is now an opportunity to reform its governance to provide more opportunity to work with its member states.

In a press conference following his address, Shapiro said PJM should revise its leadership structure to provide more authority over decision-making to the states. And while he prefers to take a cooperative approach, he is prepared to seek legislation requiring utilities to leave PJM absent changes.

He said PJM will need to become more sensitive to the needs of the states and consumers, including giving a voice to those entrusted to lead the states, as well as cultivating a more direct connection between state utility commissions and PJM leadership than currently exists. For those changes to be effective, he said PJM has months, not years.

"We need PJM to move more quickly … if PJM cannot do that, Pennsylvania will look to go it alone," he said.

Maryland Gov. Wes Moore said the unified voice of 13 governors underscores the crisis at PJM, with families facing double-digit rate increases driven by the mismanagement of the regional grid. Grid oversight lacks transparency and responsiveness, which creates a need for states to have more of a hand in governance, he said.

Following the conference, 11 states signed onto a joint statement of intent outlining plans to create a PJM Governors' Collaborative to "promote greater state and consumer representation in the governance and decision-making processes of PJM."

The group would not hold regulatory or enforcement power, but would coordinate communications among PJM, state regulators and elected officials, FERC, the Organization of PJM States Inc (OPSI) and Consumer Advocates of the PJM States (CAPS). It could also provide technical support on topics before PJM, identify issues for the states to address, and "develop and advance joint positions and strategies related to PJM issues." Only West Virginia and Kentucky did not sign onto the statement. ■

Monroe's Western Outreach Pays Dividends for SPP

RTO's Former COO Has Long Met with Western Utilities

By Tom Kleckner

PORTLAND, Ore. — When former SPP COO Carl Monroe hands out his business card these days, it reads, "Carl Monroe, Principal, Munro Advisors."

"Munro?" Is that a misspelling?

"It's the traditional way of spelling Monroe. They were Irish," Monroe says of his ancestors. "'Munro' means they're from the River Roe in Northern Ireland."

The Munros were also "tenacious fighters" during the 1400s and into the 1600s, centuries punctuated by the Hundred Years' War, King Henry VIII's reign, the English Civil War and the beginning of the Jacobite Risings.

"They fought so ferociously that the Scots hired them as mercenaries to fight all the Scottish clans," Monroe says. "Eventually, they got enough esteem that they are one of the clans that are considered [part of] Scotland, or Scotch-Irish."

The Munros were so highly respected that the Scots gifted them land for their own castle, Monroe says.

When the story is related to an SPP stakeholder, who had just greeted Monroe on the sidelines of an industry conference, he says, "Had I known that he was so lethal, I would have given him a wider berth."

Of course, unlike his ancestors, Monroe is anything but "lethal."

Carl Monroe (right) listens to attorney Bill Booth, a partner at Michael Best & Friedrich, during an industry conference. | © RTO Insider

Why This Matters

Former SPP COO Carl Monroe's fascination with the electricity industry has led to decades of outreach to the Western Interconnection and the race to build markets in the West.

A veteran of more than 45 years in the industry that first included stints with Ameren and Entergy, Monroe spent 15 of his final 22 years with SPP as its COO. That made him responsible for grid operations across the RTO's 14-state balancing authority area, a footprint that grew from eight states during his tenure with the addition of Nebraska's public power entities and the Integrated System in the Dakotas.

Independent transmission developer Grid United, for whom Monroe now serves as one of three members of its Advisory Board, credits him for being "instrumental" in expanding SPP's footprint by 20% and adding $1.5 billion of transactions in the real-time energy market.

"Carl has helped to shepherd us through tremendous change and growth. We just wouldn't be where we are today without his leadership," SPP CEO Nick Brown said when Monroe announced his retirement in 2019. (See *SPP COO Monroe to Retire in Early 2020*.)

The footprint is expanding once again. The *RTO's expansion* into the Western Interconnection will be live in April 2026. In 2027, *SPP Markets+*, a day-ahead service offering that includes real-time commitment and dispatch, will begin operations. It will replace the grid operator's *Western Energy Imbalance Service* market, which it has administered on a contract basis since 2021.

SPP has also been serving as a *reliability coordinator* for primarily future Markets+ participants since 2019, and it was chosen by CAISO and five utilities nearly 10 years ago to administer the *Western Inter-*

connection Unscheduled Flow Mitigation Plan, which manages the use of certain controllable devices to mitigate congestion along transmission lines. The RTO was also selected as the program operator for the Western Power Pool's six-year-old *Western Resource Adequacy Program* (WRAP).

Much of that is credited toward the "instrumental" Monroe and his outreach for more than a decade to Western Interconnection entities. He led SPP's effort to add the Mountain West Transmission Group, a *Front Range* initiative that fell apart after Xcel Energy subsidiary Public Service Company of Colorado pulled out and led to a broader Western Market Exploratory Group that studied the benefits of a regional market. Years later, PSCo is one of seven entities joining Markets+ after Colorado regulators ordered the state's utilities to join regional markets.

Jack Moore, an SPP IT engineer involved in the Markets+ development effort, spoke recently during a stakeholder meeting here. He prefaced his comments by remembering his first visit to Portland in 2010, when he accompanied Monroe to talk with the Bonneville Power Administration about "an energy market in the West."

"So, 15 years later, here we are," Moore said.

"That was one of the things Carl was always doing, just seeing whether there was a way that SPP could meet potential stakeholder needs," said Jim Gonzalez, SPP's director of seams and Western services. "As we hear opportunities for help, facilitating and collaborating, that's one of the things SPP has always really been open to. If we have neighbors and there seem to be needs, can we help meet those needs?"

"That's a lot of it," Monroe says by way of agreement. He described a "paradigm shift" that has taken place with wholesale markets and the West's growing understanding of their benefits.

"That's why you're seeing a lot of the development of markets out there. I think you're starting to see that paradigm shift about having a real real-time [market] and a wholesale market that actually provides more benefits to them than trying to hold onto control of those things," he says.

"It really gives them a way to mitigate some of the risks. … That's why you see a whole lot of interest, but there's some underpinnings that at least we stumbled through in the East," Monroe adds, listing tariffs, balancing authorities, resource adequacy and "those types of things" that grid operators do. "It just means that a group of utilities can decide how to do those things together in a way that provides a benefit to the whole that is greater than the benefit each of them can provide individually."

As an example, he points to the WRAP and utilities that got together "with SPP's help" to understand how they could work together in a resource adequacy program.

"I was an adviser for some of that too," he says. "Together, they could rely on each other's resource adequacy more and ensuring that each party was upholding their portion that they had to rely on."

"In nearly 15 years as a director at SPP, I've met no one with greater knowledge of markets and operations or with such ability to collaboratively address complex issues," SPP Board of Directors Chair Larry Altenbaumer said of Monroe when he announced his retirement.

His decision just happened to coincide with the COVID-19 pandemic, making him something of a forgotten figure. He was asked what he intended to do with his spare time and whether he would go into consulting.

"I didn't know the difference between retirement or COVID. Everybody just went home to work," he says. "I spent some time with SPP near the end working with the West trying to help them out, first of all, just to understand what it means to work together and what benefits you get out of it, [and] beyond that, what SPP could do for them. Of course, you're seeing some of that play out today."

SPP gave him a contract to "do one little thing," but when he was finished with the project, he was free to work with others. With his somewhat eponymous consulting firm, Monroe helps clients with bulk power system operations, reliability standards, wholesale energy markets, strategic planning, FERC tariffs and other issues.

"I don't want to do things that are not interesting to me, but this industry is really interesting," he says. "The transition that it's going through … it's just been fascinating to watch the industry and what the industry needs to do, but at the same time, how it's needed within the country and what reliability means to the country itself as critical infrastructure. …

"There are things I know that I can help people with," Monroe adds. "There were a few people that called and wanted some help and just understand SPP and our wholesale markets and stuff like that. So that's been a lot of fun."

Besides his work with Grid United and its HVDC projects, Monroe has also consulted with solar and hybrid storage in both interconnections.

"Some are looking at markets, and some are looking at coordinating their activities together with others for optimized operations," he says. "But the most interesting thing, [which] gets me my 49th state to do work in, is an RTO for Alaska."

Monroe graduated from Auburn University with a degree in electrical engineering. While at SPP, he decorated his office with a black-and-white photo from his time on The Plains. The image shows *Elvis Presley's 1974 performance* on campus at the Memorial Coliseum. Monroe would direct visitors to the AV booth in the background, from where he was responsible for lighting The King.

He joined SPP from Entergy, originally being hired to manage the RTO's growing IT department. He was elected as an officer and promoted to executive vice president and COO in 2004, where he oversaw operations, the power system's long-term forecasting and planning, and interregional coordination.

"I believe his personal efforts, contributions and leadership were critical to the tremendous development and success of the Southwest Power Pool," said longtime member Mike Wise, with Golden Spread Electric Cooperative.

"I'll do what I can to help people," Monroe says. "If I can't help you, I'll tell you I can't help you. That's fine. I'm enjoying what I do, whether I do anything or not."

Nothing to do? Given Monroe's history, that's a little hard to believe. ■

FERC Requires Additional Z2 Filing from SPP

Commission Accepts RTO's Order 2222 Implementation Timeline

By Tom Kleckner

FERC has directed SPP to submit a compliance filing for its proposal to unwind credit payment obligations assessed under Attachment Z2 of its tariff for transmission service taken from 2008 to 2016.

In an order issued Sept. 18 at its monthly open meeting, the commission determined that SPP lacked specifics in its proposed five-year plan to process about $138.5 million in refunded transmission service revenue credits paid during the refund period (March 2008 through August 2015) and an additional $8.2 million to refund point-to-point rates that increased during that time (*ER16-1341*).

FERC directed the RTO to explain how the refunds from entities that elect the payment plan will be allocated to entities owed refunds and to lay out how the plan interacts with a separate short-payments plan. It ordered the grid operator to clarify the allocation of "necessary revenue reduction in proportion to the outstanding net amounts owed by each entity on an aggregate basis after netting together the individual amounts payable and receivable for that invoice date."

"We acknowledge that an option for a five-year payment plan could provide needed flexibility to the parties that must make repayments, but details of the specifics of the payment plan, and what the impact on refunds of this plan will be, remain open questions," the commission wrote. "Accordingly, we direct SPP to explain how it would proceed both for entities that owe and are owed refunds in a situation where an entity selected the five-year payment plan option but was unable to pay refund amounts during the five-year period."

SPP's response is due within 45 days of the order.

The *Z2 issue* has dogged SPP since 2016, when the grid operator owed $147 million plus interest to transmission customers for the historical period. Staff said in October 2024 that interest at that time stood at $33.4 million. (See "Grid Oper-

Why This Matters

SPP has been trying to resolve issues with transmission upgrade credits market participants have been paid since 2008. The RTO has told FERC that refunds and resettlements total more than $650 million as of June 2024, and that this amount grows by between $3 million and $4 million monthly.

Shutterstock

ator Waiting for FERC Order to Resettle Z2 Funds," *SPP Markets & Operations Policy Committee Briefs: Oct. 15-16, 2024*.)

Under the attachment, transmission upgrade sponsors receive credits from any upgrade users whose service could not be provided "but for" the upgrade. The attachment also requires the RTO to invoice the charges monthly and to make any adjustments within one year.

However, software problems delayed the attachment's final implementation for eight years before 2016, during which the RTO did not invoice for the upgrade charges. FERC approved a waiver request to settle more than 365 days in arrears, but in 2019, the commission reversed course and said SPP should have settled Z2 from only September 2015 forward. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

In January 2022, the grid operator updated its proposed refund plan and made an informational update to the commission in September 2024. If approved, SPP plans to send out refund invoices with interest for the refund period, accrued to the current invoice date.

Once a new settlement system is deployed in the coming months, invoices would be issued for the September 2015-January 2020 operating days. Additional resettlements from February 2020 would be run monthly in the current settlement system, along with normal current day Z2 settlements, until SPP catches up to the operating month.

SPP told FERC that the refunds and resettlement, before interest on refunds, total at least $657.8 million (as of June 2024). That amount grows by between $3 million and $4 million each month, it said.

The RTO has said it expects to resettle everything in about four years.

2nd Order 2222 Compliance Filing

Also at the open meeting, the commission accepted SPP's second Order 2222 compliance filing, subject to another compliance filing to be submitted within 60 days (*ER22-1697*).

FERC found that in SPP's December 2024 filing, the RTO complied with the first compliance order's directives related to the commission's decision to decline its jurisdiction over the interconnections of distributed energy resources to distribution facilities for the purpose of aggregation. The commission also found that SPP met Order 2222's requirements of allowing distributed energy resource aggregators to register aggregations under one or more participation models to accommodate their physical and operational characteristics and proposing a maximum capacity requirement.

The commission rejected protests by Advanced Energy United, Sierra Club and virtual power plant operator Voltus that SPP's proposed 2030 implementation timeline is "analogous" to MISO's. (See *FERC Permits 2030 Finish Date for MISO Order 2222 Compliance*.)

The commission said it rejected MISO's first timeline because the RTO proposed to defer Order 2222 implementation for several years. It said SPP's proposal to implement the order in the second quarter of 2030 complies with the requirement for a "reasonable implementation date with adequate support to show that the proposal is appropriately tailored for its region and implements Order No. 2222 in a timely manner."

"Here, SPP is not proposing to defer Order No. 2222 implementation. Rather, SPP has adequately explained why an effective date five years from the commission's acceptance of its revised proposal is appropriate for its region due to its implementation needs," FERC wrote.

Approved in September 2020, *Order 2222* directed all FERC-jurisdictional regional grid operators to revise their tariffs to allow DERs to participate in their capacity, energy and ancillary service markets. (See *FERC Opens RTO Markets to DER Aggregation*.) ■

SPP Names Director to Lead Markets+ Monitoring

SPP has named Tim Vigil, chief member relations and strategy officer for the Pacific Northwest Generating Cooperative (PNGC), as director of the Market Monitoring Unit's office dedicated to Markets+.

In the role, Vigil will lead the development of market monitoring reports and metrics for Markets+, manage processes for identifying and addressing market design flaws, monitor market operations functions and support a future surveillance team responsible for screening market participant behavior.

The new position within the MMU was created in advance of the RTO's launch of its Western day-ahead and real-time market in 2027, SPP said in a *press release*.

Carrie Bivens, SPP's vice president of market monitoring, said Vigil's broad industry knowledge, strong market insight and long experience in the Western Interconnection "will be invaluable to our monitoring preparation efforts for the new market and future oversight responsibilities."

SPP has named Tim Vigil as director of the Market Monitoring Unit's Markets+ office. | *SPP*

SPP said Vigil was instrumental in forming and implementing SPP's Western Energy Imbalance Service market. He chaired the stakeholder-led Western Markets Executive Committee from 2020-2021.

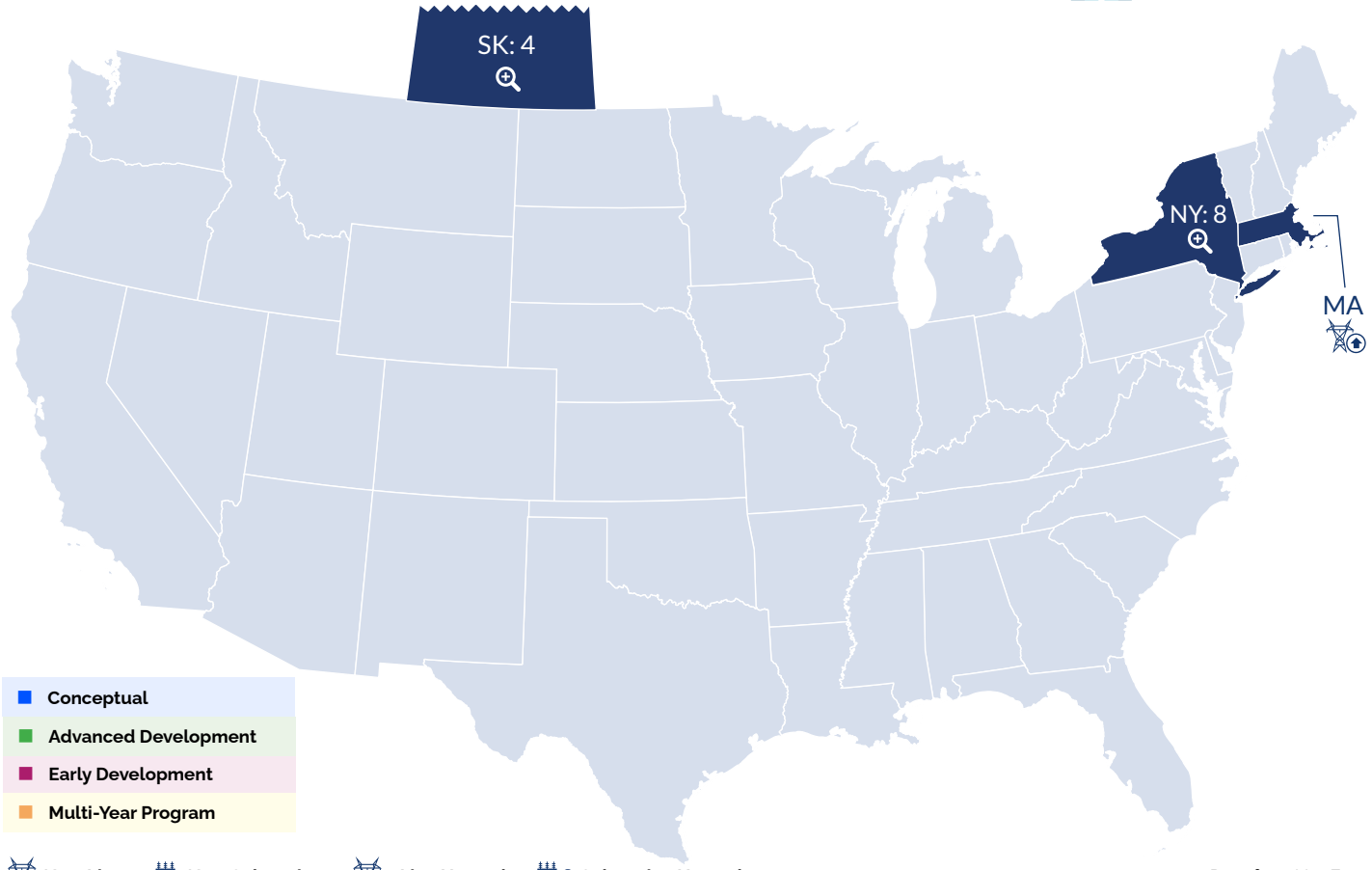
Vigil joins the SPP MMU from PNGC. He previously served as director of development-origination at NextEra Energy, COO at Delta-Montrose Electric Association and in various roles at the Western Area Power Administration. He holds a bachelor's degree in economics from California State University Northridge.

The MMU is independent of the RTO and its contract services, including Markets+. It functions independently to avoid actual or apparent conflicts in its oversight role. ■

— Tom Kleckner

T&D Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

	Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
	Brighton - Electric Avenue Underground Cable Modernization Program	Eversource Energy	NSTAR Electric	115	2029	MA / MA
	Klinekill - Falls Park New Line	Avangrid	NYSE&G	115	2031	NY / NY
	Station 23 - Station 42 Line 920 Rebuild	Avangrid	Rochester Gas and Electric	115	2029	NY / NY
	Station 46 - Station 95 (Circuit 261) Line Upgrade	Avangrid	Rochester Gas and Electric	4	2028	NY / NY
	Cold Springs Substation Upgrade	Avangrid	NYSE&G	115	2031	NY / NY
	Pierce Substation Upgrades	Avangrid	NYSE&G	69	2031	NY
	Morris 46 kV Substation Upgrades	Avangrid	NYSE&G	46	2034	NY
	RG&E T&S Asset Condition Replacement Program 2027 - 2031	Avangrid	Rochester Gas and Electric	69	2031	NY
	RG&E Wood Pole Inspect and Treat (WPIT) Replacement Program 2031 - 2035	Avangrid	Rochester Gas and Electric	27	2035	NY
	Water Security Agency's (WSA) East - Coteau Creek - WSA West Line Project	SaskPower	SaskPower	138	2027	SK / SK
	Taylor Bay Reinforcement Project	SaskPower	SaskPower	230	2029	SK
	Tableland - Saskatchewan/North Dakota Border New Line	SaskPower	SaskPower	230	2027	SK / SK
	Iyuhana Solar Network Upgrade (Estevan Area)	SaskPower	SaskPower	230	2028	SK / SK

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

Company Briefs

Hyundai Battery Plant Faces Startup Delay Following Raid

A battery plant co-owned by Hyundai is facing a minimum start-up delay of two to three months following an immigration raid, Hyundai CEO Jose Munoz said.

The Georgia plant, which is operated through a joint venture between Hyundai and LG Energy Solution, was at the center of the largest single-site enforcement operation in the Department of Homeland Security's history earlier in September. About 475 workers, mostly South Korean nationals, were arrested, according to U.S. immigration officials.

The plant, part of a $7.6 billion factory complex to make battery-powered models, was slated to come online later this year.

More: *CNN*

Rivian Breaks Ground on $5B Plant

Rivian broke ground on its $5 billion EV manufacturing facility in Georgia on Sept. 16.

The company had announced a pause in the facility's construction back in March to speed production of its R2 midsize SUV and save money.

The company hopes the facility will be able to make 200,000 vehicles yearly starting in 2028.

More: *The Associated Press*

Microsoft to Spend $4B to Build 2nd Wisconsin Data Center

Microsoft last week said it plans to spend $4 billion to build a second data center in Mount Pleasant, Wis.

The new project includes construction of the facility and technology infrastructure and will house part of what the company calls a distributed training supercomputer.

Construction is planned to be finished by the end of 2028.

More: *Milwaukee Journal Sentinel*

Federal Briefs

EPA to Defend 'Forever Chemical' Cleanup Rule

The EPA last week said it will defend a Biden era-rule that is expected to keep polluters on the hook to clean up toxic "forever chemicals."

The rule in question designated two types of these chemicals as "hazardous substances," giving the EPA more authority to clean up their contamination and require polluters to pay for it. In a court filing, lawyers for the Justice Department said the EPA "has reviewed the underlying rule and has decided to keep the rule in place."

In a statement, EPA Administrator Lee Zeldin said the Trump administration was seeking a balance between holding polluters accountable and not punishing the wrong companies.

More: *The Hill*

Clean Energy Jobs Grew 2.8% in 2024

Clean energy jobs grew 2.8% in 2024, adding nearly 100,000 new jobs and outpacing the rest of U.S. employment (0.8%), according to E2.

The growth of clean energy jobs also outpaced job growth across the rest of the energy industry, as the number of Americans working in occupations related to clean energy now exceeds the number of jobs in oil, gas and coal by more than three to one.

More: *E2*

IG Finds Holes in Interior Reviews of Renewables on Public Lands

The Bureau of Land Management consistently failed to comply with federal regulations when reviewing applications for wind and solar projects on public lands, according to an audit by the Interior Department's Office of Inspector General published last week.

The audit found the BLM did not assess most applicants' technical and financial ability to develop renewable energy projects, maintained incomplete files and failed to screen applications in a timely manner.

The Interior watchdog blamed a lack of internal controls and training for the weaknesses and said they put the agency at risk of awarding permits to unqualified entities and prevented it from collecting rents and fees.

More: *Reuters*

Mid-Atlantic news from our other channels

N.J. Solar Project Developers Scramble, Wonder What Comes Next

NetZero Insider

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

State Briefs

CONNECTICUT

Gov. Lamont Seeks Delay on Vote over Tx Line

Gov. **Ned Lamont** last week suggested that United Illuminating may soon agree to postpone a final decision on the utility's plan to erect a new transmission line through sections of Fairfield and Bridgeport.

The project, known as the Fairfield to Congress Railroad Transmission Line, has sparked opposition from residents, businesses and elected officials who have objected to both the location and the utility's plans.

The Siting Council had scheduled a final vote on the project on Sept. 18 after its members previously indicated their support in a non-binding straw poll. However, the vote could be delayed if Lamont and United Illuminating agree to hold further talks with state and local officials to come up with an alternative plan that would alleviate concerns.

More: *CT Mirror*

MAINE

PUC Approves 5 New Clean Energy Projects

The Public Utilities Commission last week approved five renewable energy projects aimed at supporting the state's clean energy goals.

The projects include a 4-MW hydroelectric facility and four solar facilities totaling 257 MW.

More: *News Center Maine*

MASSACHUSETTS

CleanChoice Energy Faces $5M Fine for Misconduct

The Department of Public Utilities last week moved to fine CleanChoice Energy $5 million, citing "egregious misconduct and a pattern of misconduct" that includes misleading marketing. DPU Commissioner Cecile Fraser also said the department will look to revoke the company's license to do business in the state.

Fraser said there is evidence to support allegations that CleanChoice sent a number of direct mail ads that compared the CleanChoice cost to an outdated basic service rate that was higher than the actual rate the customer was paying at the time of the mailer, gave eight customers "inaccurate and deceptive" information in contracts or contract summaries, and made three "deceptive" sales enrollment calls, among other allegations.

CleanChoice has until mid-October to formally respond to the DPU notice.

More: *WWLP*

NEVADA

PUC Approves Greenlink Construction Costs

NVEnergy

The Public Utilities Commission last week approved a billing switch for NV Energy, as well as the construction costs for the utility's Greenlink transmission line.

Starting in April, power bills for all of NV Energy's Southern Nevada customers will be based on the maximum amount of electricity used at a single point during a day — no longer following the traditional billing practice of charging based on total electricity consumed. It will be the first time an investor-owned utility in the U.S. will apply this kind of mandatory billing structure to all residential customers.

Commissioners also agreed to let NV Energy charge its customers for a sizable portion of the under-construction $4.2 billion transmission project known as Greenlink. Southern Nevada utility customers will cover 70% of the cost, while Northern Nevada customers will fund 30%, according to the order. Estimates show that Southern Nevada residential customers will see a resulting price increase of between $4.35 and $4.42/month.

More: *The Nevada Independent*

NEW YORK

Madison County Wind Farm Demolished After 20 Years

Seven wind turbines, part of the state's first commercial wind farm, were demolished last week in Madison County.

The turbines, which had stood for more than 20 years, were brought down in a controlled demolition that took about 20 seconds.

Once the debris is cleared, the land will be restored to its original agricultural use.

More: *CNY Central*

TEXAS

Solar Sets New ERCOT Records

Solar set a new ERCOT record on Sept. 9, generating almost half of total demand while providing more than 40% of the state's electricity for seven straight hours, from 9 a.m. to 4 p.m.

The 29,877 MW was the 17th new record of 2025 and 7,785 MW higher than the first record of 22,092 MW set Jan. 24.

Battery storage has also set four discharge records in September. The latest occurred on Sept. 11, sending 7,741 MW (10.6%) of total demand back into the grid in the early evening.

More: *IEEFA*

VERMONT

Justice Asks Judge to Rule Against State's Superfund Law

The Justice Department last week asked a judge to rule in its favor in an ongoing lawsuit over Vermont's law that requires polluters to pay for their carbon emissions, called the Climate Superfund Act.

The act is a first-of-its-kind legislation that asks oil and gas corporations to pay for their greenhouse gas emissions between 1995 and 2024. The Justice Department's lawsuit called the climate action "unconstitutional."

More: *VT Digger*

VIRGINIA

Franklin County Votes Down Solar Farm Proposal

The Franklin County Board of Supervisors last week voted 5-1 to reject a proposal for a new solar farm following significant community pushback at a public hearing.

Robin Ridge Solar proposed a 35-MW solar facility on 121 acres.

More: *The Roanoke Times*