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YES ENERGY

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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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S&P Global's Nodal Trader Conference

FERC Veterans Share Worries over Agency's Independence

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FERC's future is at risk as the Supreme Court appears poised to overturn an FDR-era precedent that would allow President Trump to fire commissioners of independent agencies without cause.

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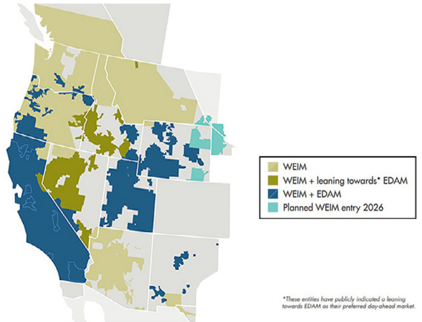
Patton Calls on ERCOT to Operate its System Less Conservatively *(p.10)*

CAISO/WEST



CAISO

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ERCOT

ERCOT

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ERCOT is tracking over 200 GW in large-load interconnection requests, but only about 6.5 GW have been energized or approved for energization. At the same time, it says there is no moratorium on energizing large loads, but that they must clear certain requirements first.

Texas Gov. Abbott Appoints 4th Commissioner to PUC *(p.30)*

FERC/FEDERAL

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Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections (p.12)

The secretary of energy asked FERC to assert jurisdiction over large loads, which could help data centers and others with speed-to-market concerns, but would upend the current practice where states oversee customers' connections to the grid.

Trump Appoints Swett to Chair of FERC *(p.14)*

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Beam Me Up, Scotty

By Steve Huntoon


Steve Huntoon

There was a big event the other day *rolling out* the U.S. Army's new Janus Program, "a next-generation nuclear power program that will deliver resilient, secure and assured energy to support national defense installations and critical missions."

The Army *will contract* for 18 nuclear "microreactors" (two each at nine Army bases). "The reactors will help keep weapons powered and maintain critical base operations when other energy sources go down because of bad weather, cyberattacks or other grid disruptions."

This is wasteful, counterproductive and dangerous. It is worse than the Department of Defense microgrid initiative that I *critiqued* eight years ago.

Like the microgrid initiative, the Janus Program ignores the fact that the vast bulk (87%) of Army base power outages are from problems on the base's distribution system. Existing building-specific diesel backup generators provide backup for distribution system outages. Nuclear microreactors (like microgrids) would not provide backup for distribution system outages. Thus, microreactors would cause base buildings to lose backup for 87% of outages, eliminating the vast bulk of existing backup capability.


The delivery date for the Project Pele microreactor has been extended from 2024 to 2028. | *BWXT Advanced Technologies*

Moreover, Army bases don't need complex microreactors to add to their infrastructure burdens. Instead, our bases need expansion of sensible and incredibly cheap resilience exercises, like those provided by MIT's *Lincoln Laboratory*.

With specific focus on cyberattack disruptions, microreactors and the rest of the base's electric system would be connected to communication networks. Building-specific diesel backup generators are not. So microreactors would create new vulnerability to cyberattacks.

And these microreactors would pose a huge threat to our troops. It appears they would not have containment structures, which means that an attack could spread highly radioactive nuclear fuel across a base and *surrounding areas*. If captured, the fuel could furnish the nuclear material for *a dirty bomb* or even fissile material for a crude *nuclear bomb*. No such risks exist with diesel or other fossil fuel generators.

This vulnerability exposes the irrationality of microreactors. If they are sited overseas because of attack threats to fossil fuel supplies, then those same attack threats would exist for the microreactors, with much worse potential consequences. If they are sited on or close to U.S. soil, then there are no threats to fossil fuel supplies that microreactors would relieve.

This intractable dilemma would appear to explain changing DOD messages about siting: first far-flung *bases*, then dropping that *approach*, and then resurrecting it during the Janus Program *rollout*.

Oh, on the minor matter of cost: Diesel backup generators cost *about* $600,000/MW. The Army says the Janus Program would build on DOD's Project Pele, which involves a 1.5-MW microreactor contracted for in 2022 at an estimated cost of $300 million, *amounting to* $200 million/MW. That is 33,300% more than the cost of diesel backup generators. It's even 1,200% more than the cost of *the new Vogtle units* in Georgia.

And did I mention that in 2022, the delivery date for the Project Pele microreactor was *said to be* 2024? The delivery date now is *said to be* 2028. Two years until delivery has tripled to become six years until delivery, which should surprise no one familiar with the nuclear industry.

Why This Matters

Army bases don't need complex microreactors to add to their infrastructure burdens. Instead, our bases need expansion of sensible and incredibly cheap resilience exercises, says Steve Huntoon.

Speaking of money, where are the untold billions for the Army microreactors going to come from? The Janus Program rollout mentions the Defense Innovation Unit (DIU), which has an *annual budget* of about $1 billion. The planned microreactors would cost many times that, hurting existing DIU initiatives and spending money that Congress has not authorized or appropriated (not to put too fine a point on it).

In normal times we might look to the Pentagon press corps to ask about some of this, but the Trump administration *has revoked* almost all Pentagon press passes. And we know how congressional oversight is going *these days*.

To the Moon, Alice!

Not to be outdone by DOD, NASA plans to send a 100-kW *microreactor* to the moon, at an estimated *cost* of $6.2 billion. This works out to $62 billion/MW. What this microreactor would do on the moon is not entirely clear, other than somehow compete with China and/or Russia in somehow *laying claim* to something. Maybe it could charge Elon Musk's cellphone when he shows up?

Speaking of Musk, where is DOGE when we need it? ■

— Columnist Steve Huntoon, a former president of the Energy Bar Association, practiced energy law for more than 30 years.

It's Time to Take Distributed Generation Seriously

By Dej Knuckey

Dej Knuckey

When solar and the grid are mentioned in the same breath, acres of shining panels come to mind. But it's time for rooftop solar to become a part of that vision, not the peripheral realm of hippies and preppers. Two milestones were reached that reinforce why the U.S. needs to take rooftop solar seriously and how it can be an essential part of our energy mix.

On Oct. 18, California clocked its 200th day of 2025 where wind, solar and hydro supplied 100% of the main grid's needs for part of the day, a milestone noted in a LinkedIn post by Stanford University professor of civil and environmental engineering *Mark Jacobson*. That means that more than two-thirds of the days in 2025 have had times where renewable energy production was so high that its output was curtailed or, one hopes, stored in batteries for later use.

Yet as impressive as that was, it excluded the significant contribution of rooftop solar.

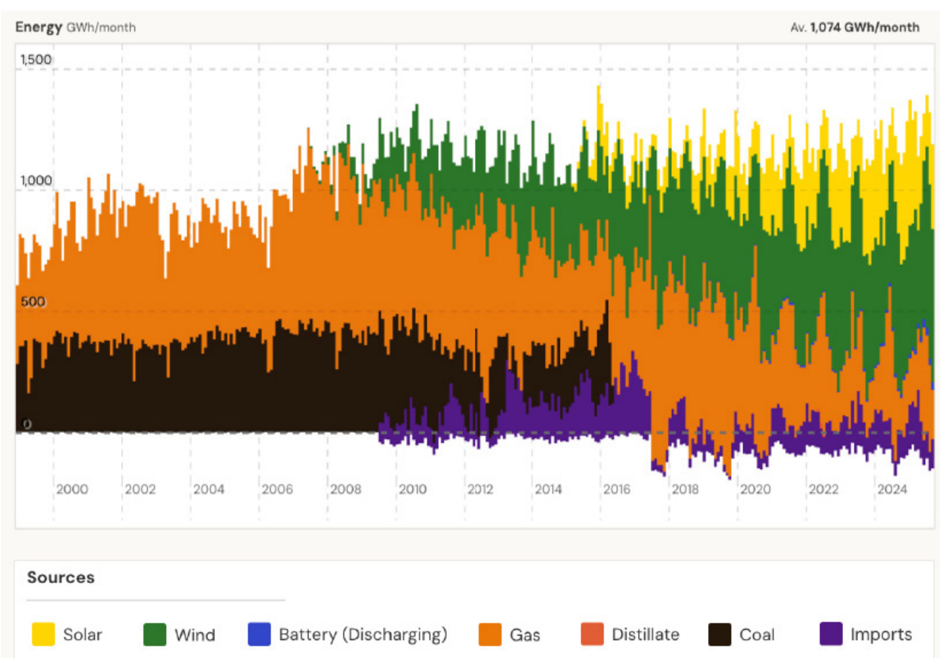
The Role of the Rooftop

As California hit its 200th day with 100% of demand met by renewables for a slice of the day, a different milestone was being reached Down Under.

South Australia achieved greater than 100% of its "operational demand exclusively from rooftop photovoltaics" for the 13th time since September 2023. *John Noonan*, a consultant who watches Australia's electricity markets closely, responded to the post celebrating California's milestone. His comment led me down a rabbit hole, exploring the energy system of my homeland, how it's become the world's leader in rooftop solar and what that means for the grid.

When you talk to many grid operators in the U.S., rooftop solar is perceived like homemade goodies at a bake sale: cute, but hardly a threat to Big Cake. It's only in states like Hawaii, Massachusetts and California where the sum of the rooftop systems is considered significant that it's seen as an integral part of the energy system.

In California, *utility-scale solar supplied about 19%* of the state's total electricity net generation in 2024, and when small-scale systems (less than 1 MW) are included, that increases to 32%. The majority of small-scale systems are residential rooftop systems.



In 18 years, South Australia went from wind and solar providing 0% of its electricity to 73%. | *Open Electricity*

Why This Matters

If permitting and interconnection become cheap, fast and easy, the cost of residential solar should fall enough to offset some of the loss of the federal tax credits, and perhaps even the tariffs on imported system components, says Dej Knuckey.

To See the Future, Look South

To see what the grid could look like when rooftop solar is not just common but plentiful, we need to look south, as far south as South Australia, the country's fifth-most populous state.

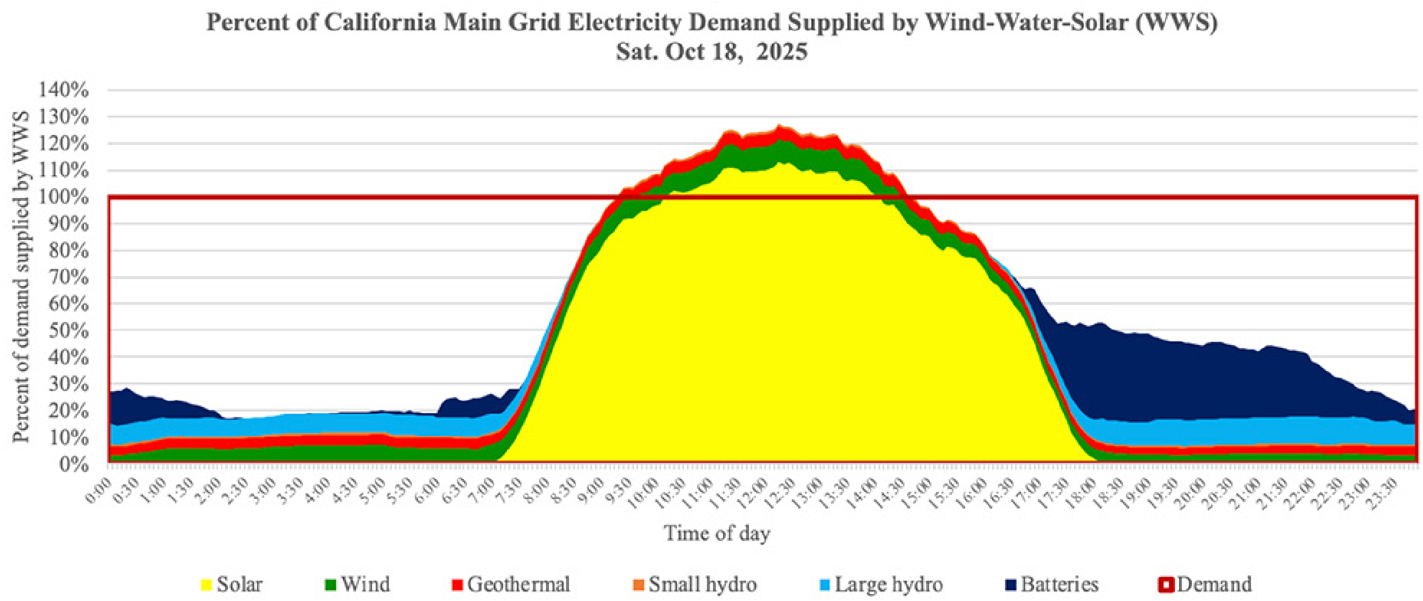
Of course, Australia and the U.S. are wildly different: Australia is about the same size as the contiguous lower 48 states, with a population smaller than Texas', and South Australia is about 1.5 times the size of Texas with a population like Idaho's. But the two countries have similar housing stock, with around two-thirds of households in single-family homes and two-thirds of those homes owner-occupied.

Where they differ massively is in solar penetration: South Australia *leads the world in residential solar installation density*, with 54% of homes having rooftop solar.

In Australia's other state with more than 50% penetration, Queensland, residential and business rooftop solar broke records recently, *contributing more than 5 GW (over 52%) of state demand* on a day that set new springtime temperature records.

Can There be Too Much Rooftop Solar?

In late 2022, South Australia had a chance to answer that question. A *storm toppled a 275-kV transmission tower*, severing the state from the national electricity market. Suddenly, rooftop solar provided more than enough power to the then-isolated state grid, and the grid operator remotely turned off 400 MW of rooftop solar to ensure grid stability. Why? According to the



On Oct. 18, California reached its 200th day of wind, hydro and solar meeting 100% of demand for part of the day. | *CAISO*

Institute for Energy Research, "if rooftop solar can meet all or most of local demand, there is little or no firm capacity available for the system operator to use if another major incident affects the grid."

This is where deployment of batteries, both behind-the-meter and utility-scale, comes into play. Rooftop solar is a grid asset when grid operators can use batteries to *play the crucial role of firm capacity*. Referring to blackouts in Spain and Portugal earlier in 2025, RMI said: "If U.S. grid planners wish to learn from the Iberian Peninsula's story, there is one resource that has proven it can compete to provide grid stability and affordability at the same time: batteries.

"Batteries can support all three main components of grid reliability: resource adequacy — the long-term ability to meet demand on peak; stability (also known as operational reliability) — critical short-term services like frequency and voltage regulation that stabilize the grid; and resilience — the ability of the grid to quickly recover from or support critical systems during an outage."

On Track to 100% Renewables

In Australia, rooftop solar is not simply a nice bonus that supplements utility-scale electric generation during peak demand; it is an essential slice of the power supply as the country moves to 100% renewables. And, not surprisingly, utility-scale electric generation no longer is dependent on fossil fuels, though they are far from fully phased out.

Utility-scale solar and wind have been significant in Australia for some time, and the country is ramping up deployment of utility-scale energy storage to enable it. In August, *renewables provided more than 47% of all grid power for a time*, setting a record.

There still are some highly polluting fossil fuel power plants on the grid. For example, brown coal — a wetter, and therefore less efficient, type of coal also called lignite — still powers half of my home state of Victoria's grid, with the country's largest brown coal mine supplying two power plants that feed 3.4 GW of baseload into the grid.

But despite the current dependence on fossil fuels, most states are setting bold goals to phase them out. In July 2024, South Australia *signed a Renewable Energy Transformation Agreement* with Australia's federal government, setting a goal to meet 100% of its electricity needs with wind and solar by 2027. Since then, *all but two of the country's states and territories* have signed on.

Rooftop's Role in National Goals

A transformation of the scale of Australia's is hard to imagine without the strength of its rooftop solar market.

In any country with a strong rooftop solar market, its growth didn't happen in a vacuum: policies such as feed-in tariffs, net metering and tax credits supported the industry. That's why the not-particularly-sunny Germany took the early lead in the global market. In Australia, where sunshine is plentiful, generous feed-in-tariffs encouraged many homeowners to adopt rooftop solar, though a *widespread desire to stick it to the utilities* tipped the scale.

Today, 38.7% of the 10.9 million Australian homes have solar, and 5% of those also have batteries. Compare that to the *U.S., where just 7% of homes have solar*, a number not likely to double until 2030, and even that's in question given recent political headwinds.

Globally, rooftop solar will continue to grow. The *DNV Energy Transition Outlook 2025* said plunging costs of solar and battery hardware mean that behind-the-meter solutions "will represent 30% of all solar and 13% of all power generated by 2060."

Even in markets with high solar penetration, growth will continue as batteries are added to solar systems, both new systems and those undergoing retrofit. Those batteries provide the critical energy storage that enables solar generated at the height of the day to be consumed during early evening peak consumption.

Toward Baseload Rooftop PV

Energy storage is essential if rooftop solar's large share of generation is to be considered as baseload power, *Noonan said*: "The frequency of these 100% operational demand reports from South Australia is going to become routine as South Australia begins to define the concept of 'baseload rooftop PV' when paired with large behind-the-meter industrial-scale, commercial-scale, residential-scale and battery electric vehicle-scale grid-forming static inertia battery energy storage systems."

Energy storage is important to the economics of the rooftop solar industry. The DNV outlook said installing standalone solar has become less profitable in regions with higher rooftop solar penetration and time-of-use tariffs, such as Australia, Germany and Spain. "Focus is shifting instead to solar+storage systems, where prosumers store excess energy and use it during peak-price periods to maximize savings. This is also supported by growing adoption of dynamic feed-in rates, declining lithium-ion battery costs, and evolving grid tariffs, taxes and levies."

The same trend is being seen in the U.S. In California, for example, *batteries are paired* with more than half of new residential solar systems.

Solar's Momentum Needs Steady Policy, Low Prices

In the U.S., state rooftop solar markets start and stop like an old car needing a tune-up. Residential solar in the U.S. has a reputational problem — arguably because of the industry's sales and financing methods — with 40% of homeowners believing it is hard to find a trustworthy installer. And with multiyear payback periods and the lingering stain from some sales practices, selling solar is a struggle in many markets.

In 2025, the U.S. rooftop solar market's struggles have grown: *state-level battles* over feed-in-tariffs and net energy metering policies are a constant challenge, and now federal tax credits face *early termination* at the end of the year.

Rising concern about the reliability of the grid in the U.S. is countering these headwinds. Grid reliability — a problem perceived by more than half of homeowners — is becoming one of residential solar's strongest selling points. Before the recent federal policy changes disrupted the economics, *76% of homeowners saw solar as a good investment*, according to *an Aurora Solar survey*: surprisingly high given how few of them have actually invested in a home solar system.

Yet the biggest issue slowing rooftop solar in the U.S. is price: The industry sees no end to the burdensome soft costs — especially permitting hurdles that vary by town — that drive prices up to three or more times those of comparable systems in Australia. The resulting high installed-system prices make payback periods two to three times longer than in Australia, and the loss of the federal tax credits will tack on another year.

While we struggle to restart the market after each policy bump in the U.S., in Australia, its momentum is unstoppable. Why? Because it's so damn cheap.

Australia's rooftop solar is dramatically cheaper than in the U.S., so much so that Saul Griffith, MacArthur Genius and author of "Electrify," *said Australian rooftop solar* is "the cheapest retail energy ever provided to a consumer in human history. It is extraordinary."

Beyond Federal Policy: What We Can Do in the Meantime

For as long as I've followed the U.S. residential solar market, there has been talk of cutting the soft costs so American rooftop solar is competitively priced by global standards. Industry and government efforts have failed so far.

I've heard solar installers rail against my neighboring city, where permits cost thousands of dollars, take weeks and require five copies of paperwork, much of which is gratuitous. Two cities over, the same system gets a permit in 15 minutes at a reasonable cost, with simple electrical line drawings.

The *Department of Energy's admirable SolarAPP+ program* was supposed to do what the industry failed to do: streamline permitting across the thousands of local permitting jurisdictions so that adding solar to a home has no more red tape than, say, electrifying appliances or adding home EV charging.

If America's distributed energy system is to flourish, the states need to get together and do what the federal government no longer cares about. It's a strategy that *blue-state governors are using to address health care costs*. They could easily do the same for rooftop solar by rolling out the existing SolarAPP+ program across every town and city in their states. Similarly, if state regulators pushed for rapid interconnection of home solar systems, going solar would be less frustrating for installers and homeowners.

If permitting and interconnection become cheap, fast and easy, the cost of residential solar should fall enough to offset some of the loss of the federal tax credits, and perhaps even the tariffs on imported system components. And if all of that leads to simpler sales and fewer buyers bailing mid-process, costs will become even more competitive.

Rooftop solar — and the grid that benefits from it — deserves the same coordinated approach many states are giving health care. Doing so will protect thousands of jobs, offer American homeowners a way to get reliable and affordable energy, and improve grid reliability. ■

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

FERC Veterans Share Worries over Agency's Independence

By Rich Heidorn Jr.

WASHINGTON — Two FERC veterans shared their worries over the commission's future as an independent agency as it awaits a crucial Supreme Court ruling.

In a panel discussion at S&P Global's *Nodal Trader Conference* Oct. 24, former FERC Chair Richard Glick and former FERC economist Devin Hartman cited expectations that the Supreme Court will overturn an FDR-era precedent — allowing President Donald Trump to fire commissioners of independent agencies such as FERC without cause. (See *Will the Supreme Court End FERC's Independence?*)

"That has a whole series of ramifications that are not, in my opinion, positive," said Glick, a Democrat, who was denied reappointment in 2022 after crossing former Sen. Joe Manchin (D-W.Va.) on natural gas policy. (See *Glick Bids Farewell to FERC*.) "I mean, the reason that we have agencies like FERC is because they perform quasi-judicial functions. … It's not going to be a positive result when the president tells whatever commissioner, 'You're going to vote this way on this particular rate case, or you're not going to be here any longer.'"

Hartman, director of energy and environmental policy at the *center-right* R Street Institute, questioned how FERC would operate if it were subjected to Office of Information and Regulatory Affairs *(OIRA) review* at the Office of Management and Budget.

"So how does this work now? Do the five commissioners sit there and negotiate something and then check in with the White House? Does the chair check in with the White House?" asked Hartman, who worked at FERC between 2012 and 2016.

"OMB isn't staffed to understand what independent agencies do. We've talked with OIRA before. They don't even know … what taxonomy to apply to cost-of-service regulation. Is this a regulatory action or deregulatory action compliant with the president's agenda? We don't even know what box to check on this. That's literally where we're at right now."

The two FERC veterans, and fellow panelist Erin Eckenrod, vice president of environmental products for AES, also discussed permitting reform, Trump's war on offshore wind and difficulties expanding grid-enhancing technologies.

Speaking at S&P Global's Nodal Trader Conference were (from left) former FERC Chair Richard Glick; Erin Eckenrod, AES; and Devin Hartman, R Street Institute. | © *RTO Insider*

Why This Matters

FERC's future is at risk as the Supreme Court appears poised to overturn an FDR-era precedent that would allow President Trump to fire commissioners of independent agencies without cause.

'Permitting Permanence'

Hartman said Trump has introduced a new type of risk into the electric industry by rescinding the Bureau of Ocean Energy Management's approval of offshore wind projects: the loss of "permit permanence."

"There is so much more artificial risk of executive actions [now]. … This is a huge problem. … When [the Trump administration does] this, it legitimizes and sets precedent for future administrations to do the same thing for resources they don't like. You have some of the more liberal members of the Senate [thinking], 'What goes around comes around here.' And notably, look at how the oil and gas industry — who ostensibly this administration wants to help — *responded* to some of the punitive actions on renewables. One of the leading LNG developers — I won't say who — told me right after the offshore wind decision: 'We have to make decisions over the next seven to eight presidential cycles. We cannot have this much artificial risk."

"The risk premiums are going up for a variety of infrastructure projects," Hartman added. "At the very least, I think that could creep into some of the congressional conversations [on permitting legislation: the concept of] permitting permanence."

AES' Eckenrod agreed. "The risk premium that is now being built in, I will argue, it's offsetting any benefits you're getting from reduced interest rates. It's counterproductive."

'New Environment' for Permitting Legislation?

Eckenrod questioned whether the Trump administration might seek to undo the Clean Air Act (CAA) if it threatens the siting of natural gas-fired generators.

Hartman said the CAA could be at risk because the courts' willingness to let Trump stretch the limits of executive authority has changed the outlook for potential congressional action on permitting legislation. (See *Bipartisan Transmission Permitting Reform Bill Introduced in House*.)

"The White House is feeling very optimistic, frankly, about where they can go with just executive authority alone in this new … environment," he said. "If you're going to see a permitting package pass, the Republicans are going to want to see deeper permitting reform than what they sought last year, because they think that the status quo has shifted favorably. So, things like, yes, the Clean Air Act might be on the table now. Should ambient air quality standards have a cost-benefit test? … I think there's going to be this … new political equilibrium."

Expanding Use of Grid-enhancing Technologies

Glick said utilities have not embraced grid-enhancing technologies (GETs) because the utilities' incentives are "backwards," encouraging them to invest in expensive transmission projects rather than smaller investments that could


R Street Institute's Devin Hartman | © *RTO Insider*


Former FERC Chair Richard Glick | © *RTO Insider*

produce savings for ratepayers.

"When I was at FERC, we looked at … the shared savings approach — we send some of the savings to consumers, send some of the savings to utilities — but it wasn't nearly enough to really get utilities to change their mindset," he said.

He noted FERC has an Advance Notice of Proposed Rulemaking *pending* that would require utilities to use dynamic line ratings under some circumstances (RM24-6). (See *FERC Gets Mixed Advice on How Quickly to Move on DLR Requirements*.)

"It seems to me a good idea — maybe the only idea that can actually work at … the federal level — to get utilities to engage sufficiently in GETs," Glick said.

"The only real policy progress that's been very concrete on this topic was *Order 881*," which requires transmission providers to use ambient-adjusted ratings, said Hartman. "That was sort of the lowest-hanging fruit, because … it's a uniform best practice. You don't need to do a cost-benefit breakdown in every little circumstance. It's just good utility practice.

"It's trickier, though, once you start getting into these other GETs, because they're not uniform best practices; they're very situation-specific, so you have to start attaching … bits of conditionality to this, and that's very difficult."

Hartman suggested FERC and the Department of Energy hold annual technical conferences to establish a record on the commercial viability of emerging GETs.

"I think you can then enable the ability for also some more bottom-up motivation, say an RTO framework where the PUCs and the consumer groups are really motivated," he said. "Then you start to have the laggards feeling the heat a little bit. … And then if people want to file complaints later, or FERC wants to do an investigation … knock yourself out. But I think we're only going to be able to squeeze so much juice out of rulemakings." ■

Van Welie Discusses the Challenges Markets Face in New England

By James Downing

WASHINGTON — In ISO-NE CEO Gordon van Welie's time running the grid operator, it has seen natural gas come to dominate generation in the region. An even bigger shift is underway now as state policies demand a grid increasingly powered by renewables.

The shift to natural gas led to cleaner generation than the mix 25 years ago, but it also has come with unexpected developments, van Welie said Oct. 23 at the S&P Global Nodal Trader Conference. "One of the big assumptions at the start of the market was that fuel will always be available," he added. "And of course, the fuel is not always available."

While natural gas generation is cheap enough most of the time to push other resources off the system, during winter cold snaps, the region struggles to attract enough of the fuel. Gas and electricity prices then skyrocket. With state policy shifting more heating and transportation demand onto the grid, winters promise to become more volatile.

"So, the big point, from a trading point of view, is much higher volatility than we've ever seen in the winter," van Welie said. "The second point is that emissions reduction will be seasonal. We will decarbonize the spring and the fall way before we decarbonize the winter, if ever."

ISO-NE sees negative prices in the shoulder seasons because of the proliferation of renewables. And van Welie said he expects that trend will grow. But serving a rising share of winter demand with 100% renewables would be costly because the reliability value of wind and solar declines as more resources are added to the grid.

Why This Matters

ISO-NE CEO Gordon van Welie talked about the challenges and trade offs New England faces as its grid decarbonizes and puts even more pressure on energy adequacy during the winter.

ISO-NE CEO Gordon van Welie giving a speech at S&P Global's Nodal Trader Conference in D.C. on Oct. 23. | © *RTO Insider*

Solar has a massive impact in New England, which van Welie described as a 42-GW system with 10 to 12 GW sitting behind the meter.

"If you can have firm, dispatchable, zero-carbon generation, the mythical 'DEFR' as New York invented this resource in their capacity expansion models — dispatchable emissions-free resource — you can really not only support reliability, you can dramatically reduce all that cost," van Welie said. "The problem is that resource doesn't exist today. Maybe SMRs will fulfill that role in the future, but for now, the balancing resource is natural gas."

Another economical answer is price-responsive demand because reductions can happen during winter peaks when producing power is most expensive. On top of price volatility issues, getting the last 15 to 20% of decarbonization will be the most expensive. The grid needs to expand to handle more renewables, which cuts energy market revenues for balancing resources needed to meet winter peaks.

"You need balancing resources to keep the lights on," van Welie said. "That money has got to come from somewhere, so that's the resource adequacy construct, and those constructs are under a lot of pressure right now."

ISO-NE expects the role of natural gas to grow in coming years as demand growth is outpacing the addition of renewable resources, which eventually will bring down emissions, though doing so all on their own could prove too costly for the region's future policymakers.

"Taking the last bit of carbon out of the system becomes increasingly expensive," van Welie said.

With affordability an ever present issue, policymakers might decide that 80% of the way to net-zero emissions is enough, he added.

The queue in New England today is dominated by renewables and batter-

Continued on page 11

Patton Calls on ERCOT to Operate its System Less Conservatively

By James Downing

WASHINGTON — ERCOT can ensure long-term reliability with its energy-only market, but it must operate its grid less conservatively for that to happen, said Potomac Economics President David Patton, the Texas grid operator's Independent Market Monitor.

ERCOT's ancillary services demand curves, which are part of the soon-to-go-live real-time co-optimization plus batteries (RTC+) initiative, imply a value of lost load of about $35,000/MWh, which is already well short of the $200,000/MWh implied by the one-day-in-10-years reliability standard, Patton said at S&P Global's Nodal Trader Conference on Oct. 24.

"What makes me pessimistic in Texas is that there are multiple levels of problems getting to an efficient shortage price," Patton said. "And most of it is driven by an extraordinarily conservative posture by ERCOT in how it operates the system."

The grid operator pays for excessive ancillary services and has demand response programs that kick in too early, both preventing it from reaching the needed scarcity prices that energy-only models rely on to attract investment, he added.

"I think until we get some degree of alignment between how ERCOT operates the system and the markets, we're going to be stuck in a state where it's nearly impossible to set efficient shortage prices," Patton said. "And, so, I don't know how it would motivate people to build dispatchable generation."

Plenty of DR is caused by the market, Patton said, with cryptomining data centers dropping offline when prices start to hit about $100/MWh, when the activity becomes unprofitable. But he said he is worried about DR from "outside the market" such as a residential DR program that will pay the load class to curtail at peak hours.

"The value of residential consumption is like $3,000, $4,000, $5,000/MWh, but the tightest net load hours like when

Why This Matters

ERCOT's Monitor flagged the grid operator's conservative operations since Winter Storm Uri as the cause of dampening price signals when new supply is needed to meet rising demand.

ERCOT imposes that and artificially cuts the load. … I'm guessing the price in those hours is going to be $50, $60, $70[/MWh]," Patton said.

That will serve to artificially hold the price down when the market would proceed to shortage pricing, he added.

ERCOT has grown its renewable energy production more than any domestic market, with 40 GW of wind, 33 GW of solar and 14 GW of batteries — and more of that is coming, said Keith Collins, vice president of commercial operations.

From left: EPAM Systems Managing Principal Rebecca Bollenbach, Potomac Economics President David Patton, CIM View Software CEO Steve Reedy, SynMax Vulcan Product Lead David Bellman and ERCOT Vice President of Commercial Operations Keith Collins at S&P Global's Nodal Trader Conference on Oct. 24 | © *RTO Insider*

"The peak loads don't really matter as much with the solar on the hot days," Collins said. "What matters is when the sun isn't there, and that's what we see in the load ramps, the net load that we see in the summer days. In the winters, we're seeing when the sun isn't up yet and the peaks are rising, that's the concern, and it's a big area of concern for us — the need to get dispatchable resources. That's where our dispatchable reliability reserve service is hopefully going to point us to focus on getting those types of resources."

Collins said the problem with scarcity pricing is that it will create incentives for all resources, when ERCOT needs more supply that can actually help balance renewables when their production drops.

Getting the Signals Right

Texas last debated major reforms for its wholesale market nearly five years ago after Winter Storm Uri led to widespread blackouts.

"After Uri, they looked at lots of options," Collins said. "Many options were crossed off the table and, so, we'll have to revisit some of those."

Patton pushed back on Collins' description of how scarcity pricing works, arguing it favors resources that can produce energy when the grid needs it most.

"If I have an unreliable unit that has a lot of forced outages, they're going to miss a lot of the shortages; they're going to make less money," Patton said. "A solar resource is probably not going to make any money getting shortages, because shortages are going to happen when the sun has gone down. If I have a wind resource, I'm not going to make very much money, because you're not going to have shortages when the wind is blowing."

Reliable, dispatchable resources will get high prices when the grid needs energy the most, so a key to getting energy-only models right is ensuring their signals align with that need, he said.

"You may say: 'We need other products to supplement that, because we have certain reliability needs that go beyond what our needs are in any one five-minute interval,'" Patton said. "So, I think we do need the dispatchable reliability service, but that's not going to be the answer to providing price signals."

Ideally, ERCOT would procure fewer reserves and let the system operate in a way that is more conducive to its energy-only design.

"There's no way to fix excessive conservatism with market design like that. At some point, you have to move from both ends," Patton said. "You have to operate the system in a manner that's more consistent with the true value of electricity. And then you have to identify market design issues that are undermining pricing as well, and hopefully then get to a point where your energy price is going to do most of the job in terms of motivating investment."

The Public Utility Commission of Texas told ERCOT to start operating more conservatively after Uri, Collins noted.

"There have been directions from the commission," Collins said. "Now, there was some recent discussion about perhaps revisiting that. We're happy to have that conversation. And if the commission were to direct us, we would take actions."

Patton argued that many of the conservative operations are coming from the grid operator itself because the PUC has approved only proposals to procure additional reserves that come from ERCOT.

"I think the conservative mindset is coming from ERCOT operations," Patton added. "Clearly, there's a sense that [the PUC wants] them to be conservative, but I don't think they're driving them to be this conservative." ■

Van Welie Discusses the Challenges Markets Face in New England

Continued from page 9

ies because that is what investors think can get built and what state policies are pushing. A significant resource the region was counting on was offshore wind, which has 15 GW under development.

"That's got a big question mark against it. It's been disrupted," van Welie said. "My guess is offshore wind has been knocked back at least a decade, and so does raise the question for the region, which is, where's the supply coming from in order to meet this demand that's projected?"

The questions around offshore wind have New England policymakers thinking about gas again, but that must be weighed against long-term decarbonization goals that could risk stranded costs. While the markets did well to bring investment onto the grid and shield customers from the risk of bad investments, ISO-NE is making major changes to its capacity construct to better deal with winter reliability issues.

"We need to move to a prompt, seasonal market with marginal accreditation and modeling of the gas constraints," van Welie said. "We'll be the first region to actively clear the capacity market by modeling a gas constraint."

If the markets are going to succeed at guiding New England through an affordable, reliable transition to a net-zero grid, as they did to a system dominated by natural gas, states must embrace the markets," van Welie said.

"Ultimately, the markets are a means to an end," van Welie said. "The states are the ones that created the markets. The states are the ones that can undo the markets. So, they need to have ownership and support for the market construct."

If states support a capacity market it could work. If they do not, they will find a way around it and meet their policy goals some other way, he added. ■

Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections

By James Downing

U.S. Secretary of Energy Chris Wright has directed FERC to initiate a rulemaking to accelerate the interconnection of large loads by asserting jurisdiction over end-use customers' connections to the grid for the first time.

"It is my view that the interconnection of large loads directly to the interstate transmission system to access the transmission system and the electricity transmitted over it falls squarely within the commission's jurisdiction," Wright said in a *letter* sent to FERC on Oct. 23 with an attached advanced notice of proposed rulemaking (ANOPR).

Asserting FERC's jurisdiction is in the public interest and in line with the Trump administration's goals of revitalizing American manufacturing and driving innovation in artificial intelligence (AI), both of which require extraordinary quantities of electricity and substantial investment in the transmission grid.

Wright used his authority under Section 403 of the Department of Energy Organization Act to direct FERC to initiate rulemaking procedures and consider the ANOPR on reforms to ensure the timely and orderly interconnection of large loads to the transmission system.

"In light of the unprecedented current and expected growth of large loads seeking to interconnect to the transmission system, and to provide open access and non-discriminatory access to the transmission system, it has become necessary to standardize interconnection procedures and agreements for such loads, including those seeking to share a point of interconnection with new or existing generation facilities (hybrid facilities)," the ANOPR said.

The document lays out four legal justifications for the regulatory change, the first being that large load interconnections are a critical component of open access transmission service that require minimum terms and conditions to ensure non-discriminatory transmission service.

Second, the interconnection of large loads is a practice that directly affects FERC-jurisdictional rates, and the Federal Power Act has vested the regulator with exclusive authority to ensure wholesale rights are just and reasonable.

Why This Matters

The secretary of energy asked FERC to assert jurisdiction over large loads, which could help data centers and others with speed-to-market concerns, but would upend the current practice where states oversee customers' connections to the grid.

The ANOPR's third justification argues it will not impinge on state authority over retail sales because FERC will not exert jurisdiction over any retail sales to the large load.

"Similarly, nothing in the proposed reforms governs the siting, expansion or modification of generation facilities," the ANOPR says. "Authority over expansion or siting of generation facilities remains reserved to the states."

Fourth, any contrary view of the proposed reforms conflicts with the Federal Power Act's core purpose that grants FERC exclusive jurisdiction over transmission in interstate commerce and large loads connecting to the grid to obtain service benefit from that.

Any new rules should apply only to transmission facilities, consistent with FERC's seven-factor test. The new rules also should apply only to customers with 20 MW of load, or for hybrid facilities where the load is greater than 20 MW.

DOE's ANOPR suggests studying large loads and new generation together where possible as that would allow for efficient siting and minimize the need for network upgrades. Load and hybrid facilities should be subject to study deposits, readiness requirements and withdrawal penalties.

The studies should be done based on injection and withdrawal capacity available and be required to install system protection facilities to stay at or below those levels.

Curtailable load and hybrid facilities should have their studies expedited and the ANOPR asks whether requirements around curtailability can be included in the interconnection study process, or by other means.

Any generator that enters a partial suspension to serve large load will have to go through a reliability-must-run type study that will consider system conditions, including load growth, at least three years after the suspension.

FERC will have to justify its departure from long-standing rules that gave states jurisdiction over customer interconnection, which despite decades of orders on restructuring markets it has never claimed.

"Thus, while we believe in most cases there will be identifiable local distribution facilities subject to state jurisdiction, we also believe that even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users," FERC said in its Order 888 in 1996.

FERC Commissioner David Rosner posted on X that he was happy to take up Wright's proposal and that dealing with the issues has bipartisan support on the commission.

"I am excited to work with my colleagues on Secretary Wright's proposal," he *posted*. "Getting large load interconnection right is a generational opportunity that is key to winning the AI race, reshoring American manufacturing, and keeping electricity reliable and affordable for everyone."

Former FERC Chair Mark Christie said in an interview Oct. 24 that the ANOPR overlapped with the ongoing debate at FERC over co-location of load, which he wanted to get a final rule out on, but was unable to secure enough votes before stepping down in August.

Shutterstock

The devil is in the details, and many questions will be answered as FERC works through a rulemaking process, but Christie warned that the change in jurisdiction could lead to problems.

"It's going to have a monumental impact certainly on state authority to govern interconnection and set the terms of interconnection, and also it's going to have a monumental impact on the states' ability to maintain the integrity of their integrated resource planning process (IRP)," Christie said.

The order directs FERC to process large load interconnection requests with 60 days, which could mess up load forecasts on which IRPs rely. In RTO states, it will have the effect of removing existing generators from the market and putting upward pressure on prices to the extent it encourages co-location, and the issue of load forecasting also is pertinent due to the use of demand curves in capacity markets.

"That demand curve is set by load forecast," Christie said. "So, if load is basically unpredictable, because FERC is now saying every single large load customer has to be interconnected within a short time frame, that's going to potentially drive up the demand curve in the PJM capacity market."

The main questions FERC will have to answer are what the rule change would mean for reliability, what it will mean for costs and cost allocation and whether it can claim an authority previously reserved for states.

"I think they're all questions at this point, not conclusions," Christie said. "I want to emphasize that they're all questions at this point, not conclusions."

Speaking at S&P Global's Nodal Trader Conference, NRG Vice President of Regulatory Affairs Travis Kavulla said that hopefully the order moves the ball forward on dealing with large loads.

"Obviously all of these loads are connected at relatively high voltages, basically to the transmission system," Kavulla said. "So, I have sometimes puzzled why state-regulated utilities acting in what seems to be solely in keeping capacity would be the arbiters of how that load gets on the system."

One of Texas' big examples is that it does not have separate authorities for transmission and distribution, which has helped make it a major market for hyperscale data centers, he added.

A key difference with Texas is that it is operating an intrastate market and it is not having its authority potentially usurped by the federal government, Christie said.

NARUC spokesperson Regina Davis said in an email that the proposal was being reviewed by the group and its state regulator members so it could not comment on specifics.

"Naturally, the matter of adequate load growth is a priority for NARUC and its members," Davis said. "We engaged with FERC on the Joint Federal-State Task Force on Electric Transmission, which has evolved into the new Federal and State Current Issues Collaborative exploring cross-jurisdictional issues."

Davis added that "the ANOPR points to data centers as one of the drivers of load growth, which is the focus of our Demand Roundtable that convenes hyperscalers and mega users in dialogues to discuss the critical issues surrounding increased demand.

"Achieving the grid reliability and flexibility needed to accommodate growing demand will require input and collaboration with state regulators and NARUC looks forward to working with FERC and other stakeholders to ensure the grid can meet future demand," Davis said. ■

Trump Appoints Swett to Chair of FERC

President Donald Trump has named Laura Swett chair of FERC, the commission *announced* Oct. 24.

Swett was sworn in as a commissioner Oct. 20. Her term expires June 30, 2030.

"I am honored to serve as chairman of FERC and grateful for President Trump's confidence in me to advance America's energy priorities at such a critical moment in our nation's history," Swett said in a statement. "I look forward to working with my colleagues and FERC's excellent staff to continue the commission's crucial mission of ensuring reliable and affordable energy for all consumers."

Swett takes over from David Rosner, who said at FERC's open meeting the previous week that he would be happy becoming a commissioner again. Rosner was something of an interim chair, holding the office for only a few months after Mark Christie left the commission in August.

Swett was confirmed alongside David LaCerte to open seats on the commission Oct. 7. The two are Trump's first nominees in his second term in the White House. (See *Senate Confirms Swett, LaCerte to Open Seats on FERC*.) LaCerte has not yet been sworn in as of press time.

Laura Swett | © *RTO Insider*

Swett is no stranger to FERC, having been a staffer for former Chair Kevin McIntyre and Commissioner Bernard McNamee. She has been litigating FERC law for 15 years, which includes representing utilities, transmission owners and pipelines, most recently at Vinson & Elkins.

She received her bachelor's degree from the University of Virginia and law degree from Georgetown University. She lives in Virginia with her family. ■

— James Downing

ACORE Grid Forum Panelists Scorn Tx Permitting Process, Express Hope

By Amanda Durish Cook

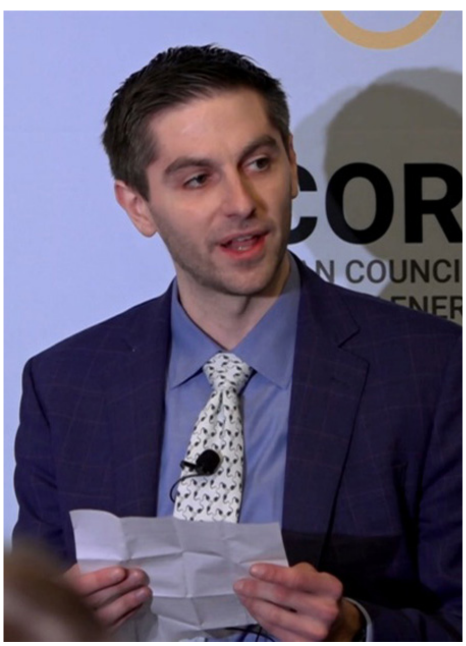
> **Why This Matters**
>
> One panelist at the ACORE Grid Forum read from a U.S. intelligence agency's 1944 'Simple Sabotage Field Manual' to illustrate how circuitous transmission permitting in the U.S. has become.

Speakers at the American Council on Renewable Energy's annual Grid Forum weren't afraid to use strong words on the ineffectiveness of the U.S. permitting system but were bullish that it's fixable.

The permitting environment in the U.S. is so "inhospitable" that it results in "dark matter" — beneficial transmission lines that don't come into existence because weary developers don't bother to attempt them, Daniel Palken, of philanthropy organization Arnold Ventures, said at ACORE's annual meetup Oct. 23 in D.C.

Palken read from the "Simple Sabotage Field *Manual*" drafted by the U.S. Office of Strategic Services (the predecessor agency to the Central Intelligence Agency), which was distributed to Europeans in German-occupied territories during World War II to disrupt the Nazis.

The manual details "innumerable simple acts which the ordinary individual citizen-saboteur can perform," it reads. It describes how adopting a "noncooperative attitude" can lead to damage indirectly. "A noncooperative attitude may involve nothing more than creating an unpleasant situation among one's fellow workers, engaging in bickerings, or displaying surliness and stupidity."



Arnold Ventures' Daniel Palken reads from the Simple Sabotage Field Manual at the ACORE Grid Forum on Oct. 23. | *ACORE*

Palken said these simple acts include:

- never permitting shortcuts that could expedite decisions;
- making longwinded speeches littered with anecdotes and patriotism;
- referring matters to intentionally large committees for further study and consideration;
- bringing up irrelevant issues in discussion;
- haggling over precise wording in minutes and resolutions;
- attempting to relitigate matters decided upon in previous meetings;
- frequently advising caution and warning against haste;
- second-guessing decisions and questioning whether the committee held jurisdiction in the first place.

"It should be obvious to anybody in this room that is a very sound description of the transmission planning process, the process by which transmission lines are paid for and cost allocated, and then the process by which they are finally permitted and built in this country," Palken said.

"We're, in short, sabotaging ourselves and our ability to build the large-scale infrastructure that we need."

Elizabeth Horner, of law firm ArentFox Schiff, said part of the challenge of federal efforts to streamline transmission permitting is that jurisdiction is spread across multiple House and Senate committees, FERC and the Department of Energy.

Horner said Republicans and Democrats should come to an agreement on their respective "end goals" of permitting reform, which are often the same, though messaging to their constituents is different.

Despite the ongoing federal government shutdown and Capitol Hill staffers not being paid, closed-door discussions and drafts are still being circulated to make inroads on permitting improvements, she said.

"Do not treat the shutdown as a reason to stop advocacy," Horner told the audience.

Horner said she was hopeful that Congress could pass a bill in 2026 that would build on the past five years of incremental permitting changes.

Palken agreed, saying the shutdown is "immaterial" to the momentum around transmission permitting changes.

Senator Optimistic on Permitting Improvements

U.S. Sen. Shelley Moore Capito (R-W.Va.), chair of the Environment and Public Works Committee, said the committee is still at work to try to make permitting "faster, fairer and less expensive."

"We've only really nibbled around the edges," Capito said of previous congressional efforts to streamline permitting. She noted the stops and starts of legislation trying to cut red tape, with the unsuccessful START Act and RESTART Act and the currently on-pause SPEED Act (*H.R.4776*) in the House of Representatives.

"If there's skepticism in the room as to whether we can make it again this year, I certainly understand that," she said. "You might be rolling your eyes, like, 'does she really think this can happen?' I am an optimist. I always think everything can happen; everything good can happen."

But Capito told the audience not to expect a detailed timetable from her on bill passage and admitted that she thought "we were going to reopen the government three weeks ago."

Capito said permitting laws must be fair to "every type of project" and listed solar, wind, geothermal, gas pipelines, coal and nuclear. She said project developers should have confidence that they can move forward and "not have to look over your shoulder" in the fears that a new presidential administration could terminate projects.

"We've seen that happen on both sides," Capito said. She added the government needs to "prevent the swings" of scrapping the Keystone XL pipeline under President Joe Biden and then discarding "Sen. [Sheldon] Whitehouse's" (D-R.I.) offshore wind farms under President Donald Trump. She said any new law needs "specific, locked-down permitting language" to cut out loopholes that are openings to getting projects canceled.

Capito also called for tight timelines on judicial review, so projects aren't caught in a "circular firing squad" of litigation.

U.S. Rep. Gabe Evans (R-Colo.) — a co-sponsor of the SPEED Act — said permitting reform will be a "massive" undertaking requiring buy-in from five congressional committees involved in permitting.

He said simpler permitting is desperately needed, comparing China's recent installment of 500 GW on its grid to the U.S.' current, 1,100-GW system.

"If we can't build things in the United States, we are going to get our butts kicked by our foreign competitors, and so permitting reform is absolutely critical to be able to speed up that timeline," Evans said.

Evans said currently, 80% of permits are ultimately issued as-is for big infrastructure projects requiring environmental reviews that have been bogged down in years of litigation.

FERC Chair David Rosner joked he would give a "safe-place, sitting-government-official" answer to whether he believed permitting improvements are necessary: "I will be really delighted to implement any bill that Congress passes and the president signs.

"But with the FERC hat off, as an American citizen, I will say I think it takes too long to build all sorts of infrastructure in this country," Rosner said. "I think it's really obvious, and I'm very hopeful we can find bipartisan, durable solutions to that."

ACORE CEO Ray Long (left) and Sen. Shelley Moore Capito (R-W.Va.) | *ACORE*

Transmission the 'Biggest Antidote' to Load Growth

ACORE CEO Ray Long said the country's outdated permitting process takes up to 17 years to approve major transmission lines and four to five years for other critical energy infrastructure.

"That delay is more than a bureaucratic frustration. It's a roadblock to affordability, reliability and national competitiveness," Long said.

Long said the U.S. cannot power the 21st century with a permitting system designed for the "1970s and before." He cited Grid Strategies' December 2023 report concluding the U.S. power grid could require an additional 120 GW of new capacity by 2030, the equivalent of adding the capacity for 12 New York Cities.

Long said the energy industry needs to "think big and act quickly" to accommodate the artificial intelligence boom, new factories and clean energy.

"Everyone in this room understands that every mile of new transmission powers jobs, innovation, prosperity. It strengthens communities, connects technologies and helps ensure that American remains a global leader in energy, in manufacturing," Long said.

Palken said since FERC issued Order 1000 in 2011, zero new interregional transmission lines have been completed, and most areas of the country have failed to select transmission lines through regional planning processes. Though MISO has had some success in planning regional transmission lines, the RTO essentially ignores half its footprint (the South region) and has no plans to better connect its Midwest and South regions, he said.

Transmission is the "biggest antidote" to unprecedented load growth, Palken said.

"Forty-nine states right now are convulsing, trying to figure out how to accommodate roughly 3% load growth. One state — roughly — has been doing 2 to 3% load growth for the last decade while keeping rates completely steady, in inflation-adjusted terms, while beating all the blue states at their own clean energy deployment goals. This state is of course Texas," he said.

Palken said Texas features a better interconnection process than in other regions, easier siting laws and more straightforward permitting, in addition to transmission planned through its Competitive Renewable Energy Zones. Though Texas mostly isn't beholden to FERC or the National Environmental Policy Act, Palken said ERCOT is an "instructive" example for Congress. ■

Republicans Celebrate Changed Energy Policy at AFPI Summit

By James Downing

Why This Matters

The Trump administration has left its mark on energy policy and officials highlighted some of the major changes at a think tank's meeting.

WASHINGTON — It has been almost a year since President Donald Trump won a second, nonconsecutive term, and that election's impact on energy policy was evident at the America First Policy Institute's Global Energy Summit.

AFPI Vice Chair of Energy & Environment Oliver McPherson-Smith proclaimed the meeting — held at the Waldorf Astoria Washington DC (formerly a Trump International Hotel) — "the anti-COP," in that it was celebrating fossil fuel and not the talk about net-zero emissions that will dominate the U.N. Climate Change Conference in November in Belém, Brazil.

"I won't be at COP 30 this year," Energy Secretary Chris Wright said at the AFPI event Oct. 22. "I think there's a reasonable chance I will be at COP 31 because we want to bring our arguments to our opponents."

Wright argued that the Trump administration is starting to push back against maximalist climate arguments that have been used to try to control entire industries.

"It's real; it's an issue," Wright said. "But it's just not remotely close to a top five or top 10 issue in the world, but we treat it like this existential threat to the planet. Nothing, nothing in the data says as much, but no one calls that out."

Major U.S. allies have said they agree that the focus should be on energy security and affordability, but they tell Wright they cannot say that aloud, he claimed.

"They're realizing this justification for big government and the replacement for religion — it isn't unchallenged anymore, and it doesn't stand up under challenge," Wright said.

Wright said the other side of the argument on climate change is still winning, but he predicted that would not last.

"We've got the minority, but we're right, and it's easier to win an argument when you're right than when you're wrong," Wright said. "They have more people; they have more momentum; but they don't have math and facts and humans on their side. We do, and we're going to win."

Wright celebrated that the Trump administration was recently *able to stop* the International Maritime Organization from implementing the first global carbon tax when it adjourned before voting on a measure that would have mandated decarbonization of international shipping. The group had agreed to the standard in April, but then the administration found out about it, Wright said.

"I remember I talked to one of the energy ministers from a big, allied country of ours (might even speak the same language as us), and as I spoke to this great gal, she said, 'Well, we know it's a forgone conclusion. It's going to pass anyway. We want to be in the tent, because that'll be better than out of the tent.' Well, I wouldn't assume that's going to pass."

Wright worked the phone and eventually Trump *posted* on Truth Social slamming the proposal. In the end, the effort was enough to spike the tax for a year at least.

The change is being felt in domestic policy as well, with Continental Resources founder and Trump donor Harold Hamm saying at the event that the Biden administration wanted to put the oil and gas industry out of business, but now Trump is taking the opposite approach.

"We've got an administration that is actually leading," Hamm said. "Making all these changes that are necessary to get America back on track, to make America great again."

Going forward, Hamm said he would like to see the permitting process changed so that eminent domain for pipelines is handled by the federal government and the requirements to perform environmental impact statements are slashed.

He also warned that the oil and gas industry was oversupplied by foreign competitors in OPEC, mainly Saudi Arabia.

"They are doing it all for market share," Hamm said. "We've seen this before, right? It's not going to last very long, folks. You're looking at about a 10-year window here that suddenly will change, and once you peek out and start over the hill, guess what? It's going to be a little tough to get it turned around next time."

Horizontal drilling gave the world cheap energy, but that was a one-time event, and going forward, getting more supply from new technologies will not be easy, he said. As in the power sector, the next big thing for oil and gas is growing demand from data centers.

"Their fuel of choice, what's going to drive them, is natural gas," Hamm said. "That's the best thing. So, we're a little bit early on that curve. They're building them, and when they get online, folks, they're going to be the hell to draw on gas. And, so, you know that's going to be a big bright spot."

While Congress has already enacted major changes using Republican votes alone, House Energy and Commerce Committee Chair Brett Guthrie (R-Ky.) said he hoped to move bipartisan permitting legislation. That will be important to winning the artificial intelligence race because the U.S. already has the brain power and the capital to compete.

"What's holding it back is the regulatory side," Guthrie said. "We have to get the right regulatory side, but also, more importantly than anything, access to energy. Energy is everything in AI."

The issues around permitting have limited the impact of Democrats' policies, with Guthrie noting that the Inflation Reduction Act allocated $42 billion for broadband, but not one cent had been spent when Trump re-entered office. Now, with the "abundance agenda" taking root in Democratic politics and aimed at actually building infrastructure, Guthrie said he sees a possible opening.

"Maybe there's an opportunity, we're hoping, for us to come together to do a bipartisan permitting reform so that we can move electrons," he said. ■

Retribution Fears Impede Wildfire Mitigation, FERC Conference Speakers Say

By Henrik Nilsson

Oregon Public Utility Commission Chair Letha Tawney called for a less punitive data-sharing regime around wildfires, saying at FERC's Wildfire Risk Mitigation Technical Conference that liability fears impede the industry from understanding the root causes of fires.

Speaking in the first wildfire panel Oct. 21, Tawney said "it is difficult to find consistent data about the different wildfires," because wildfires are investigated by different federal and state agencies. This can impede the industry's understanding of trends around ignitions and frequency of wildfires, according to Tawney. (See *FERC Conference Speakers Emphasize Planning, Collaboration*.)

Oregon Public Utility Commission Chair Letha Tawney | *FERC*

Another challenge is data sharing on "near misses" — events that don't escalate into wildfires but still trigger alerts. Those events are important to understand because they can identify issues that would not have been captured otherwise, such as equipment failures or issues with vegetation management, Tawney said.

"Not all states capture that, and it can be often confidential information," Tawney said. "So, work around reporting would be helpful. But in many states, you have a liability regime ... folks are very sensitive about cause codes and releasing information early. It can take a long time to investigate."

"This is where I think moving toward a safety culture approach where we're capturing near misses in a way that does not punish the actor, but allows us to capture root cause analysis, [makes sense]," she added.

The Nuclear Regulatory Commission and the aviation industry have these types of reporting regimes in place, Tawney said. The power industry must capture near misses and "spread the lessons back out similarly."

"If we aren't capturing those near misses, we don't know if we're doing better," Tawney said. "We don't know if ... all the mitigations we're deploying and the billions of dollars that we're spending are really making our communities safer. We think they are. It's an intuition, in many cases. So, finding ways to capture that data, protect the reporter from punishment outside of egregious behavior, I think, is really an important way that the sector needs to move forward to face the challenge."

Tawney was joined on the panel by leaders from the federal government, the Western Electricity Coordinating Council and the South Texas Electric Cooperative (STEC).

Clif Lange, general manager at STEC and representing the National Rural Electric Utilities Cooperative, said capturing and sharing near-miss data "is incredibly important."

Lange agreed with Tawney that people are hesitant to share data because of potential liabilities. He said the industry should create an environment "where people can freely share that information without ... fear of retribution."

"And I think as an industry, you're able to advance and develop those mitigation programs more effectively and more efficiently and more quickly," Lange said.

Standards

FERC hosted the wildfire conference in light of an executive order signed June 12 by President Donald Trump. The order calls for the federal government to work with state and local leaders to streamline "wildfire capabilities to improve their effectiveness and promoting commonsense, technology-enabled local strategies for land management and wildfire response and mitigation."

The panelists also discussed safety standards around public safety power shutoffs (PSPS) and grid hardening.

Kristin Sleeper, deputy undersecretary for natural resources and the environment at the Department of Agriculture, said the agency is "looking forward to working with utilities and FERC on standards for power safety shutoffs."

Why This Matters

Wildfires have gone from mainly a Western issue to now being a challenge across the country, and the industry is grappling with implementing new wildfire mitigation tools.

PSPSs are implemented differently across the country, Sleeper said. Wildfire used to be mainly a Western problem for five months out of the year. Now it affects the entire nation year-round, she said.

"We're seeing fires in New Jersey, in different parts of the East," Sleeper said. "So more uniform standards on how we can sort of prevent some of the ignitions from power lines."

Sleeper added that the agency wants to "understand the utilities' interest in hardening standards and grid resilience once a wildfire has burned through." All too often, communities fail to improve resiliency when building back after a fire, and USDA wants to be "an active partner" in figuring out standards for hardening, Sleeper said.

Agency coordination is crucial, Lange said in agreement with Sleeper. However, he cautioned against implementing uniform standards.

Texas, for example, varies greatly just within the state, Lange noted.

"You've got the piney woods of East Texas that require a completely different set of practices than you would use to manage and mitigate fires as compared to the areas of West Texas, where you really have wide open lands, very little fuel out there to actually ignite."

Power shutoffs should not be mandated, he added, noting that those can lead to "incredible hardships."

"We need to make sure we've got a tool set but allow folks to be able to pull the right tool out of the toolbox when they need it, such that we get effective wildfire mitigation as a result," Lange said. ■

Promise and Challenge of Advanced Nuclear Power Examined

RFF Webinar Centers on Industry's Path from Vogtle to SMRs

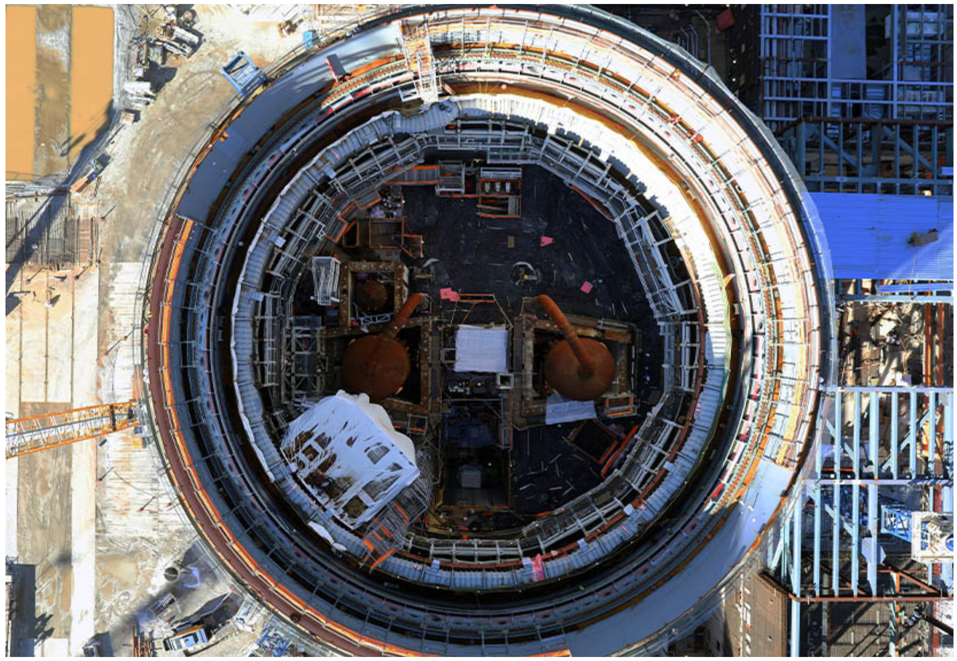
By John Cropley

New nuclear generation holds promise for the U.S. and its energy sector if its challenges can be overcome, panelists said during a *Resources for the Future webinar*.

The consensus was that regulatory, financial and policy support are important components of the process by which this can happen.

John Williams, Southern Nuclear | *Resources for the Future*

RFF President Billy Pizer opened the Oct. 21 conversation with John Williams, senior vice president of technical services at Southern Nuclear, which developed Plant Vogtle Units 3 and 4, the only U.S. nuclear construction project to reach commercial operation in decades.



Plant Vogtle Unit 4's containment vessel is viewed from above during construction in February 2020. | *Georgia Power*

With its delays and cost overruns, Vogtle illustrates the problems facing first-of-a-kind projects, Williams said, but also the benefits that can accrue for second-of-a-kind projects.

The project was plagued with unforeseeable problems such as the Fukushima disaster, the bankruptcy of its contractor and the COVID pandemic, Williams said, but there also were the predictable first-mover difficulties, particularly with Unit 3.

"We had challenges as we were building a new supply chain for a new technology," he said. "And then workforce — it had been 30 years since we had built a new nuclear plant from scratch in the United States. So our workforce, we didn't have that muscle memory that they have in other parts of the world, where they have been building on a more regular frequency."

Why This Matters

The discussion provided multiple perspectives on the hurdles facing any significant increase in U.S. nuclear power generating capacity, as well as the benefits of clearing those hurdles.

Unit 4 was in some ways a second mover, and the effect showed, Williams said: It cost nearly 20% less than Unit 3 to build, and commissioning took half as long.

How many more Vogtles would it take, Pizer asked, to reach that "Nth of a kind" balance where things can move fast and predictably, without cost overruns and delays?

Six to 10, Williams estimated.

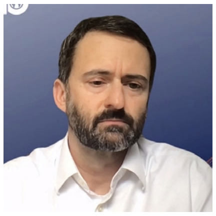
The momentum has flagged, however. Heavy construction was completed at Vogtle in mid-2023, Williams said, and a workforce now experienced at building nuclear reactor complexes went its separate ways to build data centers and auto factories.

Williams said Vogtle 3 and 4 cost about $11,000/kW of nameplate capacity in present-day dollars, but if the next several projects were built in close succession around the same Westinghouse AP1000 reactor, the cost would gradually drop.

"By the time you come down that Nth of a kind curve, now you're looking at $6,000 to $7,000 a kilowatt," he said. "By taking a pause, we will absolutely have to do some relearning. The sooner we get started, the better off we'll be."

Karen Palmer, senior fellow in RFF's electric power program, asked when all this nuclear generating capacity in the planning stages might start sending power onto the grid.

Matt Bowen, senior research scholar at Columbia University's School of International and Public Affairs, ran through a partial list of the many development efforts vying for market leadership positions and said: "I sort of think the better question is, who if any of these entities is going to build something at an acceptable cost that can then be deployed a bunch of times in the 2030s and 2040s to make a sizable contribution to the U.S. energy portfolio, let's say over 50 GW.



Matt Bowen, Center on Global Energy Policy, Columbia University School of International and Public Affairs | *Resources for the Future*

"It's a little too early to say how these are all going to turn out."

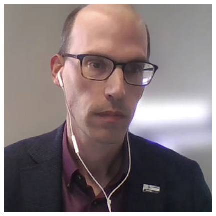
Bowen said he is confident, however, that future gigawatt-scale projects could proceed with fewer delays and cost overruns than the two recent U.S. examples, Vogtle and the canceled V.C. Summer.

Alan Ahn, Third Way | *Resources for the Future*

Alan Ahn, deputy director for nuclear at Third Way, said small modular reactors are promising because of their smaller footprint, which is expected to lower cost and increase versatility. Lower cost could facilitate financing , which has been a challenge for the nuclear industry.

"I think the reality in terms of hurdles going forward is that we're still at a first-of-kind stage with these technologies. Matt went over some of those issues at length," Ahn said. "There's definitely light at the end of the tunnel. I think the challenge now is maximizing the potential of these technologies by building them at scale, maturing supply chain and reaching commercial maturity."

Mixing into this crowded environment are a number of states promoting nuclear development, such as New York, whose governor has ordered the New York Power Authority to develop at least 1 GW of nuclear capacity.



Erich Scherer, New York State Energy Research and Development Authority | *Resources for the Future*

Erich Scherer, director of strategy at the New York State Energy Research and Development Authority, said NYSERDA is not exactly new to the sector, having evolved from New York's atomic agency.

But that was 50 years ago, and nuclear power has evolved greatly since then.

"So learning lessons is very much at the top of mind, both in terms of learning at the project level, but also in terms of learning from best practice, policy experience," he said. "I'm also going to recognize that, I think, as a reality check, [there] just aren't that many lessons to learn yet."

Vogtle is a treasure trove of lessons, Scherer said, but it is an exception: Only a few of the many other reactor designs and business models being developed have even begun construction, and only a few states have put forth a comprehensive policy strategy.

New York is very aware of the risks involved in being a first- or second-mover, he said. "What's really important in our mind is the possibility of cooperation between states, and so as we develop our master plan, we are also very much conscious that that's not an effort in isolation. And New York state is part of initiative called the First Mover Initiative together with 10 other states."

This presents the chance to build a multistate order book and a pipeline that spreads the risks more broadly, Scherer said.

President Donald Trump, meanwhile, is roiling the regulatory environment in which all this would take place, demanding faster approvals and streamlined oversight.

Bowen said a lot of regulations are outdated and ripe for efficiency reviews, and there are opportunities to responsibly speed the process. But the Nuclear Regulatory Commission is being blamed unfairly for so few new reactors coming online in the past 30 years, he said.

Ahn addressed another challenge: the fuel supply chain. The U.S. gets its uranium from mines in other countries, he said, and while they can ramp up production, "I think the real challenge and bottleneck is with uranium conversion and enrichment, where producers need to invest in and execute expansions to their industrial capacity.

"In and of itself, that dependency on foreign fuel supply chains is not an insurmountable issue. We've operated our nuclear fleet on fuel converted and enriched overseas for very long time."

The potential problem is that many other nations want to ramp up nuclear power generation, he said, setting up a strain on the supply chain, and that a significant share of the supply chain is still controlled by a potentially uncooperative country: Russia.

"I think particularly on nuclear fuel, there is need for coordinated, cooperative, international actions between the U.S. and its allies and partners," Ahn said. ■

Trump's TVA Nominees Reject Privatization

By Michael Brooks

Each of President Donald Trump's nominees to the Tennessee Valley Authority's board of directors said they did not support the privatization of the utility or selling its assets, as feared by some environmentalists.

Speaking at their confirmation hearing before the Senate Environment and Public Works Committee on Oct. 22, Mitch Graves, Jeff Hagood and Randy Jones each simply said "no" when asked by Sen. Ed Markey (D-Mass.) whether they supported TVA's privatization. Florida Public Service Commissioner Arthur Graham said, "I think there's absolutely no reason to do anything different here."

When asked by Markey to agree not to "sell off any portion of TVA's service region" or infrastructure assets, the nominees mostly answered to the senator's liking.

"I do not see any reason to sell any of TVA's assets off," Jones said, which Graham echoed after Markey said: "that was the correct answer."

Graves said, "I don't think that's the board's decision," to which Hagood agreed.

The nonprofit group Appalachian Voices had urged senators to question the nominees on privatization based on comments Trump made during his first administration. The TVA board has lacked a quorum for months after the president fired three of its members. (See *Nonprofits Warn of Potential TVA Privatization Ahead of Board Hearings*.)

The committee will vote on advancing the nominees to the Senate floor Oct. 29.

All four spoke about TVA's importance in keeping electricity affordable for its customers. Graves, a member of the Memphis Light, Gas & Water board, and Hagood, a Knoxville-based attorney, each emphasized preserving it as a local institution.

When questioned about meeting load growth, each emphasized the importance of nuclear power, with Hagood calling it TVA's "best hope."

"We need a sense of urgency" on nuclear, agreed Jones, an insurance executive who also serves on the Guntersville Electric Board in Alabama.

Graham said small modular reactors are "key" to meeting increased demand. But first he wanted "to make sure the numbers people are talking about [in terms of gigawatts] are legitimate. I mean, is this a pipe dream, or is this actually going to come true? I believe it is," but the board needs to verify the anticipated demand through its integrated resource plan, he said. "I saw what happened in Georgia with Vogtle … and no one wants to be the next one going down that path."

Sen. Mark Kelly (D-Ariz.) suggested power purchase agreements for large loads to protect customers from rate hikes created by the increased demand. Graves said he "100% agreed" with Kelly "that it cannot be on the backs of ratepayers."

Each also agreed they would consider creating a separate rate class for large load facilities like data centers.

"This is all we're about now, is data centers," Jones said in agreement. "But what's it going to cost to supply the power for them? And what if they leave five years from now and we're left holding the bag?" ■

TVA headquarters in Chattanooga, Tenn. | *bomazi, CC BY 2.0, via Wikimedia Commons*

Brookfield Nearing Deal for Unfinished S.C. Nuclear Reactors

Santee Cooper Looking to Sell V.C. Summer Units 2 and 3

By John Cropley

Santee Cooper is entering final negotiations with Brookfield Asset Management over two partially built nuclear reactors left in limbo for the past eight years.

The companies expect to reach a memorandum of understanding after a six-week period to examine resumption of construction and talk with potential power customers.

The developments *announced Oct. 24* are the latest indication of the strong interest in nuclear power and are a remarkable turnaround for what had been one of the U.S. nuclear industry's costliest failures.

Work on V.C. Summer Unit 2 and Unit 3 was halted after extensive delays and cost overruns, yielding a patchwork of reinforced concrete and mothballed equipment at a cost of more than $9 billion. Four executives eventually went to prison for their misdeeds in the project, *the last of them in November 2024*.

In January, spurred by the renewed interest in nuclear power's steady emissions-free power, Santee Cooper put out a request for proposals for sale of the project. (See *Santee Cooper Seeks Buyer for Unfinished Nuclear Project*.)

The state-owned public power and water utility said it received more than 70 initial expressions of interest and 15 formal proposals. Its board of directors approved the letter of intent with Brookfield on Oct. 24.

The Unit 2 reactor containment structure is shown at the V.C. Summer Nuclear Station in South Carolina. | *South Carolina Governor's Nuclear Advisory Council*

Why This Matters

The zombie project could produce 2.2 GW of power if completed.

The centerpiece of the deal is the two partially built Westinghouse AP1000 reactors. Their combined 2.2-GW rating is a potentially lucrative asset in an era of rising electricity demand and higher electricity costs.

Importantly, Santee Cooper maintained the equipment already on site during the eight years it sat idle.

"The state of the units, and the fact that they use the same Westinghouse AP1000 technology that is now operating in Georgia and overseas, make these assets very attractive to the nuclear power industry," Santee Cooper CEO Jimmy Staton said in the news release.

Westinghouse will continue to be involved in the completion of the two reactor units, Staton said. Brookfield is majority owner of Westinghouse.

Of interest to ratepayers — who had to help foot the bill for what became known as Nukegate — the Brookfield deal is built on private funding.

"Brookfield came to Santee Cooper with a proposal that set out the path to turn our prior nuclear investment into lasting value for our customers and all South Carolinians," said Santee Cooper Board Chair Peter McCoy.

"Our goals include completing these reactors with private money and no ratepayer or taxpayer expense, delivering financial relief to our customers and gaining significant additional power capacity for South Carolina. Brookfield's proposal would do just that, and the company has the financial capability to stand behind its proposal." ■

EDAM Participants Exploring Potential New Western RA Program

Discussions Follow NV Energy's Decision to Leave WRAP

By Elaine Goodman

Following a recent announcement that it plans to withdraw from the Western Resource Adequacy Program, NV Energy said it is discussing a potential new resource adequacy program with other participants in CAISO's Extended Day-Ahead Market.

Speaking during an Oct. 21 prehearing conference before the Public Utilities Commission of Nevada, Lindsey Schlekeway, market policy director for NV Energy, described the program as "a high-level concept" and said there are no formal agreements yet.

The conference was regarding NV Energy's energy supply plan update for 2026/27. Tim Clausen, NV Energy's vice president of regulatory affairs, said the company would file a request with the PUCN to join the EDAM as an amendment to the company's energy supply plan.

NV Energy announced in June 2024 that it plans to join EDAM rather than SPP's Markets+. (See *NV Energy Confirms Intent to Join CAISO's EDAM*.)

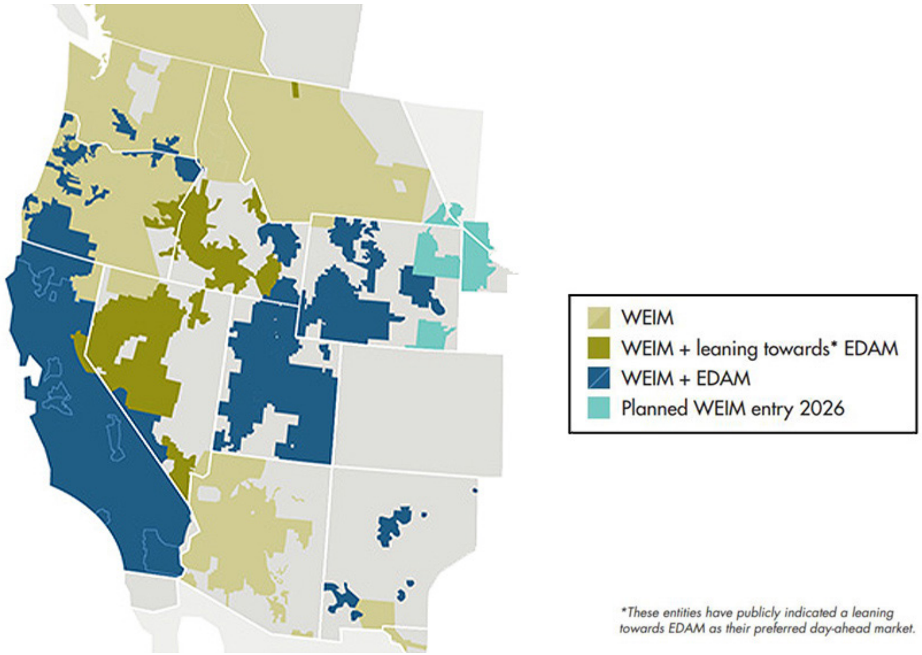
As part of an update on the supply plan, Schlekeway filed written testimony explaining the company's decision to withdraw from Western Power Pool's WRAP. She detailed five "critical issues," including "steep penalties for capacity deficiencies identified seven months before the compliance season." (See *NV Energy to Withdraw from WRAP*.)

Another issue is that all load-serving entities in Markets+ will be required to participate in WRAP.

"While expanding participation can enhance regional reliability, it may disadvantage entities that prefer to remain in the Western Energy Imbalance Market … or transition to the Extended Day-Ahead Market," she wrote.

In contrast to Markets+, EDAM won't require its participants to belong to an organized resource adequacy program. Instead, EDAM will use a resource sufficiency evaluation to ensure participants' RA going into the day-ahead and real-time time frames to meet their own needs without depending on others.

NV Energy will continue to watch WRAP's development and remain open to future participation if the five issues are addressed, Schlekeway said.



Current EDAM participants | *CAISO*

Why This Matters

WRAP is facing participant uncertainty ahead of an Oct. 31 deadline to commit to the program's first binding phase.

"We will continue to follow WRAP, but we will also follow other avenues if others want to discuss resource adequacy in other forums in the West," Schlekeway told Commissioner Tammy Cordova, the hearing officer in the case.

Schlekeway said that even after submitting a withdrawal letter, NV Energy can remain active in WRAP through participation in WPP's Resource Adequacy Participant Committee, for example.

Cordova asked what would happen if the PUC directed NV Energy to participate in WRAP. "We can always re-enter the program," Schlekeway responded.

Contacted after the prehearing conference, Schlekeway referred further questions on a potential Western RA program to an NV Energy spokesperson, who said the company had no further comment.

Rebecca Sexton, chief strategy officer for WPP, told *RTO Insider* that the organization is "aware of discussions about creating an alternative resource adequacy program."

Sexton hopes that any entities that choose to leave WRAP will stay involved with the program's governance during the two-year exit window and later decide to commit to binding participation. With binding-phase commitments from 11 participants and the potential for others to join, she said WRAP will launch "with a significant footprint with substantial load and resources and geographic diversity."

Critical Time for WRAP

The discussion of an alternative resource adequacy program comes at a critical time for WRAP.

An Oct. 31 deadline is looming for participants to commit to the program's first binding phase in winter 2027/28. Of the 11 members that have so far committed to WRAP's first binding season, all but one are expected to join Markets+.

But some members say they need more time. PacifiCorp has asked WPP's board of directors to allow WRAP participants to defer their decision to commit to the program's binding phase by at least one year. (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.)

Portland General Electric also sent WPP a *letter* seeking a one-year deferral of the binding season. PacifiCorp and PGE have signed implementation agreements with CAISO to become EDAM's first participants in 2026.

In response letters to PacifiCorp and PGE, WPP Board Chair Bill Drummond said delaying the binding phase "would have a detrimental effect on reliability for the region, including undermining confidence in WRAP data and modeling, limiting program compliance and preventing us from unlocking the full benefits of the program."

The Imperial Irrigation District, which is slated to join EDAM in fall 2028, has staff participating in discussions of a potential new Western RA program.

"Momentum has started, communication is active, and kickoff meetings have begun," IID spokesperson Robert Schettler told *RTO Insider*.

The district wants to be fully aware of, and ready to use, the full menu of RA options, said Schettler, who noted that IID is a balancing authority that is a net exporter most of the year.

IID isn't currently pursuing WRAP membership, although it is an option in the future, he said.

When contacted by *RTO Insider*, a PacifiCorp spokesperson did not directly answer a question about whether the company has been participating in discussions of a new RA program.

"As part of prudent utility operations, PacifiCorp routinely evaluates opportunities to benefit customers, and resource adequacy is a significant focus of that process," the spokesperson said in an email.

PacifiCorp is considering its participation in the WRAP binding phase ahead of the Oct. 31 deadline, the spokesperson said, and plans to continue its involvement in the program regardless of the decision. ■

NV Energy Files Request to Join EDAM

Updated Analysis Forecasts $93M in Annual Benefits

By Elaine Goodman

NV Energy has asked Nevada regulators for permission to join CAISO's Extended Day-Ahead Market — a request that, if approved, would fill in a central piece of the market's footprint.

The company filed the request with the Public Utilities Commission of Nevada on Oct. 22 as an amendment to its 2025-2027 Energy Supply Plan. NV Energy's target date for EDAM entry is fall 2028.

The PUC is expected to issue an order within 135 days.

Factors in NV Energy's decision include its positive experience with CAISO's Western Energy Imbalance Market (WEIM), the company said in its filing.

And larger economic benefits are expected from joining EDAM rather than SPP's Markets+. A Brattle Group study, updated in October, projected that NV Energy would save $93.1 million a year by joining EDAM, relative to participating in WEIM alone. In contrast, joining Markets+ would increase annual costs by an estimated $7.3 million.

NV Energy also pointed to better transmission connectivity with the anticipated EDAM market footprint compared to that of Markets+.

Another factor the company cited was the governance of EDAM as enhanced by West-Wide Governance Pathways Initiative and California's AB 825, "including CAISO's ability to respond more expeditiously to events with targeted, expedited stakeholder processes."

California Gov. Gavin Newsom signed AB 825 into law in September, allowing CAISO to transition the governance of its markets to an independent "regional organization." (See *Newsom Signs Calif. Pathways Bill into Law*.)

Why This Matters

The addition of NV Energy to EDAM would give the market footprint a strategically located balancing authority.

NV Energy headquarters | © *RTO Insider*

NV Energy also said it prefers certain EDAM market design features, including its resource sufficiency test, congestion rent allocation, virtual bidding, greenhouse gas accounting and voluntary participation in Western Power Pool's Western Resource Adequacy Program (WRAP).

The company announced in August that it plans to withdraw from WRAP and revealed on Oct. 21 that it has been working with other EDAM participants on a potential alternative Western resource adequacy program. (See related story, *EDAM Participants Exploring Potential New Western RA Program*.)

In October 2023, the Nevada PUC opened a docket regarding regional market activities in the Western Interconnection. As part of the proceeding, the commission approved a report outlining the criteria to be addressed in a utility's application to join a regional market. NV Energy's application to join EDAM follows its announcement in May 2024 that it planned to join EDAM rather than SPP's Markets+.

Other entities on board with EDAM are PacifiCorp and Portland General Electric, which have formally committed to joining in 2026. The Balancing Authority of Northern California, Los Angeles Department of Water and Power, Public Service Company of New Mexico (PNM) and Turlock Irrigation District have signed agreements to join in 2027; Imperial Irrigation District plans to join in 2028.

Arizona G&T Cooperatives, BHE Montana and Idaho Power have indicated they're leaning toward EDAM.

NV Energy's entry would add a substantial chunk of territory to the EDAM footprint, between California entities and PacifiCorp West to the west and PacifiCorp East to the east. Idaho Power would be directly to the north, while PNM extends the footprint deeper into the Southwest.

"Joining [EDAM] positions Nevada at the heart of the Western grid, connecting the Southwest and the Northwest to efficiently share affordable, reliable and flexible power across the region," said Emilie Olson, Nevada lead at Advanced Energy United.

Olson said that joining a robust regional energy market is essential to NV Energy for controlling costs while tapping into a diverse regional energy mix.

CAISO said NV Energy's filing is "a significant step forward" in its plans to join EDAM.

"We are eager to work with NV Energy and all the EDAM entities to deliver the full range of benefits, including improved resource sharing and meaningful cost savings for consumers across the West," the ISO said in a statement. ■

PSE Launches DLR Pilot Project with Norwegian Tech Firm

By Henrik Nilsson

Puget Sound Energy announced a partnership with Norwegian tech company Heimdall Power to install monitoring devices on 100 miles of transmission lines, stating the technology will help optimize the capacity of existing equipment.

PSE and Heimdall Power have installed 75 monitoring devices called "Neurons" on the utility's transmission lines in western Washington under a dynamic line rating (DLR) pilot project that will run through summer 2026. The sensors can help increase grid capacity and power delivery for PSE's 1.2 million customers by collecting real-time data on electrical current, line temperature, sag, wind speed and weather conditions, according to an Oct. 22 news release.

"This is an exciting first step for PSE to understand and capture the value of dynamic line ratings," Alex Brotherston, principal engineer on PSE's grid modernization team, told *RTO Insider* in an email. "With load growth, rising costs, aging infrastructure and long project timelines, it is critical that we leverage this kind of technology to increase the safety and efficiency of our grid."

The pilot project "will allow us to observe the real-time conditions around our system and, when conditions are right, transfer more power through existing lines," Brotherston said. "This in turn can ease congestion and give our operators more flexibility to respond to market or system constraints."

Citing numbers from the U.S. Department of Energy, Brotherston said DLR can increase transmission capacity by 10 to 30%. PSE conducted a preliminary study using historical weather data, which showed that the utility's pilot lines could see a capacity increase of up to 50% under the right conditions, Brotherston added.

Heimdall installed the DLR devices using both autonomous drones and traditional installation methods, according to the news release.

The partners said this is the largest deployment of DLR sensors in the U.S. and they will provide a continuous data stream, allowing PSE to increase transmission capacity "based on actual operating conditions rather than conservative estimates."

Brotherston said the sensors can provide insights on line conditions during extreme weather scenarios, which can assist PSE in understanding how much power each line can safely handle.

A Heimdall drone installing a monitoring device on a PSE transmission line. | *Puget Sound Energy*

Notable Quote

"With load growth, rising costs, aging infrastructure and long project timelines, it is critical that we leverage this kind of technology to increase the safety and efficiency of our grid."

- Alex Brotherston, principal engineer on PSE's grid modernization team

"This allows us to proactively adjust load ahead of adverse conditions or avoid overloading lines during emergency rerouting," Brotherston added.

PSE also hopes the devices can assist in incorporating more renewable energy on the grid.

"When we are armed with more knowledge about the capacity of our lines, we can more strategically route power around our system, which gives us the necessary flexibility to site new renewable energy sources, or more efficiently utilize the renewables already on the system," Brotherston said. "In the future, this could look like a wind farm being able to generate at full power instead of being constrained by the capacity of the transmission system, or fewer infrastructure upgrades required to site a new solar facility."

PSE declined to disclose the financial details for the pilot project, saying sharing costs could affect future contracts "as we move toward full-scale implementation or work with vendors on similar future projects."

PSE said the pilot project is part of the utility's efforts to modernize the grid and enhance resilience on its network. The utility will test the technology through summer 2026, then analyze the data to determine how to implement dynamic line ratings using the devices. ■

CPUC Hears Cacophony of Protests to Proposed PG&E Rate Increases

By David Krause

Why This Matters

A general rate case determines a large portion of electricity and gas rates for customers of a utility.

Key organizations across California voiced strong opposition to Pacific Gas and Electric's proposed rate increases that are under review at the Public Utilities Commission.

Protesting organizations include the California Farm Bureau Federation, the California Community Choice Association and the Environmental Defense Fund, among many others.

The proposed rate increases are part of PG&E's 2027 general rate case *application*, which was reviewed at an Oct. 22 public forum with CPUC officials. PG&E submitted its current general rate case application on May 15, and the commission plans to approve adjusted rates in May 2027.

Critically, PG&E's application does not include costs associated with recent wildfire mitigation work, community rebuilding projects, billing system upgrades, undergrounding, electricity procurement, fuel and purchase power, or costs to own and operate the Diablo Canyon Power Plant, the CPUC said.

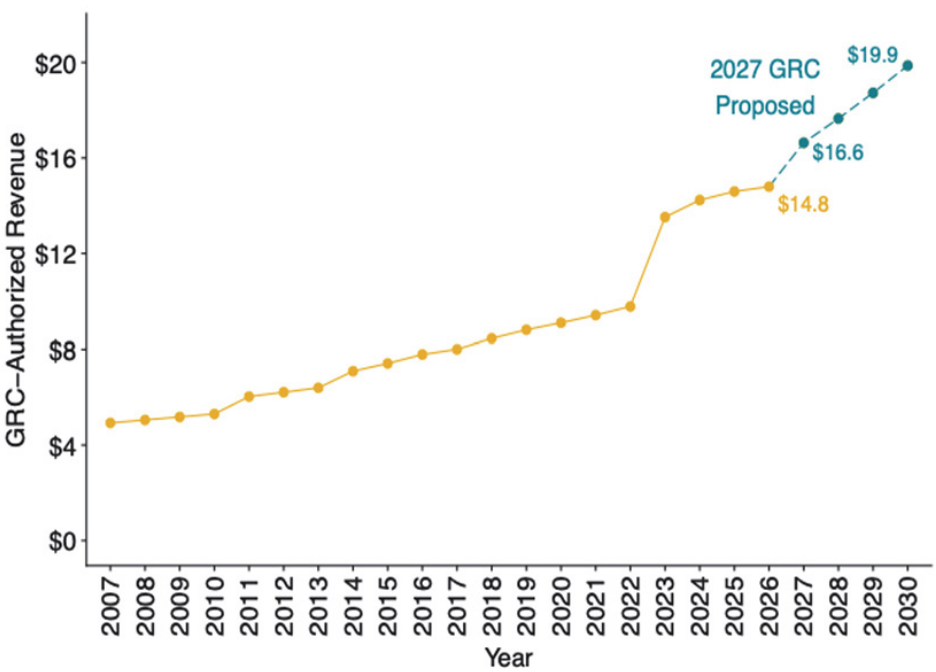
Increases in prior PG&E rate case applications have been driven by wildfire mitigation work, safety work and inflation, PG&E said in its application.

Proposed increases in the 2027 general rate case application are about 8% in 2027 and about 6.1% in 2028, 2029 and 2030.

In 2027, the rate change would increase the average residential customer's gas and electric bill by about 3.6% compared to a bill in 2025. Electric bills would increase by about 5.2%, while gas bills would decrease by about 0.6%.

The average residential bill would increase by about $9.94/month in 2028, $10.50/month in 2029 and $11.08/month in 2030.

PG&E requested $72 billion over four years to fund its operations and investments, and the application controls a little more than half of PG&E's overall revenue, CPUC Commissioner John Reynolds said at the Oct. 22 public forum.



PG&E's 2007-2026 authorized and 2027-2030 proposed revenues (in billions of dollars) | *CPUC Public Advocates Office*

"I am mindful that when PG&E pledges that rates will remain stable for years to come, the rates are currently unaffordable for many residents in the state," Reynolds said at the forum. "Stable rates will not offer [relief] to those who are struggling to pay their bills."

Displeased Organizations

In *comments* to the commission, Kevin Johnston, representative of the California Farm Bureau Federation, said PG&E's rate application contained "a number of assumptions and misdirection" that minimize what continue to be "significant increases" built upon "years of skyrocketing increases" in revenue requirements.

"The authorized revenue requirement in 2017 was $8 billion. The adopted revenue requirement in 2026 was $15.4 billion. A 92% increase in nine years," Johnston said. "Customers want transparency, not spin."

CalCCA added in *comments* that PG&E's rate case application raises "critical questions concerning cost shifting."

The group is concerned specifically with PG&E's request for $2.45 billion of capital investments between 2027 and 2030 in the company's hydroelectric generation fleet. Many of the hydroelectric assets have outlived their expected lifespan, and PG&E is not required to relicense these assets, CalCCA said.

EDF said in *comments* that it's concerned with PG&E's capital forecasts for setting initial rates and the lack of information about data center forecasts in its territory. ■

Large Loads Slow to Interconnect in ERCOT

RTC+B on Track, and More Discussions from the TAC

By Tom Kleckner

ERCOT stakeholders gathered in Austin on Oct. 22 for a Technical Advisory Committee meeting, only to have a large-load discussion break out.

And with good reason. Staff told TAC members that they are tracking over 200 GW in large-load interconnection requests, primarily from data centers and cryptocurrency mining. Over 130 GW of requests (a 182% increase) have been added to the queue in just the past 10 months. However, only about 6.5 GW have been energized or approved for energization, with an additional 4.7 GW being studied.

That led stakeholders to question whether ERCOT has placed a moratorium on energizing large loads.

Consultant Bob Wittmeyer, chair of the Large Load Working Group, said that is not the case. "More loads have been approved to energize [in West Texas] than we can handle, but those loads are not yet operational, and it will be a while until they are," he said, repeating what was said at the LLWG's meeting Sept. 19.

However, Evan Neel, with data center developer Lancium, said the discussion during that meeting was not clear, leading to uncertainty within the market.

"In fact, that following Monday, there were some market research firms that published headlines of the sort that

Why This Matters

ERCOT is tracking over 200 GW in large-load interconnection requests, but only about 6.5 GW have been energized or approved for energization. At the same time, it says there is no moratorium on energizing large loads, but that they must clear certain requirements first.

Lancium's Evan Neel questions ERCOT's large-load policies. | *ERCOT*

'ERCOT pulls the plug on data centers,'" Neel said. "They were citing explicitly things that were said during that meeting," Neel said. "Obviously that is a concern when we're talking about bringing investment to the state."

ERCOT has cited studies that indicate it could lose at most 2,600 MW of load under certain operating conditions, without exceeding the post-contingency frequency limit. Staff said in a June *market notice* it is "essential" that they have accurate large-load models to assess grid stability risks, saying recent operational events demonstrate "the dynamic models currently representing many of these [loads] do not reflect their actual dynamic performance."

"We've seen conversations around numbers of about 2,600, but the market notice points to a bunch of historical events that have not been anywhere close to that," Neel said.

Another, more recent *market notice* bypassed the stakeholder process and addressed large loads potentially energizing on the system without having cleared "certain important hurdles."

The notice established a new approval process requiring confirmation of all necessary modeling and telemetry is in place before a large load's energization.

The process is effective immediately and applies to any studied large load, regardless of the planning process used to evaluate interconnection's reliability.

"This is something we don't do willy-nilly," Chief Regulatory Counsel Nathan Bigbee said. "Sometimes we may not have time, or we may decide that we don't have time, to pursue a revision request for the stakeholder process in order to address the reliability risk.

"ERCOT ultimately has a statutory obligation to ensure the reliability of the grid," he reminded stakeholders. "In some cases where there isn't sufficient time to pursue a protocol revision or other guide revision, we believe it's incumbent on us to address that risk. Sometimes that requires establishing policy on an interim basis through a market notice."

RTC+B Project Eyes Dec. 5

ERCOT's Matt Mereness said the Real-time Co-optimization + Batteries (RTC+B) project continues to be on the right track as its Dec. 5 implementation date nears.

"It looks like it'll be a fairly smooth transition without having to take special procedures," he told TAC during his regular update to members.

The project is in its third and final phase, with the focus on go-live. A required live production test to ensure effective frequency dispatch and control, involving almost 100 qualified scheduling entities and additional marketers, is scheduled for Oct. 30, and a *cutover workshop* is set for Nov. 13.

Mereness said staff have been evaluating historical data to determine potential ancillary service demand factors, the hourly parameters for each service type that indicate an assumed deployment (energy reservation) based on demand forecasts, intermittent renewable resources and other system conditions. These factors are used in the reliability unit commitment (RUC) studies.

The RTC+B Task Force held an *in-depth meeting* Oct. 27 to delve into ERCOT's analysis and planned values. It was part of a tripleheader meeting that day.

The switchover will take place between 11:59 p.m. Dec. 4 and 12:01 a.m. Dec. 5 as the market begins dispatching energy and ancillary services every five minutes in real time.

Members Show Their College Colors

Members were encouraged to show their college spirit, and some did, wearing jerseys or shirts that exhibited their academic ties.

The meeting soon devolved into good-natured ribbing between Texas Exes and Former Students from Texas A&M. (As good Aggies know, there are no ex-Aggies, only Former Students.)

TAC Chair Caitlin Smith, a University of Texas alum with Jupiter Power, was quick to needle American Electric Power's Richard Ross, a proud Aggie. "Richard Ross told me the theme of the month is 'Hook 'em Horns!'" she said.

Ross, who usually sets monthly themes for TAC and SPP stakeholder meetings, snapped to attention. "That's not true! That's not true at all!" he said. Caught without a theme, he instead recounted SPP staff's use of the term "trauma bond."

"That's when new staff joins the [stakeholder] meetings and they have the anxiety because they oftentimes get candid feedback and discussion," Ross said. Turning to ERCOT's Elizabeth Morales, bedecked in a UT T-shirt for her first TAC meeting, he said, "Elizabeth, this your trauma bond with TAC. I will share with you that that is one ugly shirt you're wearing."

ERCOT's Matt Mereness, UT alum | *ERCOT*

"It's a beautiful burnt orange shirt," Smith responded, coming to Morales' defense.

Reliant Energy Retail Services' Bill Barnes wore a football jersey from the Colorado School of Mines bearing his son's No. 27. A sophomore, Max Barnes led the School of Mines' *72-14 win over Adams State* on Oct. 18 with 201 rushing yards.

ERCOT's Jake Pedigo had to step in when a fellow alumnus of the University of North Texas couldn't remember the school's slogan. "We are the Mean Green Eagles," he said, "and it's 'C'mon Green, Get Mean.'"

RUC Opt-out Window Expanded

TAC unanimously endorsed, with two abstentions, a protocol call change (*NPRR1285*) that expands the current RUC opt-out window to incent self-commitment, increasing capacity available to the market at lower expense and reducing RUCs and associated costs.

The endorsement came despite an objection from the Independent Market Monitor.

"On a principal level, it doesn't really improve self-commitment," said the IMM's director, Jeff McDonald. He agreed with staff's assertion that the change increases flexibility for a generator and its settlement options, but he said that "by increasing the amount of flexibility you have for your settlement options, it would actually decrease the incentives for self-commitment for resources who believe that they might be near the margin of being needed or not needed."

Dave Maggio, ERCOT's commercial operations principal, said NPRR1285 eliminates an extra two hours from the lead time before an opt-out decision, which becomes a telemetry function.

"[I] just wanted to make sure it's clear that it's not a reversion back to what we had previously," he said.

TAC's combination ballot, or consent agenda, included the *annual major transmission elements list*, five NPRRs, a Nodal Operating Guide revision (NOGRR) and a system change request (SCR) that, if approved by ERCOT's board, would:

- *NPRR1263*: remove the accuracy testing requirements for coupling capacitor voltage transformers.
- *NPRR1280*: establish a regional planning group review process for proposals to permanently bypass an existing series capacitor or un-bypass a series capacitor previously designated as permanently bypassed.
- *NPRR1293*: clarify the "Update Network Operations Model Production Environment's" milestone dates.
- *NPRR1294*: incorporate the other binding document "Demand Response Data Definitions and Technical Specifications" into the protocols, standardizing the approval process.
- *NPRR1299*: clarify and clean up language related to the emergency response service program, including a data file produced at the end of the procurement process using code managed entirely within ERCOT's Demand Integration group. The file is manually produced and must be posted manually, which is affected by weekends and holidays.
- *NOGRR279*: modify the monitoring equipment installation deadlines established by *NOGRR255* (High Resolution Data Requirements) to Jan. 1, 2029, consistent with NERC standard PRC-028-01 (Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources), and clarify that synchronized resources with standard generation interconnection agreements executed prior to July 25, 2024, have 12 months after their commercial operations date to comply with the new equipment standards.
- *SCR831*: modify the network model management system, operational data management system, topology processor and the modeling-on-demand system to incorporate short-circuit modeling data for maintaining models built by the system protection working group. ■

Texas Gov. Abbott Appoints 4th Commissioner to PUC

Texas Gov. Greg Abbott has appointed Morgan Johnson to the Public Utility Commission, adding a fourth member to the five-person panel.

Morgan Johnson | *Morgan Johnson via LinkedIn*

Johnson, a deputy general counsel for the Office of the Governor, was appointed Oct. 23 and sworn in. By being appointed while the Texas Legislature is out of session until 2026, Johnson can be seated immediately without confirmation.

"The electric, water and telecommunications industries are complex and have an enormous impact on the lives of millions of Texans," Johnson said in a *statement*. "I look forward to working with my fellow commissioners and [PUC] staff ensuring affordability and reliability of these life critical services."

Before joining the governor's office, Johnson was a senior counsel at the Texas Commission on Environmental Quality. She also worked as an attorney at McGinnis Lochridge.

Johnson holds a bachelor's degree in finance from the University of Texas at Austin and a law degree from the South Texas College of Law. Her term expires Sept. 1, 2031. ■

— Tom Kleckner

Texas Gov. Greg Abbott has appointed Morgan Johnson to the PUC. | *© RTO Insider*

Texas AG Opens Civil Investigation into ERCOT

By Tom Kleckner

ERCOT has told its market participants that the Texas Attorney General's Office has served the grid operator with a civil investigation demand (CID) in connection with an ongoing investigation.

The CID seeks market and operations data that includes protected information and ERCOT critical energy infrastructure information necessary for the AG's Office to "evaluate potential violations of applicable law," the grid operator said in an Oct. 22 *market notice*.

ERCOT said it will immediately disclose the requested information "as required by applicable law." It assured market participants that it will "take steps to maintain confidentiality" by labeling confidential information and relying on statutory information protection requirements.

In an emailed statement, ERCOT said it would not comment on pending legal matters.

This is not the first time AG Ken Paxton's office has issued a CID to ERCOT. His office *launched investigations* into the grid operator and several other entities that he said "grossly mishandled" the grid

ERCOT's Austin headquarters | *© RTO Insider*

during the disastrous Winter Storm Uri in 2021.

"We will get to the bottom of this power failure, and I will tirelessly pursue justice for Texans," Paxton said at the time.

The AG's Office did not respond to questions about the current CID or results of the 2021 investigations. It also hasn't posted a news release about the new investigation.

RTO Insider contacted several market participants. None of them were aware of the investigation.

One theory is Paxton is conducting a "fishing expedition" to bolster his U.S. Senate campaign with some positive news.

The investigation could be linked to a recent lawsuit the Public Utility Commission *filed in June* against Paxton. The PUC was seeking to block the release of data on cryptocurrency miners, saying public disclosure could lead to acts of terrorism against the facilities.

A 2023 *state law* required cryptocurrency loads greater than 75 MW to register with the PUC by February 2025. The PUC rebuffed several media outlets when they asked for data on the registrations; the outlets then appealed to the AG's Office.

According to *The Texas Tribune*, the AG's Office in May sided with the media outlets. An assistant said the PUC "failed to demonstrate" the requested information was specific enough to aid terrorists.

Like ERCOT, the PUC said it would not comment on "pending legal matters." ■

ERCOT Wants Better Information, Clarity from Large Loads

By Tom Kleckner

ERCOT has told the Texas Public Utility Commission it has prioritized a project in 2026 to gather information from the more than 200 GW of large loads in the interconnection queue, a 227% increase in a year's time.

Data centers account for nearly three-fourths of the queue, ERCOT said. Crypto mining, which constituted half of the queue last year, is down to 1.3%.

ERCOT staff *told* commissioners during their Oct. 23 open meeting that the industry's developers and customers are stating their needs for certainty and transparency. The concern is two-way, as most everyone realizes all 200 GW will not show up.

The project will begin after real-time co-optimization is deployed in the market in December.

"That's just going to help the [interconnection] process in moving forward and giving us clear information," Kristi Hobbs, vice president of system planning and weatherization, told PUC commissioners.

To that end, Hobbs said the grid operator wants to re-evaluate whether large loads should have a direct relationship with ERCOT. She said staff proposed a protocol change in 2022 that would increase their relationship with the end-use customers but said it received pushback during the stakeholder process.

"We pivoted to the utilities having the relationship," Hobbs said. "We work with the utilities and what we find is that it hampers transparency … [for] the large loads and the developers being able to understand where ERCOT is in the process."

She said having better relationships with the end-use customers would help with their concerns.

"At the end of the day, I don't think there's one solution. It's going to be a combination of all of these things," Hobbs said, referring to updated ERCOT operating procedures as the bridge between grid improvements and changes to large loads' systems and operations.

"In the middle, there's us improving our operating procedures and our planning processes so that we can all meet that same goal for reliable power in the state," she said.

First up is ensuring the large loads can meet voltage ride-through requirements.

"When you had several thousand megawatts of large loads on the system, it was not as much of a concern," Hobbs said. "In recent years, we've continued to see the number of events where you see faults on the system. We've got to be able to protect the system from that, especially as we look ahead to hundreds of gigawatts of potential load on the system. We need to make sure we have the right requirements in place and we're taking the proper precautions to protect their businesses as well as their neighbors."

PUC Chair Thomas Gleeson said his foundational issue is to provide certainty to loads in the interconnection process. He provided anecdotal evidence of one large load that entered the process in the first quarter of 2024.

"As of yesterday, it still was kind of in limbo about where they were and how long the process might take," he said. "I think it's incumbent on us to talk through that and see if we can improve upon that to give these customers some sense of how long the process may take, understanding that there are a number of variables and unknowns."

Hobbs responded by saying ERCOT has looked at how its neighboring grid operators' processes. She said large loads must show a commitment before they're included in a study.

"The study process is really just a short part. It's the transmission build and physics doesn't change that," she said. "Here in Texas, we can do it in three to five years, where in other regions, it's six to 12. I think Texas is well positioned to be able to welcome those loads in the future."

Why This Matters

With more than 200 GW of large loads in its interconnection queue, ERCOT has told the Texas Public Utility Commission it plans to begin a project in 2026 to gain more accurate information and clarity from developers and end-use consumers. The project will begin once real-time co-optimization has been deployed in December.

ERCOT's Kristi Hobbs briefs the PUC on the grid operator's large-load interconnection queue. | *AdminMonitor*

CenterPoint Settlement Corrected

The PUC signed off on CenterPoint Energy's *settlement* with Houston and other cities for nearly $1.1 billion in system restoration costs eligible for recovery and securitization after Hurricane Beryl and other storms in 2024 (*58028*, *58252*). The commission approved the order during its Oct. 2 open meeting but held off from signing it until the requested legal consulting and non-consulting expenses could be corrected. The settlement estimated those costs at $2.2 million when they were nearly $2.9 million. Gleeson authorized the expenses to be recovered in CenterPoint's next ratemaking proceeding. ■

IESO Seeks to Manage Risks in Long Lead-time Procurement

By Rich Heidorn Jr.

IESO is seeking to reduce risks in its procurement of long lead-time (LLT) resources by reserving the right to reject proposals that are too expensive and allowing the ISO and generation developers to cancel deals in the first few years.

IESO created the LLT procurement in response to stakeholder feedback that energy storage resources such as compressed air and pumped hydro require longer planning cycles than the four-year lead times for resources offering in the pending Long Term 2 (LT2) procurement.

The ISO plans to seek 600 to 800 MW of capacity and up to 1 TWh of energy from resources requiring at least five years of lead time in a solicitation expected about Q4 2026. The first drafts of the capacity contract and request for proposals (RFP) were *posted* Oct. 20.

"It's possible that there will be future [procurement] windows," IESO's Danielle D'Souza said in an engagement session Oct. 21, the fourth stakeholder meeting on the procurement. "I think that will depend on outcomes of this single procurement window, and … subject to [the Ministry of Energy and Mines'] direction."

D'Souza said the ISO has not yet closed debate on any design issues in the procurement. "However, we do intend very soon to begin closing design elements" to focus on unresolved issues, she said.

Why This Matters

The procurement will accommodate long-duration energy storage resources that can't qualify for the ISO's long-term solicitation.

Reserve Price

IESO proposes to use reserve prices — a confidential price threshold — to ensure it doesn't pay too much for energy or capacity in the solicitation.

The ISO said the thresholds will be based on inputs including prices in the first window of the LT2 procurement and any differences in the obligations between LT2 and LLT resources.

Akira Yamamoto, director of regulatory and market policy for TransAlta, said he understood why IESO wouldn't want to disclose the reserve prices but said it should provide guidance to help developers understand whether they should participate in the procurement.

"If you publish that methodology, that would actually give some insights without giving that true value. I think you need to give some indication to [whether your project has] no chance of actually getting procured," he said. "Essentially, the ISO giving some indication that 'Don't waste your time if you're too expensive.'"

Highview Power is building the first commercial-scale liquid air energy storage plant in the United Kingdom, the 50-MW/300-MWh Carrington project near Manchester. | *Highview Power*

Termination Provision

The ISO also proposes a termination option that could be exercised by IESO or the project developer in the first two or three years after the contract date.

If IESO exercises termination, it would return the developer's completion and performance security ($20,000/MW of maximum contract capacity with a minimum of $350,000 and a maximum of $15 million) along with a fixed payment to cover a portion of development costs. If the developer chooses to terminate, IESO would retain a portion of the completion and security and there would be no payment for development costs.

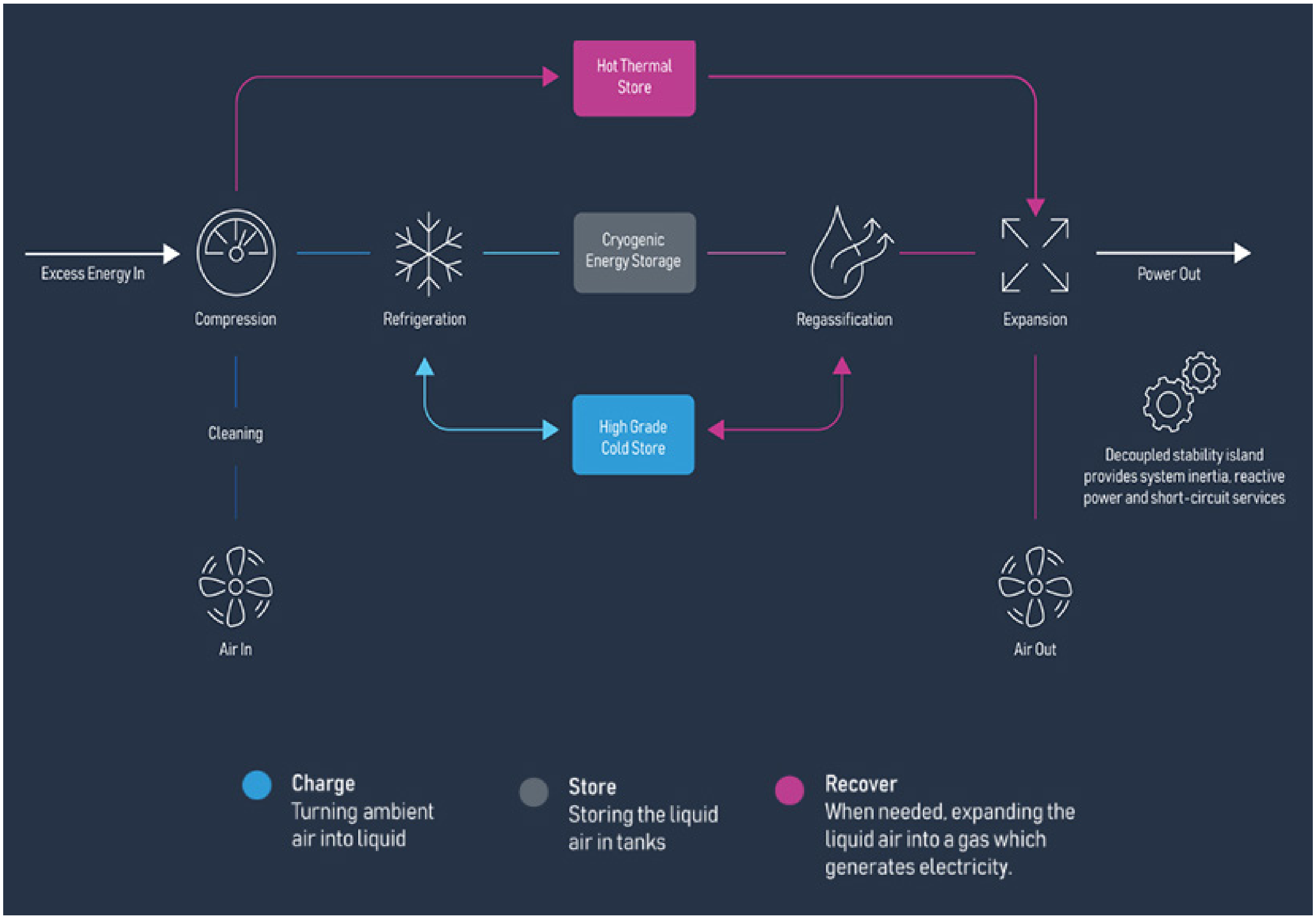
If neither party terminates, the full completion and performance security of $35,000/MW would take effect.

Yamamoto questioned why IESO wouldn't cover all of the development costs if it initiates the cancellation.

"I just think that that makes this a pretty unattractive type of procurement to be involved in if [IESO] changes their mind on the project and decides not to pay you for the cost that you're actually incurring," he said.

Dave Barreca, IESO's supervisor of resource acquisition, said IESO is attempting to address "pitfalls that have been seen previously with similar arrangements in older procurements."

"[We] absolutely recognize that that



Liquid air energy storage uses electricity to compress air until it becomes a liquid, saving the thermal energy in a high-grade thermal store. | *Highview Power*

could be an issue," he acknowledged, saying IESO wants a policy "that can work for developers, while … limiting the liability [to IESO] and the difficulty of assessing … costs that have been spent to date."

Eligibility

IESO plans to use a 40-year contract for both energy and capacity procurements.

The capacity stream will be open to new electricity storage facilities of at least 50 MW — up from 1 MW in the LT2(c-1) RFP — that are able to deliver their contract capacity for at least eight hours and use an eligible long-duration energy storage (LDES) technology. The facility must begin commercial operations between five and eight years after the contract date.

100-MW Cap on Class 2 LDES Technologies

The draft RFP identifies as eligible "Class I" LDES technologies compressed air energy storage and pumped hydro storage, based on their technology readiness.

Two newer technologies were defined as "Class II" LDES technologies and will be limited to a maximum procurement of 100 MW:

- liquid air energy storage, which uses electricity to compress air until it becomes a liquid, saving the released thermal energy in a high-grade thermal store; and
- *pumped thermal storage*, which converts electricity into heat, which is stored as thermal energy and later converted back into electricity through reversible thermodynamic cycles.

IESO said the 100-MW cap would "limit the risks related to procuring less proven technologies and encourage participation from a diverse set of eligible LDES technologies."

The ISO also may require an independent engineering report detailing "project scope, permitting path, supply chain constraints/lead times, etc."

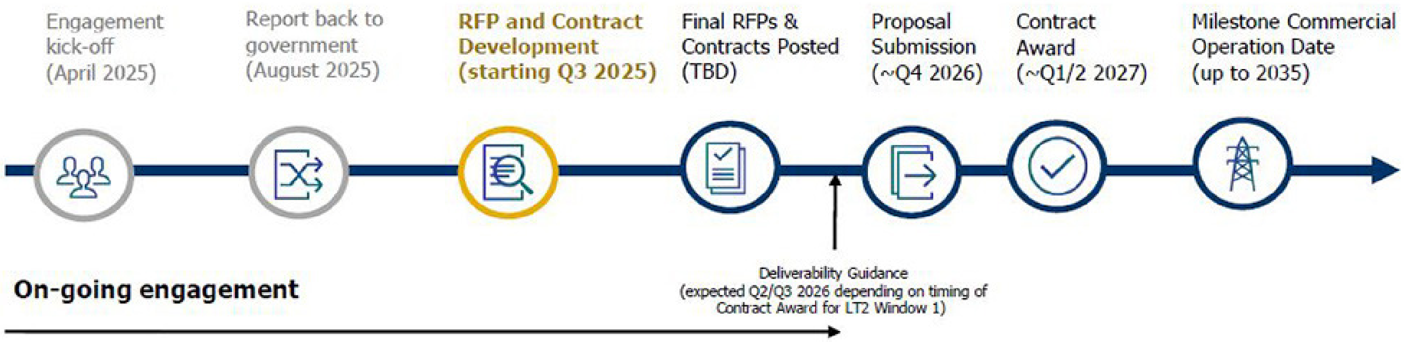
The proposed 100-MW maximum is included in— not in addition to — the total capacity stream target of 600 to 800 MW. It is not a set-aside, meaning only the most cost-effective proposals will be chosen.

D'Souza said the 50-MW minimum size for eligibility reflected "projects around that size that are currently working towards commercial operation."

"If … stakeholders think that projects less than that size should be considered, we're happy to hear it," she added. "But that threshold was … set based on our expectation of what is possible, and [to incentivize] projects of a commercial scale rather than a pilot scale."

Hydro Refurbishments Under Consideration

Although the LLT RFP is intended for new build resources, IESO continues to consider whether hydro redevelopments should be eligible to participate.



Timeline for IESO's long lead-time procurement | *IESO*

The ISO said stakeholders told it that replacement equipment no longer is available for hydro facilities built in the early 1900s and that long-term contracts would be needed to make hydro rebuilds economic.

Regulation-ready Resources

To help manage the increasing penetration of variable generation resources and industrial facilities with fluctuating loads, IESO also is considering requiring that LLT resources be equipped to provide regulation services.

"IESO is forecasting an increased need for regulation services in the future; both hydroelectric and LDES are ideal candidate technologies to provide regulation services," IESO said in a *presentation*.

IESO would require only that LLT resources be "regulation ready" — a minimum ramp rate of 5 MW/min and the ability to follow regulation signals every four seconds or less. Regulation services would be procured and paid for separately.

The requirement would apply to all capacity resources and hydro resources that can provide a 20-MW range (±10 MW regulation) above their minimum loading point.

Mid-term Outage

In response to feedback following its Sept. 16 engagement session, IESO said it would consider allowing resource owners a "mid-term extended outage" of up to 12 months after the 20th anniversary of the contract — up from the six-month outage initially proposed. (See *IESO Ups Capacity Target for Long Lead-Time Resources*.)

IESO said the mid-term extended outage would allow suppliers to complete "small-scale work that may be required to allow the facility to continue to operate and is not intended to be a period over which major refurbishment work is completed."

Must-offer Obligations

As in the LT2(c-1) contract, LLT suppliers will be required to offer their facility's output into the day-ahead market. But IESO proposes to expand the definition of "qualifying hours" for long lead-time resources to include weekends and holidays in addition to the 7 a.m. to 11 p.m. business day definition for the first LT2 capacity contract.

IESO also is considering a must-offer requirement for LLT capacity resources in the real-time market "to better align with operational needs."

"We have seen some periods of need outside of the hours that are included in the qualifying hours," D'Souza said. "Given that these are going to be 40-year contracts, we are looking to ensure that we're getting the most benefit and flexibility out of these resources."

IESO asked for feedback on how the expanded qualifying hours, and RT must-offer obligations, would affect the cost and operations of proposed projects.

Barreca said IESO is trying to address uncertainty about how system conditions will be in 40 years. "We recognize that none of these will likely be cost-free, and so we want to be able to — as always — take your feedback on these and make an informed decision as to whether the benefits that we may see from them would be worth the cost."

"Our intuition is that expanding qualifying hours would not be such a huge burden, although maybe there's some middle ground in there between what we have written on the slides here and what" suppliers want, he added. "The real-time offer is a bit more of an open question, in terms of both what the costs might be and what the benefits might be."

Contract Length

IESO rejected requests that it consider contracts longer than 40 years. Some stakeholders said the 40-year term didn't reflect compressed air and pumped storage mechanical components that have an expected life of more than 60 years.

Stakeholders also asked IESO to use an "open book process" regarding long-term debt for LDES that would allow price adjustments at the midpoint of their proposed 60-year contract term.

IESO said it is not considering a term longer than 40 years. "Proponents should consider expected costs (including those related to long term debt) over the contract term when establishing proposal prices," it said.

IESO asked stakeholders to submit written feedback to *engagement@ieso.ca* by Nov. 4. ■

Ontario Opens Talks on Repowering Old Generation

By Rich Heidorn Jr.

IESO is asking generation owners what it will take to extend the lives of their units beyond their current contracts as Ontario seeks to meet a projected 75% load increase by 2050.

IESO's expiring contracts will grow from 5,000 MW/year in 2029 to more than 20,000 MW/year in 2040.

The ISO said it plans to begin soliciting repowering facilities in the Long-Term 2 Window 2 procurement, scheduled for Q2 2026. It will be open to energy and capacity streams, with repowering projects seeking 20-year commitments likely competing against greenfield projects.

"We're very cognizant as the ISO that we're going to need a … majority of … these existing facilities to come back and to sign on for an additional term," IESO's Ben Weir said during an engagement session Oct. 20. "So we really want to work with everybody to make sure that the framework is tenable."

Dave Barreca, IESO's supervisor of resource acquisition, said the ISO's goal is to "secure the most cost-effective resources available [and] maximize the value of Ontario's existing generation fleet."

"As we all know, we forecast continued electricity growth over that period. And so there is a need for that power to come from somewhere, and I think that facilities that already exist — steel in the ground — is certainly as good a place as any."

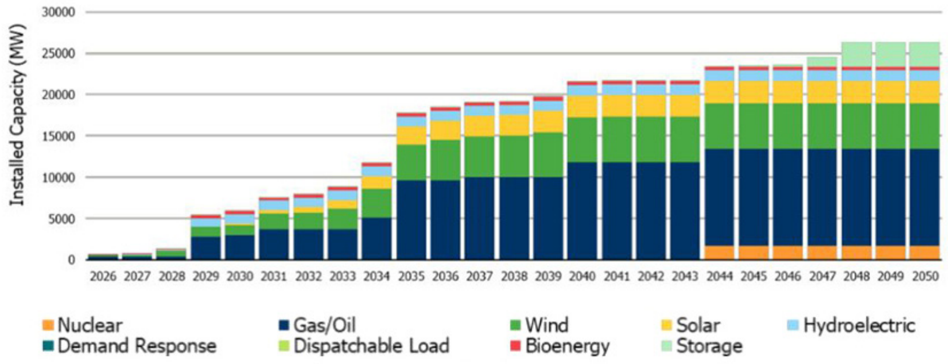
Current Practice

IESO has extended some expiring contracts by five years in the Medium-Term procurements (MT1, MT2) but it recognizes that some facilities will need longer contracts and big investments — including large-scale equipment replacements — to continue running.

"These facilities and others like them will continue to age," Barreca said. "And so the question then becomes … what to do — other than, of course, decommissioning. And as these facilities get older, the five-year term may become … less feasible to keep that facility running."

Why This Matters

Ontario won't be able to meet its growing electric demand without extending the lives of most generation currently under contract.



IESO's expiring contracts will grow from 5,000 MW/year in 2029 to more than 20,000 MW/year in 2040. | *IESO*

Definitions

IESO laid out an initial set of definitions for the program:

- repowering: full or partial replacement that results in a "like new" facility and may increase output;
- refurbishment: smaller-scale improvements that will extend lifespan for a shorter period and may result in increased output;
- upgrades: replacing components such as turbines with more efficient equipment to increase plant output; and
- expansions: adding new generating units to an existing facility to increase output.

But IESO also asked generators to help it fine-tune its definitions. "There is likely a range of viable options for existing facilities nearing the end of their current commitments," it said in a presentation. "IESO is seeking to better understand these options in order to appropriately design repowering rules."

Contract Term Risk

Barreca said IESO wants to balance certainty for owners with ratepayers' "contract term risk"— the risk of too many facilities winning repowering contracts — and taking outages — at the same time.

"We're going to see the retirement — or at least temporary retirement — of the Pickering Generating Station [for its own *repowering*]. So we can't really afford to let everyone go off and repower at the same time," Barreca said.

Gas Repowerings a Provincial Policy Matter

Weir said the ISO's repowering rules likely will include technology-specific conditions — including those that would apply to repowering of gas facilities. "At the end of the day, whether we are going to allow repowered gas facilities will be a government policy call," he said.

The Ministry of Energy and Mines' Integrated Energy Plan calls for "the rational expansion of the natural gas network," warning that "a premature phaseout of natural gas-fired electricity generation is not feasible and would hurt electricity consumers and the economy." (See *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

Next Steps

IESO requested that written feedback on the repowering concept be submitted to *engagement@ieso.ca* by Nov. 21. Among the issues on which it seeks input are required contract length, potential regulatory barriers, eligibility and contract design, and the likelihood of generation owners choosing to decommission rather than repower.

The ISO promised a follow-up engagement in early 2026. ■

IESO Considers How to Grow Ontario's Economy amid Deepening Trade War

By Michael Brooks

IESO is considering ways to grow Ontario's economy and secure its energy supply without relying on trade with its U.S. neighbors, just as President Donald Trump launched another salvo in his ongoing trade war on Canada.

Trump on Oct. 23 *posted* on Truth Social that he was ending all trade negotiations with Canada after learning that an advertisement sponsored by Ontario would be broadcast during Game 1 of the World Series the next day. The *somber ad* included images of Americans working while excerpts from a *1987 radio address* by President Ronald Reagan criticizing tariffs are heard.

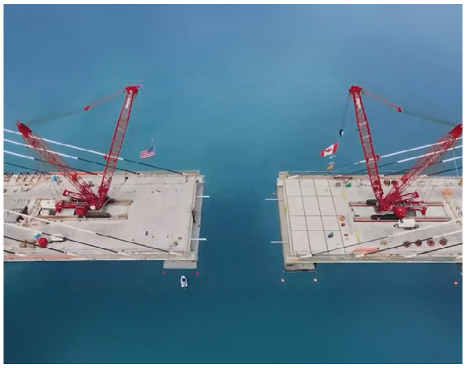
In a subsequent *post* Oct. 25 calling the ad "fraudulent" and a "hostile act," Trump announced he will increase the tariffs on Canada by an additional 10%.

Trump's posts came just after Prime Minister Mark Carney *announced* a goal for Canada to double its non-U.S. exports in the next decade, pointing to the president's ongoing tariffs. "We have to take care of ourselves because we can't rely on one foreign partner," Carney said.

The moves are just the latest in the nine months of "chaos" since the trade war began, as Lauren Tedesco, COO of the Automotive Parts Manufacturers' Association, described them during a *meeting* of the IESO Strategic Advisory Committee on Oct. 16.

Providing a customer perspective to a panel discussion on the role of electricity in economic growth, Tedesco spoke about "the amount of stability that we need across Ontario right now given what's happening right now in the south with our biggest trading partner."

"We have about $45 [billion] or $46 billion that have been invested in the last couple of years across the federal and provincial governments looking at what the future is for electric vehicles here in Canada," Tedesco said. "We have a lot of advanced manufacturing that takes place" in Ontario that consumes a "huge" amount of energy. "This will grow even further." That depends on "stability here at home … because of the nature of what's happening in the world, not just with our partners in the south. …



An image used by the government of Ontario in its anti-tariff advertisement broadcast in the U.S. | *Government of Ontario*

"Of course, looking at the instability that's happening across the U.S. right now, it's only been nine months, and we've seen a lot of chaos," she said. "I think the biggest role of the ISO is that, people do not understand how important the stability and reliability of energy is in the province because they are so used to it. … People often take things for granted. So I think part of that economic growth is also the awareness of the role of the ISO."

"One of the key strategic issues for the IESO is to broaden its lens to incorporate both economic growth and innovation," moderator Monica Gattinger, a professor of political studies at the University of Ottawa and chair of the college's *Positive Energy* program, said in introducing the panel. "This is new for the organization." Economic growth "can be quite lumpy in its dynamics and, in the current moment, can also be very uncertain. …

"The IESO plays a pivotal role in terms of economic growth and innovation by fostering integration and alignment across a number of key areas of the energy system," including between transmission and distribution, and the gas and electricity sectors, Gattinger said.

Much of the discussion focused on how to attract foreign investment to the province — without relying on the U.S.

"The reality is, our ability to grow Ontario's economy is going to found itself in our ability to make sure we can attract investment into the province," said Heidi Bredenholler-Prasad, vice president of commercial, strategy and business development at Enbridge Gas. "And it really does depend on ensuring that we do have a stable, future-looking energy system."

Bredenholler-Prasad emphasized "removing red tape and reducing friction for businesses to want to do business in Ontario."

"The reality is there's a misalignment right now with respect to the regulatory environment as well as government policy," she said. "And those two really need to sync up at the pace with which customers need to move."

IESO can help by providing "well-informed scenario modeling" and set an "example of what good coordinated and integrated planning might look like," she said. It also can have a role in "advancing coordination between gas distributors, municipalities, as well as the" Ontario Energy Board. "This coordinated planning needs to be streamlined."

Tedesco urged IESO, and the province, to focus on the benefits they can provide.

"I travel back and forth to D.C. a fair bit, and when we are having these meetings at places like the Department of Commerce … we can stand there with all of our facts and our data to say, 'This is why Canada is important; this is why automotive is important; this is why you should pay attention and your tariffs are not helpful to us' — that does not resonate," Tedesco said. "Could I be so bold as to say they don't care? They have so many things happening internally, and there's so much upheaval that is taking place, and their goal is to protect the U.S. …

"When we're looking to attract investment, it has to be with the eye of not, 'here's what Ontario has to offer,' but with 'here's how we can help you.'"

She also praised the country's new Major Projects Office as important to increasing province-to-province coordination. (See "Major Projects Office," *Ontario Environmentalists Slam New Nuclear Units*.) ■

ISO-NE Discusses Resource Deliverability Under CAR

By Jon Lamson

ISO-NE presented a high-level overview of how it plans to account for resource deliverability in its updated capacity accreditation framework at the NEPOOL Reliability Committee meeting Oct. 22.

Resource deliverability calculations are intended to reflect system constraints that limit a resource's output during key periods.

"Final capacity accreditation values must consider resource megawatts and the capability of the transmission system to deliver megawatts from resources to the load," said Alex Rost, director of transmission services at ISO-NE.

He noted that the Capacity Auction Reform (CAR) project will not change the process of determining deliverability through the interconnection process.

However, the new accreditation process will need to update how it accounts for deliverability, which will be used as a model input instead of an "*expost* adjustment," Rost said.

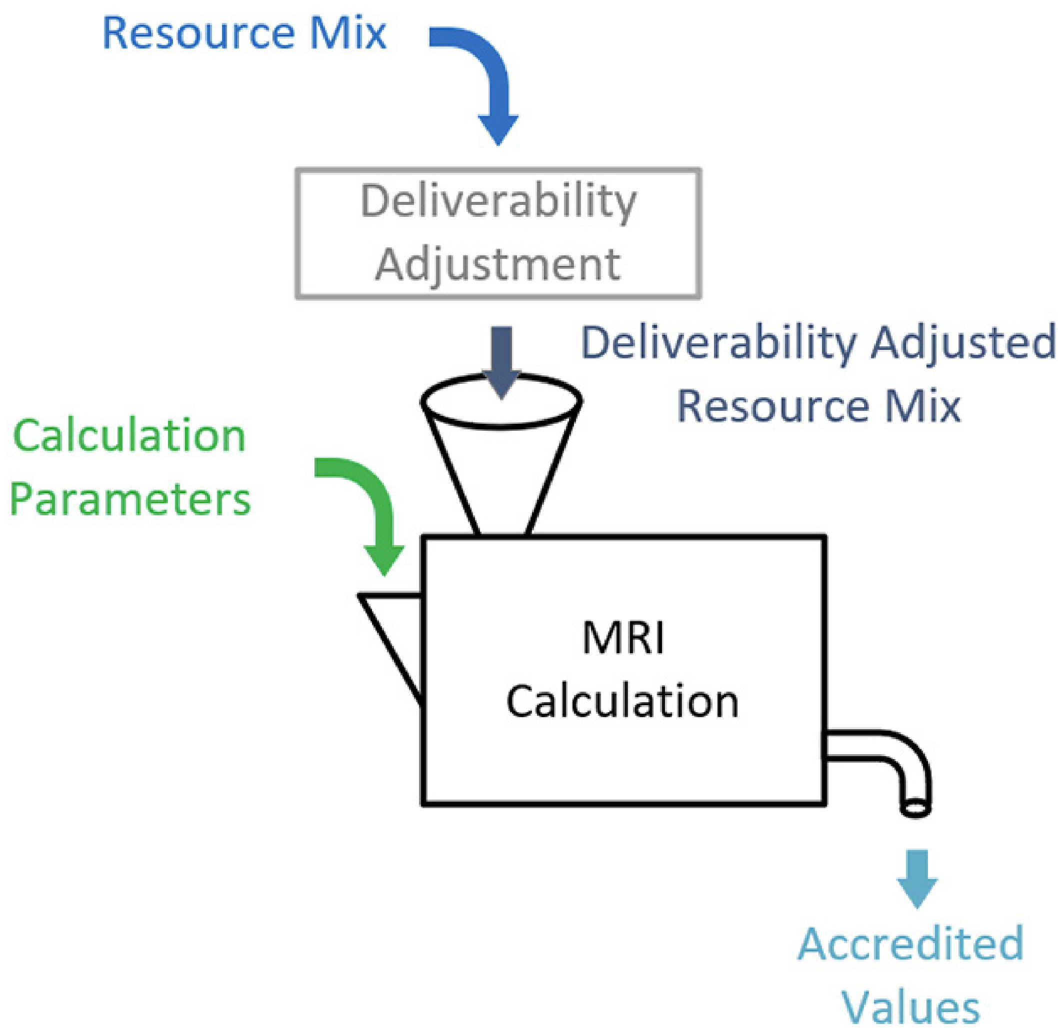
"The ISO proposes to account for resource deliverability in accreditation calculations through an ex-ante adjustment to the size of a resource to be modeled in the RAA [resource adequacy assessment]," said Marianne Perben, director of planning services at ISO-NE.

ISO-NE proposes to rely on a scaling factor to account for deliverability limits, which would equal the lower value of either 1.0 or the ratio of deliverability value to "dependable capability," Perben said.

Dependable capability "is an audit-based value reflecting a resource's expected energy contribution under high load conditions," Perben said. "The greater a resource's deliverability value is above its DCap value, the more likely it will be able to provide its capacity to the system without transmission limitations."

Each resource's DCap value will be calculated based on its median performance during peak hours, which ISO-NE plans to define as the top 500 load hours from the relevant season from the prior year.

The value will be calculated for all resources except "demand capacity resources participating with energy efficiency measures," said Jennifer Engelson, supervisor of resource qualification at ISO-NE. She added that energy efficiency resources "report a single seasonal performance estimate and therefore, hourly performance values are not available." ■



ISO-NE's proposed approach to account for resource deliverability in accreditation calculations | *ISO-NE*

ISO-NE Gives Update on Asset Condition Reviewer Role

By Jon Lamson

ISO-NE has identified nine projects to include in an interim asset condition review process starting in October, which will proceed as the RTO works to stand up internal condition review capabilities by the start of 2027.

The asset condition reviewer is "envisioned to provide an independent review and opinion of asset condition projects submitted for review by the TOs [transmission owners]," Al McBride, ISO-NE vice president of system planning, *told* the ISO-NE Planning Advisory Committee (PAC) on Oct. 23.

ISO-NE agreed to take on the role following pressure from states and consumer advocates, who have expressed concern about a lack of oversight and transparency on spending by transmission owners to upgrade existing assets. Asset condition spending has increased significantly in recent years, which transmission owners say is due to escalating costs associated with maintaining aging grid infrastructure. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

The RTO has emphasized that it will not take on a regulatory role or comment on the prudence of investments; asset condition spending is under FERC jurisdiction and is processed through formula rate procedures.

The new role, McBride said, "would inform states, stakeholders and PAC attendees" with "holistic information and much more insight on these projects."

While ISO-NE will not comment on "the question of whether the costs of any given asset condition project are prudent," it plans to offer opinions on whether transmission owners have adequately demonstrated project needs, and whether they adequately evaluated alternatives.

ISO-NE is seeking feedback on the proposal by Nov. 21 on the objectives of the role, governance structures, criteria for project review, stakeholder involvement and how reviews would fit in with transmission planning processes.

Asked whether ISO-NE plans to employ a cost threshold for reviewing projects, McBride said, "at this point, we expect that there would be a threshold, but that has not been decided, and we're open to feedback."

Why This Matters

Asset condition costs make up the bulk of transmission spending in New England.

Several stakeholders said they are eager to get into discussions about how the new role could inform efforts to right-size transmission projects.

"Those discussions will come, but they will come in the right order, which we think is after we've had some time to establish the asset condition reviewer itself," McBride said.

ISO-NE plans to rely on consultants to evaluate projects prior to the official rollout of the new asset condition reviewer role. It has selected nine proposed projects to review during this interim period:

- Eversource's rebuild of Line 1670/1771 in Connecticut, estimated to cost more than $120 million.
- Eversource's rebuilds in the West Medway/West Walpole Corridor in Massachusetts, estimated to cost more than $75 million.
- Eversource's underground cable modernization plan in the Boston area, a multiphase project the New England States Committee on Electricity has *estimated* will cost in the range of $8 billion to $9 billion.
- Avangrid's cable replacements on a line in southern Connecticut, estimated to cost more than $100 million.
- Rhode Island Energy's rebuild of Line 332, estimated to cost more than $75 million.
- National Grid's rebuild of Line 323 in eastern Massachusetts, estimated to cost more than $75 million.
- National Grid's partial rebuild of Line 394/397 in northeastern Massachusetts, estimated to cost more than $100 million.
- VELCO's partial rebuild of Line F206 in Vermont and New Hampshire, estimated to cost more than $50 million.
- VELCO's Highgate converter replacement, estimated to cost more than $500 million.

"The ISO is targeting a three-month review period for each project, except for the underground cable modernization plan," McBride said. "These interim projects would be reviewed between early November 2025 and the end of 2026, as the TOs bring those selected projects forward to present and discuss at the PAC."

ISO-NE has asked for comments on the interim project list by Nov. 7.

Asset Condition Project Presentations

Also at the PAC meeting, several representatives of transmission owners discussed asset condition project proposals.

From Eversource, Chris Soderman presented a $143 million project to fully rebuild a 115-kV line in central Connecticut. He said a full rebuild, instead of targeted structure replacements, would address the immediate needs along with "future asset condition needs by replacing structures that are deteriorating and likely to require replacement in the near future."

The project is included in the interim review list presented by ISO-NE at the meeting.

Soderman said the project is needed to address "multiple structure concerns including foundation damage, structure deterioration and rust."

Of the 83 structures on the affected lines, Eversource estimated about half require planned replacement or emergency replacement. He said the condition of the other structures warrants consideration of replacement "in conjunction with other structure replacements."

Soderman added that, without a full rebuild, the company likely would have to return to the PAC with a follow-up project "within two or three years" to replace the remaining structures.

Eversource plans to bring the proposal for a follow-up presentation at the PAC in the second quarter of 2026, with construction scheduled to begin in early

2027.

Multiple PAC members expressed concern about the high per-mile costs of the project, and Sheila Keane of the New England States Committee on Electricity (NESCOE) asked for more granular information on cost drivers for the project.

Rafael Panos of National Grid presented a cost update on a transformer replacement project in Bridgewater, Mass. The project includes replacing a transformer, refurbishing a transformer, replacing multiple circuit breakers and upgrading associated equipment. The project cost has increased from the 2022 estimate of about $26 million to nearly $38 million. The higher cost estimate is driven by inflation, escalation and a longer construction duration, Panos said.

Fabio Dallorto, lead engineer for transmission planning at ISO-NE, presented an update to the asset condition database.

He said transmission owners have added 21 new projects totaling $228 million since the last update in June. (See *New England Transmission Owners Add $95M to Asset Condition List*.) He added that 12 projects totaling $443 million have been placed in service since the last update.

Copperweld Shield Wire Replacements

Dave Burnham of Eversource discussed the company's strategy for replacing Copperweld shield wire in its service territory. He said the company has found Copperweld shield wire to have a failure rate about six times higher than other types of shield wire.

"Copperweld shield wire was once an industry standard but has been prone to failure, and it is increasingly difficult to obtain replacement equipment," he said.

"Since 2018, Eversource's primary strategy to address Copperweld shield wire concerns has been to replace Copperweld shield wire in conjunction with projects that also address other asset condition needs," Burnham said. "Eversource estimates that most Copperweld shield wire will be removed by 2030."

Eversource's practice is to replace copper wire with Alumoweld and optical ground wire (OPGW).

"In most cases, OPGW is preferrable to Alumoweld because it has similar costs and provides additional telecommunications capabilities," Burnham said.

He noted that Eversource mistakenly presented incorrect data on Copperweld shield wire in 11 asset condition presentations to the PAC between 2021 and 2023.

"These presentations incorrectly provided results from testing of copper conductor and [extra-high strength] steel shield wire performed in 2018," Burnham said. "Test results from Copperweld shield wire performed in 2022 showed failure of tensile elongation test, not rated breaking strength test, corrosion or signs of overheating."

Keane of NESCOE said it is "concerning that we were presented incorrect evidence to support a certain approach," and expressed her hope "that this is the type of thing that an asset condition reviewer will be looking at." ■

Line 1670/1771
Structure 4133
Foundation Damage

Line 1670/1771
Structure 2596
Top cross member bent

Deteriorating structures on Eversource's 1670 & 1771 lines | *Eversource*

Pipeline Expansion Highlights Key Questions About Gas in New England

By Jon Lamson

Aerial view of the Mystic Generating Station in Everett, Mass. | *InvictaHOG, Public Domain, via Wikimedia Commons*

A relatively small project aiming to increase gas pipeline capacity into New England is raising larger underlying questions about how the region will balance gas reliability and affordability with longer-term efforts to transition away from natural gas.

Enbridge's proposed expansion of its Algonquin pipeline, *announced* in September, has an estimated cost of $300 million and would increase the pipeline's capacity into the region by about 2.5%. The company aims to complete the project in 2029.

Algonquin has announced it has reached agreements with seven utilities for the added capacity, including Rhode Island Energy and subsidiaries of Eversource Energy, which submitted a pair of 10-year supply delivery contracts associated with the project to the Massachusetts Department of Public Utilities in September.

Eversource said the contracts are needed to "address a reliability risk related to operational changes" instituted by Algonquin in 2019 reducing flexibility in nominations that previously allowed the company to nominate more than their contracted delivery entitlements in certain areas during cold-weather periods.

The company also said the added capacity would eliminate its "need to extend the G-Lateral supply portion" of its contracts with the Everett Marine Terminal (EMT), a major LNG import facility located north of Boston and owned by Constellation Energy.

By replacing LNG supply with pipeline gas, the project would reduce total gas costs for customers of two subsidiaries by about 5% and 1%, the company said.

"Without the proposed agreement, [Eversource] and its customers risk exposure to inadequate and unreliable supply and high city-gate pricing during peak days for customers served by Algonquin's G-System, and would need [to] enter into negotiations with Constellation … for gas supplies to serve the G-Lateral from EMT after 2030," Eversource argued.

However, environmental nonprofits argue that the Algonquin expansion project would not eliminate the region's overall need for the Everett terminal and would instead likely shift its costs to other customers.

In Eversource's filing, the company appears to acknowledge that the Algonquin expansion would not eliminate the region's reliance on Everett, writing that the agreement would "not resolve regional dependence on natural gas from peaking resources" and adding that the terminal "provides a unique and critical energy resource in New England."

In joint comments submitted earlier in October, the Acadia Center and the Conservation Law Foundation (CLF) wrote that the DPU must consider how the contracts "will impact not only Eversource customers, but also other gas customers, including National Grid and Unitil, whose contracts with Constellation mirror [Eversource's]."

The Role of Everett

Until spring 2024, Everett's main customer was Mystic Generating Station, a 1,413-MW, Constellation-owned combined cycle plant located nearby.

In the months leading up to Mystic's

Why This Matters

As the pipeline industry struggles with many of the same obstacles that have prevented development in New England over the past decade, the fate of gas expansion projects and the Everett LNG import facility could have significant ramifications for the region's generation fleet and decarbonization efforts.

retirement, local distribution companies owned by National Grid, Eversource and Unitil reached agreements with Constellation to keep Everett open through 2030. The contracts were necessary to provide adequate supply and preserve system reliability, the utilities wrote (DPU 24-25-B, *et al.*). (See *Massachusetts DPU Approves Everett LNG Contracts*.)

Everett "is ideally located in the heart of the market" at the back end of the Tennessee and Algonquin pipelines, Richard Levitan, president of the energy consulting firm Levitan & Associates, explained in an interview with *RTO Insider*.

Levitan stressed the importance of local deliverability to the system. LNG from Everett and Repsol's Saint John LNG terminal in New Brunswick provides the "oomph to energize the network of pipelines serving gas utilities and generators in New England during cold snaps or some type of outage contingency along the mainlines serving New England," he said.

He added that Everett "is the primary hub of truck-transported LNG to refill the dozens of satellite LNG tanks in New England that bolster pressure behind the pipeline citygates," a role that cannot be replicated by the Saint John terminal.

Levitan noted that the Algonquin expansion project "is small in relation to the daily output" of both the Everett and Saint John facilities when the terminals are performing. He emphasized that, unlike conventional forward-haul service from the Gulf Coast or Marcellus Shale, LNG facilities provide operational and scheduling flexibility by enabling injections into the back end of the gas systems.

"When these import facilities are dispatching during cold weather events, it's beneficial to the bulk electric generation market, and also to the LDCs, who generally look to supplement their pressures via displacement services when there are harsh operating conditions," he said.

While utilities and gas generators rely on Everett to add supply downstream of New England's gas constraint during peak periods and to provide backup supply during pipeline outages, the facility again faces an uncertain future after its contracts with the utilities expire in 2030.

The contracts are costly for ratepayers; Eversource estimated in 2024 that they would increase rates by 5 to 7% for customers of one subsidiary and 2 to 3% for customers of another. Long-term reliance on Everett would also likely run contrary to Massachusetts' longer-term efforts to transition away from natural gas to reach net-zero emissions by 2050.

When approving the contracts, the DPU required the gas companies to "make significant strides to reduce or eliminate their reliance on EMT in the near-term" and directed them to "fully investigate all possible alternatives to EMT … including energy efficiency, strategic electrification and networked geothermal projects and, to the extent feasible, to coordinate their planning efforts."

The order also required annual reports about the utilities' efforts to reduce reliance on the facility, and in fall 2024, the Massachusetts Office of Energy Transformation established a working group focused on transitioning away from Everett.

Who Pays?

While the pace and trajectory of the gas transition in Massachusetts likely will determine the long-term demand for existing and new gas infrastructure, the fate of Everett, as well as the fate of gas pipeline expansion projects into the region, may be defined in large part by questions about funding.

The Algonquin expansion project essentially is a significantly scaled back version of Enbridge's previously introduced "Project Maple," which proposed to increase Algonquin's capacity by up to 250,000 Dth/d at the eastern end of the pipeline. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

The smaller size of the updated 75,000 Dth/d expansion project appears to reflect the challenges of finding long-term customers for the increased capacity.

"Following the conclusion of the Project Maple open season in November of 2023, we decided to right-size Project Maple to better meet our customers' specific needs, with a smart, targeted enhancement," Enbridge spokesperson Melissa Sherburne said in a statement.

While New England heavily relies on gas generation, which hit a record high in 2024, generators' access to gas is constrained during cold weather when heating demand is high. (See *New England Gas Generation Hit a Record High in 2024*.) Generators have historically been reluctant to take on long-term gas contracts, largely because of the financial risks associated with assuming these commitments.

Electric ratepayers also appear unlikely to finance new infrastructure; a 2016 ruling by the Massachusetts Supreme Judicial Court prohibits charging electric customers for the costs of new pipelines.

Meanwhile, residential, commercial and industrial gas demand has been relatively stagnant in recent years, and, seeking to decarbonize, Massachusetts lawmakers and regulators have taken significant steps to slow the expansion of the system and push gas customers to electrify. (See *Outgoing Mass. DPU Chair Van Nostrand Discusses Gas Transition*.)

"As far as who would pay [for Everett] in 2030 if Eversource is not a contracted party, it would have to be other LDCs, conceivably generators if we see the evolution of price signals under accreditation taking form, and marketers," Levitan said.

As ISO-NE overhauls how it accredits resources in the capacity market, the RTO is poised to increase incentives for resources to procure firm fuel. However, the extent to which this will cause generators to enter long-term firm contracts is unclear.

In ISO-NE's Capacity Auction Reform project to date, "we're not seeing the evolution of accreditation principles that will clearly induce the generators to line up firm rights, so I don't think at this moment in time we can reasonably expect the generators as a cohort group in New England to foot the bill for a major new pipeline push," Levitan said.

Everett's funding challenges mirror the challenges faced by any large pipeline project into the region, which are only complicated by the state's push to decarbonize.

Climate and consumer advocates have argued that Massachusetts must be careful not to make long-term investments in the gas system that end up becoming stranded assets. Some advocates see the 10-year duration of Eversource's proposed Algonquin expansion contracts as reflecting uncertainty about long-term gas demand on the distribution system.

Joe LaRusso, senior advocate at the Acadia Center, said he is skeptical that gas utilities will experience enough new demand to support a "a substantial increase in gas capacity into the region."

He added that pipeline companies looking to build major new projects "can't find the off-takers for this stuff; they can't get it built."

Acadia and CLF's comments on Eversource's contracts with Enbridge focus on Eversource's underlying assumptions about its forecasted gas demand between 2029 and 2039. The groups highlight data from the U.S. Energy Information Administration indicating that overall residential, commercial and industrial gas demand in Massachusetts declined between 2019 and 2024.

They wrote that Eversource has provided "no basis to determine what their gas requirement will be over the term of the proposed contracts," nor data on how "declines in statewide gas consumption in those sectors might ultimately influence either their overall consumption or their design day supply."

In Eversource's initial petition, the company wrote it "has not identified other viable alternatives to the proposed agreement," adding that "the pace, scale and scope of energy efficiency and electrification would be insufficient to address the load requirements for the G-Lateral."

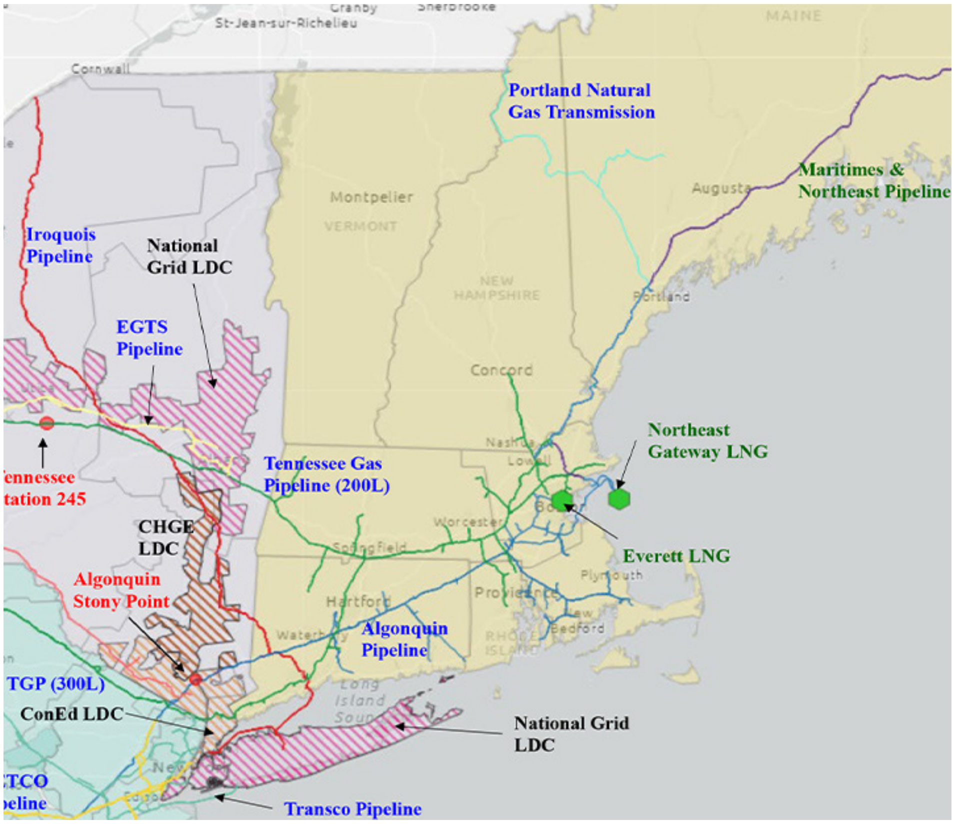
Decarbonization Challenges

As utilities and regulators work to ensure the reliability of the state's gas system, an inherent tension exists between investments to bolster the system and efforts to decarbonize.

While the gas industry frequently points to the reduction in carbon dioxide emissions associated with burning natural gas instead of coal or oil, methane is a key driver of manmade climate change and has particularly severe warming effects when evaluated over a more immediate time frame.

In a landmark order in late 2023, the DPU ruled that the decarbonization of the state's gas system should center around electrification and emphasized the need for a managed transition away from gas and gas infrastructure (DPU 20-80-B). (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

The state remains in the early stages



Interstate pipelines serving eastern New York (2022) | *S&P Global*

of implementing this new regulatory framework, and in recent months, utilities and climate advocates have clashed over the LDCs' legal obligation to serve customers, and whether the utilities could require customers to give up their gas service when decommissioning a section of pipe.

If successful, the electrification push would drive a substantial increase in power demand, which could cause continued growth or reliance on gas generation. While there is almost no proposed new gas generation in the ISO-NE queue, the challenges experienced in the offshore wind industry create significant questions about how the region will meet this growing demand.

"The demise, temporary or not, of offshore wind bodes poorly for certain environmental goals to be achieved in the early and mid-2030s if electrification gets the kind of traction that regional policymakers envision," Levitan said. "There could be much more work burden on the existing thermal fleet to accommodate a pathway that is all about switching over from a summer to winter peak because of electrification."

But for grassroots climate activists in Massachusetts, any efforts to expand natural gas infrastructure into the state are a step in the wrong direction.

"The answer is not, and never has been, keeping on with the gas system," said Cathy Kristofferson, a longtime environmental activist in the state who co-founded the Massachusetts Pipe Line Awareness Network. "Everyone's trying to figure out the affordability angle of it all, and for us, adding a bunch more steel in the ground is never affordable."

Rosemary Wessel, an activist with the Berkshire Environmental Action Team, said Enbridge's recent Algonquin proposal appears to be part of a strategy focused on incremental expansions to increase gas capacity into the region.

At an industry conference in September, Mike Dirrane, director of Northeast marketing at Enbridge, speculated that there may be an additional project after the current Algonquin expansion effort "to meet additional needs further down the road." (See *Gas Industry Sees Political Opportunity in New England*.)

"They're segmenting a larger expansion into small projects," Wessel said. "We should not be serving that by approving contracts for more gas." ■

Storage Projects Dominate ISO-NE Transitional Cluster Study

By Jon Lamson

ISO-NE's first interconnection cluster study held under new rules is made up mostly of large battery resources and contains only five wind and solar projects.

The transitional cluster study, which ISO-NE initiated in early October, includes 26 interconnection requests, with a net total of 7,205 MW. The requests include 21 battery storage projects, two solar projects, two offshore wind projects and one onshore wind project.

FERC Order 2023 required RTOs to transition from serial, first-come first-served interconnection processes, to first-ready first-served cluster study processes. The reforms are intended to reduce queue backlogs by disincentivizing speculative interconnection requests and sharing infrastructure upgrade costs among interconnection customers.

The transitional study marks the first cluster study under the new rules and is set to conclude in August 2026.

Alex Lawton, director at Advanced Energy United, said he expects the Order 2023 interconnection changes to "raise the bar for interconnection requests" and "increase the likelihood of projects actually being constructed."

Looking at the projects included in the first cluster study, he said he was "a little bit surprised to see so few solar projects but not surprised to see so much storage."

Why This Matters

Despite ISO-NE's projections for accelerating load growth through the end of the decade, the transitional cluster study includes a limited amount of new generation that could provide new supply to the region.

"We absolutely need a lot more storage, but we also need other low-cost clean

| *Convergent Energy and Power*

generation resources too, to bring new supply to meet growing demand," he said.

The storage requests in the cluster study total 5,632 MW, ranging in size from about 19 to 706 MW, with a median size of 214 MW.

The cluster includes a 1,200-MW interconnection request from SouthCoast Wind; a capacity-only request from Avangrid's New England Wind 1 project (previously called Park City Wind); and an 18-MW land-based wind project in Maine.

For solar, the cluster includes a 102-MW project in New Hampshire and a 253-MW project in Maine.

In its announcement of the study, ISO-NE noted that "more than 50 other requests with previously completed studies, most of which have signed interconnection agreements, remain in the queue and can continue working toward completing the interconnection process."

Francis Pullaro, president of RENEW Northeast, said the large number of storage projects in the cluster study likely is a result of procurement opportunities for large-scale storage projects in the region.

Massachusetts has an ongoing procurement for up to 1,500 MW of storage. The state received 13 bids from eight companies in September and is scheduled to select winning bids in December. (See *Massachusetts Seeks 1,500 MW of Mid-duration Energy Storage*.)

Maine has been working toward a 200-MW storage *procurement*, and Connecticut is in the process of selecting projects for a *procurement* open to solar, onshore wind and co-located storage. Meanwhile, state incentive programs generally are focused on small-scale projects.

"Frankly, there's not a lot of procurement opportunity for transmission-level solar," Pullaro said.

He added that it is "very challenging to find sites for large projects where you can get through siting and manage public acceptance," and that, to site large-scale solar projects, "you're usually talking about farmlands or having to clear cut forests."

The relatively small number of non-storage projects in the cluster, coupled with the significant number of withdrawals that have occurred over the past year, appears to be a major challenge for state clean energy goals, said Aidan Foley, founder of Glenvale Solar.

According to ISO-NE data, 22,480 MW of FERC-jurisdictional battery and clean energy projects have withdrawn from the RTO's interconnection queue this year. This includes about 10 GW of batteries, 11 GW of wind and 1.3 GW of solar.

"The sheer supply of projects, other than offshore wind, is terrible," Foley said. "The region is just totally screwed in terms of meeting its clean energy goals, and the next five years is going to be an absolute dead zone."

He said cost and new technical requirements posed barriers for projects seeking to enter the transitional cluster study. Because the ISO-NE queue has been closed since June 2024, newer projects without queue positions were not able to join the study, he added.

"The cost is really a humongous amount to anybody trying to weigh the investment needs of their portfolio," Foley said. He estimated the study process would require a roughly $6 million investment for generators larger than 20 MW seeking to participate in the transitional cluster.

Foley has argued that the study costs — including a $5 million commercial readiness deposit — are disproportionately burdensome for smaller resources that fall under ISO-NE's Large Generator Interconnection Procedures (LGIPs).

Notably, the cluster study contains only three projects smaller than 100 MW. All three of these requests are less than 20 MW, which is the size threshold that determines whether resources are subject to ISO-NE's LGIPs or Small Generator Interconnection Procedures (SGIPs).

Generators seeking to interconnect under the SGIPs were required to submit a $1 million commercial readiness deposit in the transitional cluster, compared to the $5 million deposit required from LGIP resources.

In the stakeholder process leading up to ISO-NE's Order 2023 compliance proposal, several stakeholders pushed for lower commercial readiness deposits, and Foley advocated for scaling deposit requirements to resource size. (See *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance*.) ■

September Energy Prices up in MISO

By Amanda Durish Cook

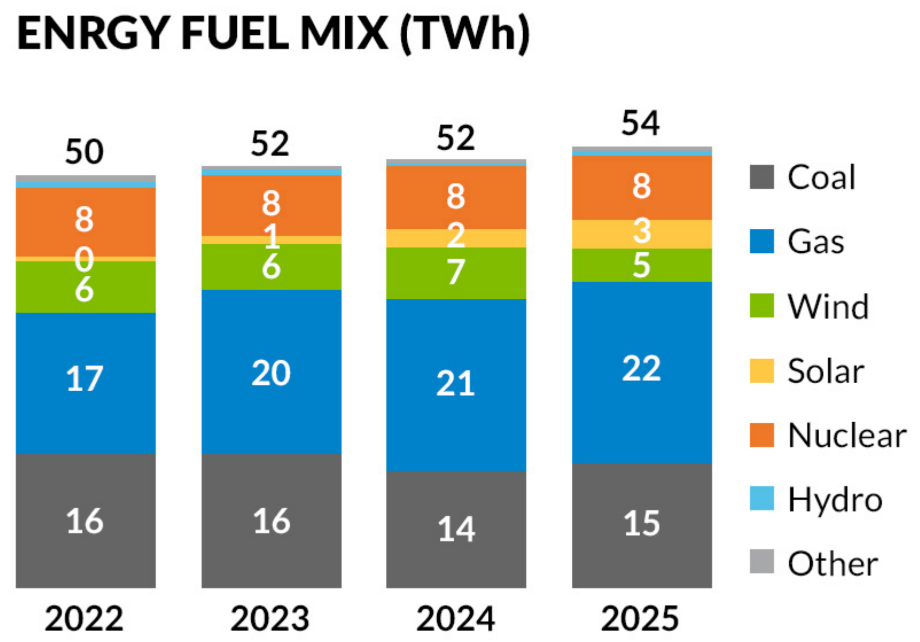
Year-over-year prices rose in MISO to serve a typical September peak.

MISO members *served* an average 76.3 GW daily load over September, with a 106-GW peak occurring Sept. 16. The month's peak demand wasn't unusual, less than a gigawatt from the 105.5-GW peak in September 2024 and smaller than September 2023's 114.6-GW peak. Average daily load was up slightly when compared to the approximate 75-GW average in September 2024.

Real-time prices, however, rose almost 1.5 times from September 2024, at $41/MWh versus $28/MWh. Average natural gas prices climbed from $2/MMBtu in September 2024 to $3/MMBtu September 2025. Coal stayed flat at about $2/MMBtu year over year.

MISO's solar peak was 14.5 GW while wind registered a 20.7 GW peak. Both occurred in early September.

Over the month, MISO experienced 47 GW in average daily generation outages, 9 GW higher than last September.



September 2025 energy fuel mix compared to previous Septembers | *MISO*

MISO declared a capacity advisory for the entire footprint Sept. 29 because of forced generation outages and limited transfer availability. It also called conservative operations on Sept. 28 due to unseasonably warm temperatures, generation outages and lower-than-normal renewable energy forecasts. ■

30+ Projects Under Consideration in MISO-SPP Joint Tx Effort

By Amanda Durish Cook

MISO and SPP said they will study more than 30 project suggestions — some estimated to cost more than $1 billion — in a four-state area in their pursuit of major, regionally cost-shared transmission projects.

The grid operators said they received 46 stakeholder-originated ideas for projects along their seam in Arkansas, Louisiana, Oklahoma and Texas. The two RTOs have culled the projects to 32 *proposals* and said they will test their potential and may build business cases for some under their coordinated system plan. (See *MISO, SPP Still on Hunt for Joint Transmission Under CSP*.) MISO and SPP ruled out most of the eliminated projects for focusing on local — not interregional — issues.

The 32 project contenders are concentrated along:

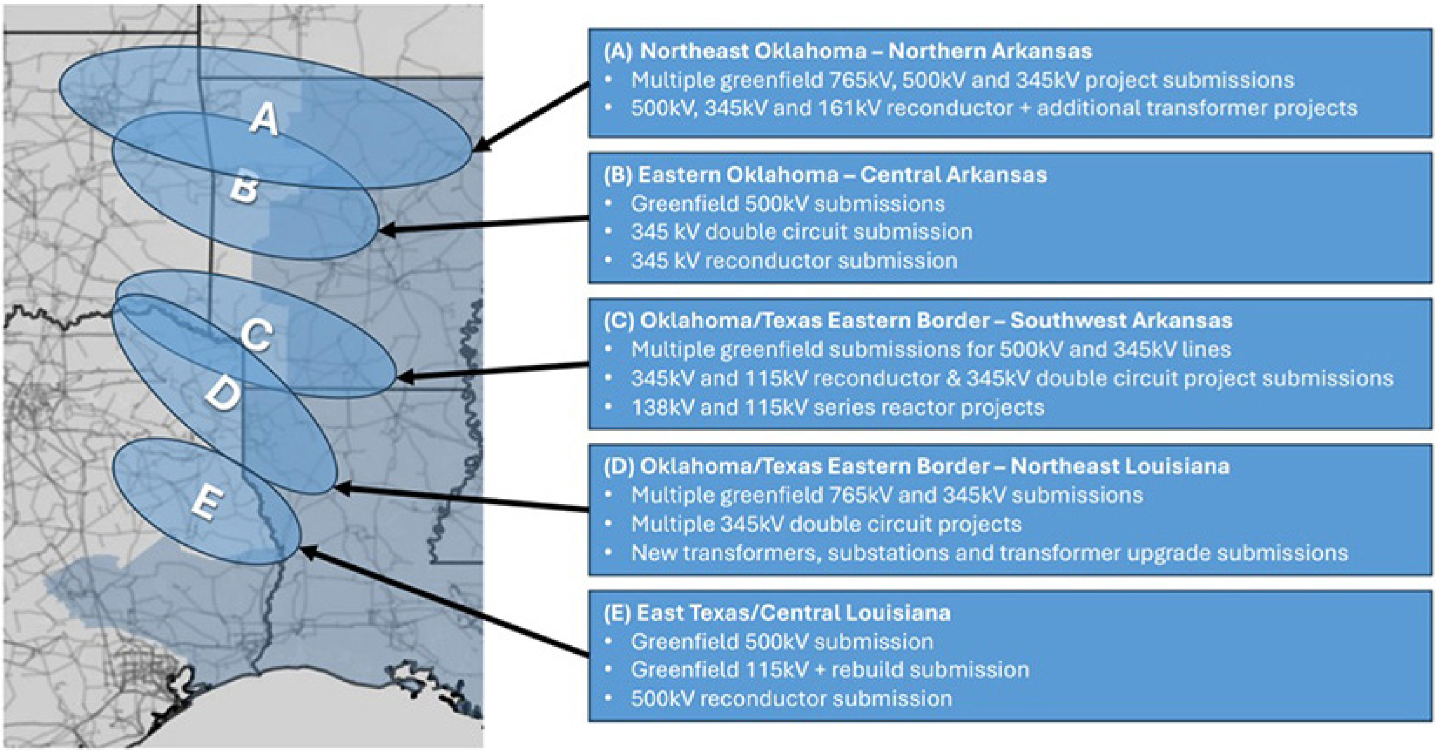
- Northeastern Oklahoma to northern Arkansas, where stakeholders submitted multiple greenfield 765-, 500- and 345-kV project ideas alongside reconductoring and additional transformer suggestions.
- Eastern Oklahoma to central Arkansas, which drew 500- and 345-kV line ideas.
- The Oklahoma-Texas eastern border to northeastern Louisiana garnered 765- and 345-kV proposals with ideas for new transformers, substations and transformer upgrade submissions.
- The Oklahoma-Texas eastern border to southwestern Arkansas, which could host new 500- and 345-kV lines and reconductoring, electrical reactor and double-circuit work.
- Eastern Texas to central Louisiana, where stakeholders recommended 500-kV work.

What's Next

By mid-December, MISO and SPP could have a draft portfolio of interregional projects along their seam in Arkansas, Louisiana, Oklahoma and Texas.

Ashleigh Moore, of MISO's interregional planning division, said MISO and SPP will analyze the candidates' performance in terms of adjusted production cost savings, mitigation of reliability issues and transfer capability improvements.

At the Oct. 24 MISO-SPP Interregional Planning Stakeholder Advisory Committee (IPSAC), MISO and SPP said they would have draft recommendations ready to share by the Dec. 12 IPSAC meeting. Staff said they will have more data, maps, and benefit estimates and adjusted production cost savings estimates then.



Areas of focus in MISO and SPP's interregional study with potential project ideas | *MISO and SPP*

The projects' price estimates range from $54 million to nearly $4 billion for one HVDC idea in northeastern Oklahoma and northern Arkansas. Eight projects on the list are estimated to cost more than $1 billion.

Moore said MISO and SPP are encouraged by the "valuable project ideas" from their stakeholders and that they were glad to see some of the projects zeroing in on key reliability paths between the RTOs. She said MISO and SPP will narrow the 32 "good ideas" to "high-performing, feasible and cost-effective" projects.

MISO's Jon George said the projects may culminate in a portfolio of interregional projects, with benefit-to-cost ratios calculated among a group of projects rather than individually.

The RTOs still are working on their 15-year modeling to build studies on and said it would be complete in November.

MISO and SPP said they may use the *seven* transmission benefits established in FERC Order 1920 to develop business cases for projects. If the two find beneficial projects, or a portfolio of projects, they would need to propose an interregional cost allocation plan for FERC approval. The two RTOs said cost sharing could be tackled in late 2026.

Southern Renewable Energy Association Executive Director Simon Mahan said while MISO and SPP's coordinated system plan studies in the past have been disappointing, this fresh list of project candidates seems promising.

"I think this is going to be getting us closer," Mahan said. He said some of the projects appear to be able to help outages that occurred earlier in 2025 in the Shreveport, La., area and previous voltage problems in northwestern Arkansas and southwestern Missouri during Winter Storm Elliot in late 2022.

MISO and SPP have never recommended a major, interregional cost-shared transmission project through their coordinated system plan study, despite five previous attempts. The RTOs' $1.6 billion Joint Targeted Interconnection Queue transmission portfolio is to be paid for by interconnecting generation and is considered separate from their coordinated system plans.

Mahan said some of the project ideas appear to potentially boost transmission capacity to allow more MISO Midwest-South power flows. He asked if MISO would examine some projects for that value.

Moore said while MISO and SPP are time-constrained for this study, MISO plans to keep the list of projects ideas to draw on in future planning studies.

MISO-SPP TMEPs in the Works

Meanwhile, work will continue into 2026 on MISO and SPP rules to create a smaller, congestion-relieving interregional transmission project category.

MISO and SPP are in the process of drafting rules for a targeted market efficiency project (TMEP) type, modeled after the MISO and PJM existing interregional study that produces less expensive transmission projects that can be built quickly.

SPP Senior Interregional Strategist Jill Ponder said MISO and SPP plan to file new language to their joint operating agreement and an RTO-to-RTO cost allocation for TMEPs in either the first or second quarter of 2026.

Speaking at MISO's August Planning Advisory Committee meeting, Moore said MISO and SPP view TMEPs as a "bridge in our planning toolbox" and said any MISO-SPP TMEPs will not "undermine or duplicate planning efforts."

MISO stakeholders in written feedback expressed a concern that TMEP planning could risk overlapping with the existing MISO and SPP regional and interregional studies.

So far, the MISO and SPP draft TMEP study process would rely on historical data to weed out congestion on the seam and advance small transmission projects that can be built quickly to alleviate it. Moore said TMEPs are intended to supplement — not replace — long-term planning initiatives like MISO's long-range transmission planning and the MISO and SPP Joint Targeted Interconnection Queue. Moore said TMEPs would solve only issues not expected to be "substantially alleviated by system changes" on a five-year horizon, including known upgrades.

Moore also said the two RTOs are striving to make the new process as transparent as possible. She said the RTOs will post historical congestion data annually and will commit to documenting the screening of potential projects in study reports "to explain why some move forward while others don't." ■

MISO Rationalizes Load Forecasting Pilot Program

By Amanda Durish Cook

SIOUX FALLS, S.D. — MISO leadership shed more light on the RTO's need for a pilot program to estimate load growth on a 20-year horizon after stakeholders asked for details.

MISO Executive Director of Markets and Grid Research DL Oates said MISO has fielded stakeholder questions since announcing its load-forecasting pilot. He said the many questions are a "flag" that it should better explain its plans. (See *MISO Debuting Pilot for Better Long-term Load Forecasting*.)

Oates said dramatic load growth is arriving just as MISO is experiencing tapering margins due to continued fleet change.

"All of this makes long-term planning more important and more difficult," he said at the Organization of MISO States' annual meeting Oct. 21.

He said MISO would update its late 2024 forecast and maintain annual load forecasting updates informed by future annual surveys.

What's Next

MISO plans to reveal new, 20-year load estimates sometime in early 2026.

In its 2024 load forecast *edition*, MISO predicted its 638 TWh of gross energy in 2024 would grow to anywhere from 921 to 1,225 TWh by 2044, driven mostly by data centers, electric vehicles and green hydrogen.

MISO previously said it could be navigating an annual peak around 140 GW by 2035. MISO's 2025 summer peak nearly brushed 122 GW.

"It's clear that new information has come to light since last year," Oates said, adding that the pilot forecast would be "pretty exploratory."

He said MISO doesn't know how many members would respond to its survey and added that MISO likely would have to augment some questions in the next survey to improve data quality of responses.

Oates said MISO expects 13.8 GW in load additions in the near-term based on members' expedited transmission project requests. But he said green hydrogen and electric vehicles likely would take a hit in MISO's load forecasts due to policy changes within the federal government.

MISO plans to unveil its updated load estimates sometime in early 2026 after assembling member and national data.

In an early October *letter* answering FERC Chairman David Rosen's questions about MISO's large load forecasting, CEO John Bear said MISO recognizes "that more work must be done to address the new large load challenges, including leveraging new technologies and enhancing our processes."

Bear said MISO's pilot survey would help "shape enhancements to future long-term load forecasts." ■

DL Oates, MISO (left) and Tricia DeBleeckere, OMS | © *RTO Insider*

OMS Meeting Speakers Stress Importance of Transmission Planning

By Amanda Durish Cook

SIOUX FALLS, S.D. — At a time when MISO's long-term planning is under fire, the Organization of MISO States' annual meeting featured speakers who vouched for the power of planning.

MISO Vice President of System Planning Aubrey Johnson said exploding load growth makes the RTO's long-range transmission planning even more relevant. He also said the rigor MISO applies to its scenario-based transmission planning makes ensuring projects a "least-regrets" route.

Speaking at the Oct. 21 event, Johnson said a single data center can "sign on the dotted line" and alter a load-serving entity's integrated resource plan. He cautioned the industry against making "knee-jerk reactions" to policy changes and new reliability assessments.

"It doesn't mean that when those decisions were made three years ago, they were wrong," he said of grid planning. "I would encourage us to have a little more patience and see this as a signal."

Johnson said when MISO refashioned its 20-year transmission planning futures in 2019, growing load was a concern. By 2022, flat load estimates influenced an update of the RTO's futures.

"Both of those cases have prepared us for the generation coming online," Johnson said of the latest upswing in load forecasts, which are set to shape more long-term transmission planning from the RTO.

Why This Matters

Topics at the Organization of MISO States' annual meeting in Sioux Falls, S.D., gravitated toward transmission planning as MISO awaits a FERC decision on the complaint against its long-range transmission plan portfolio.

A panel underway Oct. 21 at the OMS annual meeting at the Canopy by Hilton Sioux Falls Downtown | © RTO Insider

Johnson said MISO's work to install a 765-kV backbone through its long-term planning has apparently inspired neighbors PJM and SPP to draw up their own plans.

But MISO's second, $22 billion long-range transmission portfolio has attracted criticism in the latter half of 2025.

FERC Commissioner Lindsay See used a recent FERC docket to warn MISO that it should be presenting a more complete picture of the needs behind its transmission planning. That's in addition to the pending North Dakota-led complaint doubting the value of the portfolio. (See *FERC Orders MISO to Describe Merchant HVDC Planning Considerations* and *MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan*.)

Terry Wolf, COO of Missouri River Energy Services, said he worries his territory — which exists at the MISO-SPP seam in Iowa, Minnesota, North Dakota and South Dakota — risks being left behind between the RTOs' separate 765-kV plans. He asked that the RTOs pay attention to the burgeoning chasm at their boundaries and plan interregional links.

"Two regions that are tightly intertwined, in my opinion, must do that," Wolf said.

Clint Savoy, SPP manager of interregional strategy and engagement, said his RTO's burgeoning 765-kV portfolio would likely eventually lead to both grid operators examining how to best connect their high-voltage networks.

"I think we'll have an opportunity to do that over the next few years," Savoy said.

Outgoing OMS President Joseph Sullivan, a member of the Minnesota Public Utilities Commission, said he is excited about the prospect of MISO tapping into the West through interregional transmission. He said new transmission routes could deliver more reliability benefits, more diverse resources and economic advantages.

"From my perspective, it's absolutely worth a deep conservation: How do we look further West?" Sullivan said.

OMS spent much of 2025 in "reactive mode" responding to others' decisions, Sullivan continued. He referred to MISO's multibillion-dollar transmission planning, the RTO's interconnection queue fast lane, explosive load growth and federal policy whiplash.

"The agenda was often set for us," Sullivan said. He urged OMS in 2026 to "carve out space to truly set our own active agenda" in the face of immense change. "This coming year will test our cohesion," he told his fellow state regulators.

Christina Drake, MISO's director of economic, interregional and policy planning, said the RTO's 765-kV plans can support about 100 GW of generation and provide a foundation for interregional planning.

Drake added that stakeholder meetings can get "spicy" when RTOs start debating the benefits of transmission investment. But she said stakeholders who aren't motivated by the prospect of expanded transfer capability alone might be persuaded by a "confluence" of increased transfers plus reliability benefits plus congestion-saving benefits. She said outlining the multiple benefits of transmission solutions is paramount after engineering analyses are completed.

However, Drake argued, affordability matters more to MISO South members, regulators and ratepayers than in the RTO's northern regions.

"The best transmission [projects] are the ones folks are willing to pay for and can be sited. That's a tall order," she said.

Wisconsin Public Service Commissioner Marcus Hawkins said the best case for transmission could be the "undeniable value" it provides during widespread extreme weather events.

The OMS annual meeting took place at The Steel District in Sioux Falls, S.D. | © *RTO Insider LLC*

Savoy said it's important to figure out how to quantify the resilience benefits, noting that as more time passes between lived events, the more the perceived value of transmission solutions fades. As an example, he said the premium that civilians and utilities placed on continued supply and power restorations during February 2021's Winter Storm Uri changed dramatically just a few years later.

Ryan Fedie, founder of consulting firm Axelergy, said the "whipsawing" between presidential administrations makes grid investments a tough call. He said that instead of "speed to market," the Trump administration is fomenting "speed to mistrust."

Minnesota PUC Commissioner Joseph Sullivan | © *RTO Insider LLC*

Fedie said he wants to make sure the system is expanded adequately and includes distributed energy resources and demand-side options to avoid overbuilding. He said the existing system "was built on a different model in a different era."

Chelsea Loomis, the Western Power Pool's regional transmission planning services manager, said there's much to tackle regarding coordination on load and generation projections. She said when she worked at Northwestern Energy, the utility fielded about 10 separate interconnection requests from a single customer concerning the same load. Data centers, Loomis warned, can utility shop and "FUBAR" load projections and generation plans.

Loomis joked that she was grateful she was not that close to the audience before saying regulators should be doing more to demand more standardized growth information. She said there's currently a lot of flexibility in commissions' reporting requirements.

Johnson said meeting the moment of load growth paired with the energy transition is not "one quantum shift, but a series of incremental shifts." He said MISO's work on load projections, resource adequacy assessments and transmission planning often produces a "tension" between it and its members that shapes solutions. He told regulators to expect more work from the RTO on interconnection queue to speed up interconnections to the expanding system.

"Nobody's talking about how bored they are," Johnson joked of the zeitgeist in the energy industry. ■

MISO Vice President Aubrey Johnson (left) and Western Power Pool's Chelsea Loomis | © *RTO Insider LLC*

NYISO: Winter Reliability Proposal to Increase Market Efficiency

By Vincent Gabrielle

Under the scenarios considered in NYISO's consumer impact *analysis* for the Winter Reliability Capacity Enhancements project, installed capacity procurement costs would drop by 15 to 45% depending on locality.

"Overall, the market design proposal is likely to improve market efficiency," Nicole Bouchez, senior principal economist and consumer interest liaison for NYISO, said at the Installed Capacity Working Group meeting Oct. 14. "Seasonal minimum ICAP requirements more accurately represent future system needs."

The study assumed the proposed market design changes for the winter reliability project were implemented. Those changes included: seasonal unforced capacity deliverability rights/external capacity deliverability rights with a must-offer component; distinct winter/summer minimum ICAP requirements; and removal of the seasonal adjustments in the seasonal ICAP demand curve.

© RTO Insider

Scenario 1 assumed the Champlain Hudson Power Express (CHPE) was not in service and that the Gowanus and Narrows generators were not retired. Scenario 2 assumed CHPE was active only in the summer and Gowanus and Narrows were retired.

In Scenario 1, ICAP market procurements fell statewide by 15%, with some variation among the different zones. In Scenario 2, procurements overall fell by 45% but increased locally on Long Island from $32.48 million to $36.15 million during the study year.

Sensitivities were conducted to look at expected imports and exports. Maximizing net imports to their historical heights decreased procurement costs. Maximizing net exports increased procurement costs but still provided overall savings to consumers.

Bouchez said the seasonal market design likely would improve market transparency and provide better price signals for both market exit and entrance. No environmental impacts were identified, but the new market design may increase the potential profitability of new technologies (like batteries) entering the market.

Why This Matters

The Winter Reliability Capacity Enhancements project will split the ICAP market into seasons with separate ICAP requirements. This would have a dramatic effect on capacity pricing statewide.

The ICAP Working Group also discussed the *tariff* and manual *revisions* for the winter reliability project. The target implementation for the tariff changes is May 2027, with a filing at FERC in the first quarter of 2026.

Doreen Saia, chair of Greenberg Traurig's energy and natural resources practice, expressed concern that NYISO is lumping substantive tariff and manual edits with administrative ones.

"The NYISO cannot keep bunching together what appear to be ministerial 'nothing to see here' changes and then lop on something that does matter and is important and package it together," she said. "Market participants are running to keep up with you."

Another stakeholder agreed, saying stakeholders want to talk through the issues before the manual or tariff language is put in front of a committee.

These comments were in response to NYISO's inclusion of revised manual rules that apply to generators that are placed into an ineligible forced outage. The ISO highlighted several sections of the manual that it thought needed clarification and presented revisions.

Mike Cadwalader of Atlantic Economics also pointed out that the manual revisions did not come with a sample case to illustrate how the rules functioned. ■

NYISO Stakeholders Debate New York City Reliability Need

By Vincent Gabrielle

Stakeholders spent much of the Electric System Planning Working Group's meeting Oct. 20 debating the validity of NYISO's recent finding of a reliability need in New York City by summer 2026.

In its third-quarter Short Term Assessment of Reliability (STAR), the ISO said there would be a shortfall in the city if several ongoing projects — including the Champlain Hudson Power Express (CHPE), Empire Wind and the Propel NY Transmission Project — fail to be energized by their anticipated in-service dates. The projects would provide the power that would be unavailable from the planned retirements of the Gowanus and Narrows generators. (See *NYISO Again Identifies Reliability Need for NYC*.)

"Until these plans are completed and demonstrate their power capabilities, the identified reliability needs in New York City would continue to remain," said Keith Burrell, a transmission planning adviser for NYISO.

Stakeholders tried to get the ISO to clearly articulate how likely it might be that that CHPE would be in service by the second quarter of 2026, potentially solving the nearest-term reliability need for New York City.

"I guess I'm trying to understand whether CHPE needs to be proposed as a solution or is it a solution that is going to be looked at in each STAR?" asked Tony Abate, representing the New York Power Authority.

Another NYISO staff member repeated Burrell, saying that once CHPE has demonstrated its ability to provide power, that would be a solution.

"I'm struggling to understand what has changed in the last 90 days," said Howard Fromer, director of regulatory affairs for Bayonne Energy Center, referring to the most recent STAR. "It can't be the load. Has it materially changed from what you were using in the Q2 STAR?"

"We've been identifying needs in the STARs all along and continue to identify CHPE as a potential solution," Burrell said. He pointed to a figure in the most recent report that illustrated the city's transmission security margin. According to those forecasts, if CHPE entered service as planned, there would not be a deficiency until 2029.

Why This Matters

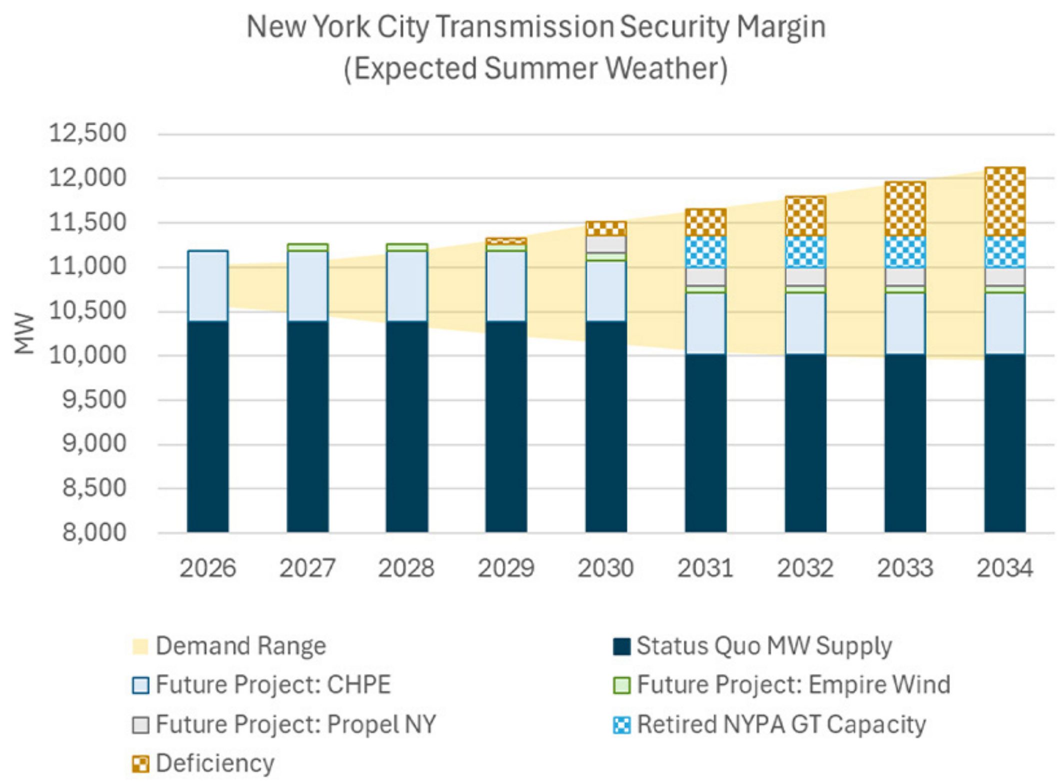
NYISO recently found a reliability need in New York City because of local generator deactivations, but it is based on whether ongoing transmission projects like the Champlain Hudson Power Express come online on time.

After some discussion about what future STAR reports might look like if CHPE came online as expected, the ISO clarified that each STAR was a snapshot of system conditions in time. If a project, or deactivation, meets the base inclusion criteria, it gets into the latest STAR.

"I think what people are trying to identify is, 'What is the next step?'" said Yachi Lin, director of system planning for NYISO. "And the next step is that NYISO will be soliciting [solutions] starting in early November. In that solicitation we will have more details about the solicitation type."

Lin said that a market-based solution that could potentially come online earlier to serve the need found in the STAR would be "something for the NYISO to consider."

"But we don't know yet what the kind of proposed solution or answer to the solicitation is. It's difficult for us to forecast what the outcome is going to be," Lin said. ■



| NYISO

Economic Uncertainty Looms over NYISO Conference

New York Outlook Buoyed by Local Factors

By Vincent Gabrielle

Presenters at NYISO's 2025 Fall Economic Conference painted a confusing portrait: Conflicting evidence between a weak labor market and overall economic growth leaves uncertainty about whether the economy might tip into a recession.

"I could have just presented a 'shrug' emoji and just left for the next few hours. But I feel like that probably would not have been that enlightening," said Adam Kamins, senior director of Moody's Analytics. "Instead, we'll try to walk through all the different sources of uncertainty."

NYISO engages Moody's to present on state and federal economic trends twice a year as part of the Load Forecasting Task Force. Economic outlook is a major component of load growth.

In the Oct. 23 presentation, Kamins showed an index of employment gains across 260 industries from the Bureau of Labor Statistics. Over the previous six months, the balance of industries adding *versus* shedding jobs tipped in favor of shedding. Monthly growth in non-farm payroll has flattened, according to the BLS.

Another point of concern in the labor market is the sharp decline in immigration due to a Biden executive order in June 2024 capping asylum requests. That was followed by President Donald Trump's dramatic increase in immigration enforcement actions and deportations. This has led the foreign-born share of the labor force to contract.

"We are seeing hiring at very, very low levels," said Kamins. "The way firms are hiring is consistent with the kind of thing you would see during a recession."

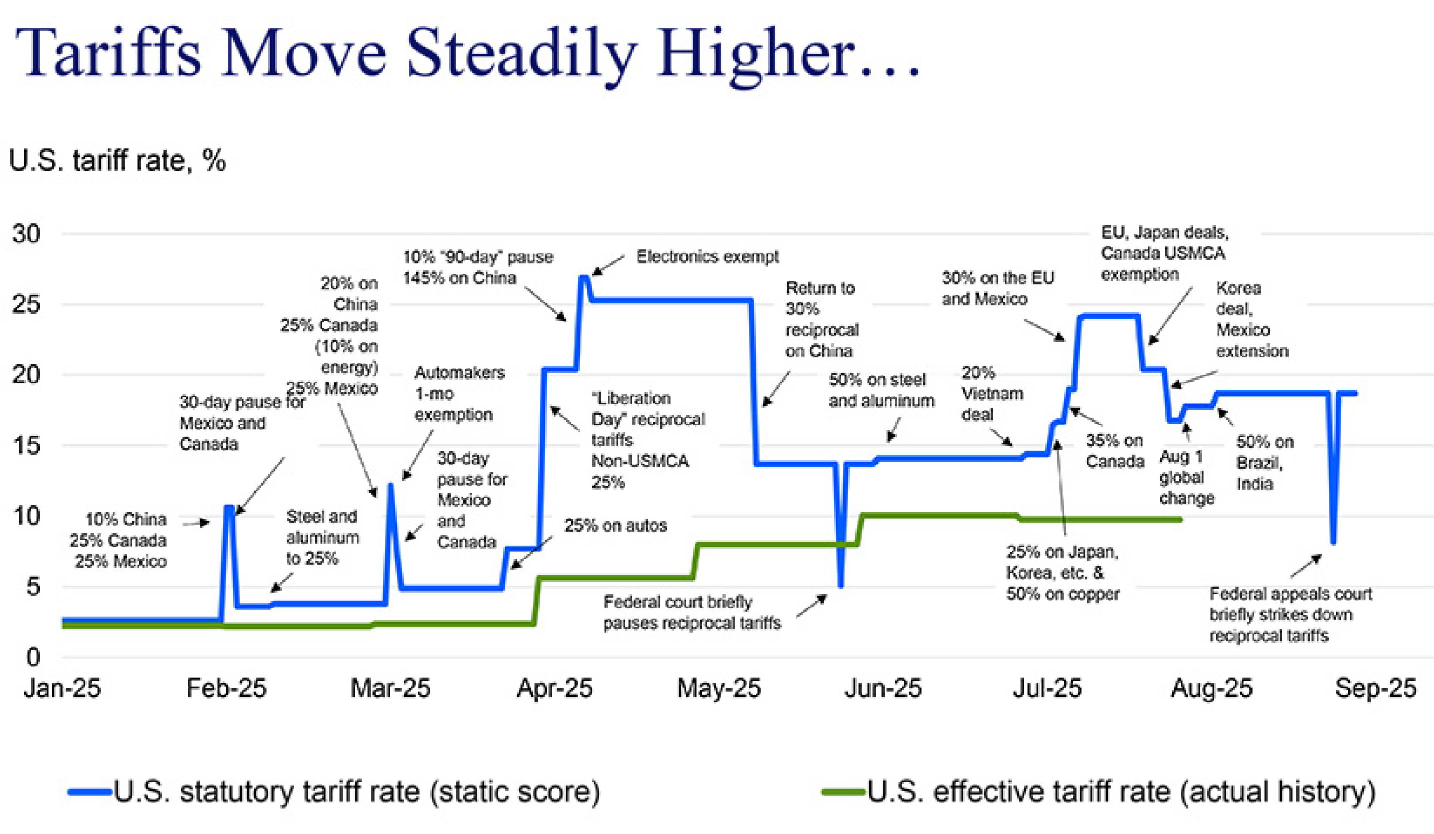
Firms are "just sitting tight" on their workforces, said Kamins. Companies are waiting to see where the economy is going.

A stakeholder asked whether Kamins and other economists had considered the "integrity" of data coming out of the Trump administration. Kamins pointed at the firing of BLS head Erika McEntarfer in June when the jobs data were not to Trump's liking. While the BLS largely was staffed by "apolitical civil servants," Kamins explained, if the administration puts political actors in charge of the bureau, that could damage the credibility of BLS data.

"We've started to think about what other

Why This Matters

Economic projections are a major element of load forecasting. Recession can mean reduced electricity demand, and an uncertain economy makes load forecasting tricky.



| Moody's

ways can we verify the data we're getting from the BLS," Kamins said. While he wasn't as worried about the BLS as he is about the Federal Reserve, Moody's is taking steps to confirm government figures. "We've done some of the work to create our own indexes of other sources out there. Bottom line, yes, it's a concern."

Later in the presentation, Kamins showed a timeline of the effective U.S. tariff rates and the statutory increases that have bounced around since Trump took office. He said the effective U.S. tariff rate was higher than it had been since 1920. A survey from the Federal Reserve Bank of Dallas found that more than 75% of manufacturers intended to pass on tariff costs to consumers, and 50% said they were absorbing costs internally.

"There are some that are doing both," said Kamins. "There was a lot of action to make the impact of tariffs not necessarily that evident to consumers."

Eventually, this would increase costs across the economy, which in turn would create inflationary pressure, Kamins explained. Tools and hardware, vehicles, bicycles, jewelry, meat, poultry and fish are places where you can find evidence of tariff-based price increases.

This increased price pressure makes it difficult for the Federal Reserve to balance its targets in the job market and inflation. Kamins added this is even more difficult because of the administration's erosion of Fed independence.

"Any day now there's going to be a nominee for who will be the next Fed chair," Kamins said. "I think that will be a very telling indicator of where things are headed. Whether there's going to be a political operative or if it's someone who is generally respected in the economics community."

New York's Resilient Economy

While the nation might be experiencing an overall decline in job growth, New York's labor market is healthier, Kamins said. The labor market is anchored by hiring in state government, health care, education and construction. New York's consumer sentiment is higher than the U.S. average, meaning that people feel better about the economy in New York than elsewhere.

Several metro areas in New York are experiencing economic expansion, particularly Albany, Kingston and Rochester. The upstate city of Glens Falls is a trouble spot. Kamins said it was more reliant on Canadian tourism than other areas of the state and likely already is in recession.

Some of this growth is from the state's lack of reliance on federal money. According to the state comptroller, New York historically has been one of the few states to put more money back into the federal government than it receives. As of the most recent *report*, New York had not fully returned to this pre-pandemic norm, but it was getting close.

"It's a bit of a good-news, bad-news situation," said Kamins. "The good news is that New York is not as dependent on federal government expenditures as some of its peers. … The bad news is that by no means is New York immune from potential cuts."

Kamins said New York faced the most risk from federal funding cuts through programs like Medicaid. New York and Minnesota were the only two states that signed a provision of the Affordable Care Act, the Basic Health Program, to create a state-administered public option. If that were cut, New York would get hit harder than most other states.

New York also is heavily dependent on microchip fabrication for its upstate economic outlook. Without the impact of the new Micron chip fabrication center, upstate economic outlook looks much bleaker.

Housing prices have begun to level off statewide as more supply comes onto the market. Prices are high, and that likely will drive office-to-apartment conversions in markets like New York City. Supply-constrained areas like Rochester and Monroe County have seen supply gains more rapidly than other areas of the state. ■

Options for Clean Dispatchable Power Each Have Caveats

N.Y. Report Lays out Potential Advantages, Challenges of 7 Technologies

By John Cropley

Why This Matters

The report comes as the state's clean-energy transition lags well behind the timeline envisioned for it. State officials expect to miss the 2030 statutory goal of 70% renewable energy, perhaps by a wide margin.

All seven clean energy technologies evaluated for a new report might someday help New York reach its decarbonization goals, but each would require innovation and support to reach that potential.

The authors say that while hydrogen, biofuels, advanced nuclear, carbon capture and storage, next-generation geothermal, long-duration energy storage and virtual power plants all are in development, none exists at a scale to serve as a dispatchable emissions-free resource to backstop all the intermittent wind and solar generation New York wants to build.

The New York State Energy Research and Development Authority submitted the "*Zero by 40 Technoeconomic Assessment*" to the Department of Public Service on Oct. 22 (*15-E-0302*).

The report was prepared by the Electric Power Research Institute. Its title alludes to the state's statutory goal of a zero-emission power grid by 2040.

The Public Service Commission in May 2023 ordered the report to identify methods of closing the gap between existing renewable energy technologies and future system reliability needs.

The cost and complexity of all-new or greatly expanded infrastructure is likely to be a limiting factor in the near term, giving a larger role by default to technologies that would not require significant infrastructure upgrades, the authors wrote.

The report comes as the state's clean-energy transition lags well behind the timeline envisioned for it. State officials expect to miss the 2030 statutory goal of 70% renewable energy, perhaps by a wide margin. Delayed fossil retirements or even new fossil generation are being contemplated as a result.

The report groups the seven technologies evaluated into three functional categories: low capacity factor resources to deploy at peak system need (hydrogen and biofuels); high capacity factor resources that can a provide firm supplement to renewables (advanced nuclear, next-generation geothermal and CCS attached to thermal plants); and filling gaps with resources to balance supply and demand (long-duration storage and VPPs).

Hydrogen

Hydrogen can be a zero- to low-carbon energy resource, depending how it is produced. Economywide demand for hydrogen would be the most economical scenario; building a bulk underground storage and pipeline transport system just for the power sector would be costly.

Pipelines are expensive and slow to build. But without them, the cost and logistics of statewide use of hydrogen for power grid reliability would be prohibitive.

The greatest near-term opportunity appears to be in upstate New York, if low-cost or curtailed renewable electricity could power hydrogen production co-located with geologic storage.

However, there may not be excess renewable electricity to generate hydrogen in 2040, and the cost of hydrogen is expected to be significantly higher than natural gas.

Biofuels

Renewable natural gas (RNG) and renewable diesel (RD) are the biofuels most relevant to the power sector because they are drop-in replacements for natural gas and distillate fossil fuels.

RNG has relatively few infrastructure needs, but its feedstocks are limited and are required for decarbonization of other sectors. So RNG would most likely serve as a peaking resource. The air-quality impact of RNG combustion depends on whether it is evaluated by net emissions, which are zero or close to zero, or by gross emissions, which are similar to natural gas.

RD may be particularly important to New York's grid as it shifts to a winter-peaking system. But it is expected to be significantly more expensive than fossil distillate, and it is less efficient than RNG in combustion turbines.

Biofuels and hydrogen have near-term supply constraints, but the availability of hydrogen has the potential to outstrip biofuels because of the finite supply of biofuel feedstocks.

Advanced Nuclear

Nuclear reactors are expensive; operating them at a high capacity factor is more economical. So while advanced reactors are expected to be capable of more flexible operation than today's conventional fleet, they are likely to remain baseload power.

Developing any new nuclear generation in New York by 2040 will require early and careful planning, as the timeline may stretch a dozen years per facility, unless federal intervention or economies of scale speeds up the regulatory and construction process.

Carbon Capture and Storage

CCS can be used on a natural gas-fired peaker plant, but it is best used on baseload power plants because it is expensive and less efficient on an intermittent basis.

CCS would require significant buildout of transport and storage infrastructure that does not exist in New York. Such an ecosystem would face challenges in regulation, permitting and public acceptance but could benefit hard-to-decarbonize industrial applications.

Even a carbon capture rate of nearly 100% would not make a significant reduction in upstream emissions totals as tallied by New York's greenhouse gas accounting system.

Geothermal

The geological landscape of New York is largely unexplored for its geothermal power potential, but the potential is believed to be quite low — less than 1 GW by 2040 — using existing technology.

But in the longer term, with continued technological innovation, there is a theoretical potential for greater use of the earth's heat to generate electricity in New York. The cost of such an effort is highly uncertain.

Long-duration Energy Storage

Short-duration storage (less than 10 hours) presently can meet most grid-balancing needs, but greater reliance on renewable power will require larger capacities and longer durations of storage.

The report examines 18 electrochemical, mechanical and thermal energy storage technologies capable of operating for durations greater than 10 hours.

Electrochemical and mechanical technologies generally are more ready for deployment. Electrochemical technologies are more modular and can provide more grid services but come with safety considerations, higher costs and shorter lifetimes. Thermal technologies potentially are useful for industrial decarbonization.

All come with round-trip efficiency losses, and some with standby losses.

Emerging technologies must be assessed to mitigate any risks as they move from early development to deployment.

Electricity market design changes are needed to support market-based deployment of long-duration storage.

Virtual Power Plants

VPPs could serve as a key intermediary between flexible distributed energy resources and load-flexible appliances.

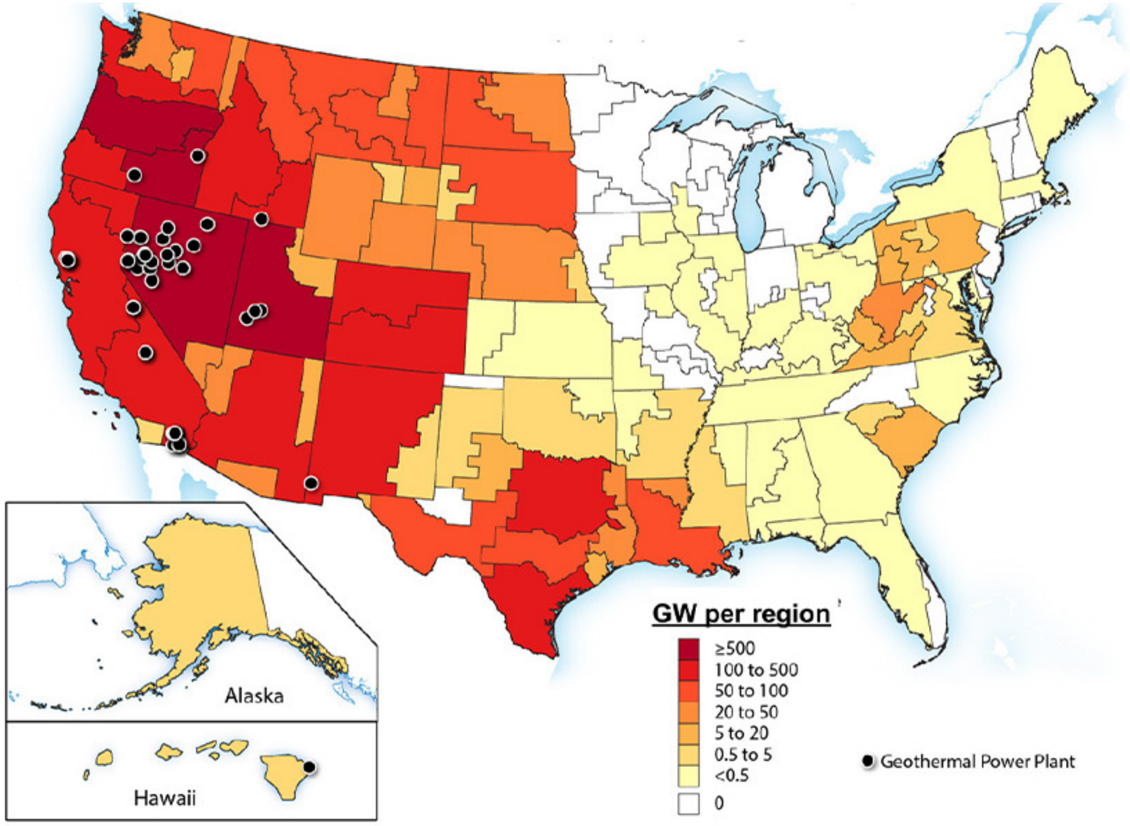
A recent study showed VPPs could reach 8.5 GW of flexibility potential in New York by 2040, a cost-effective approach to balancing supply and demand.

VPPs carry low capital costs and short lead times, but realizing their potential would require improving customer recruitment and participation; standardizing communications and market interfaces; and addressing metering and telemetry costs. Programs with easier enrollment and reduced user interface are expected to have the greatest impact.

Where to Begin

The report identifies several no-regrets actions the state can take to set the stage needed for its 2040 goals:

- Do not overly rely on one technology; pursue a diverse portfolio.
- Start early.
- Invest in grid-enhancing technologies to reduce the need for backstop resources.
- Invest in innovation.
- Develop strategies across industries to overcome infrastructure hurdles.
- Engage early with developers, end users and other stakeholders.
- Model a range of costs and performance attributes of technologies to deploy.
- Reassess options regularly and remain flexible as new options become available. ■



One of the technologies New York evaluated for future energy needs is geothermal. A U.S. Department of Energy map shows indicates limited known resources in the state. | *DOE*

DOE Extends Order Lifting Run Hour Limits on Md. Generator

By Devin Leith-Yessian

The U.S. Department of Energy *approved* PJM's *request* to extend an *order* allowing Talen Energy to continue operating its oil-fired H.A. Wagner Unit 4 to exceed the 438 hours it is permitted to operate each year.

The Oct. 24 order allows the 397-MW generator, located outside Baltimore, to continue operating for 80 days to mitigate the risk of load shed during "certain system conditions or transmission limitations" within the Baltimore Gas and Electric (BG&E) region. The order lifts the run hour limit when PJM declares or anticipates a maximum generation alert or transmission security emergency. (See *DOE Lifts Run Hour Restrictions on Maryland Generator*.)

"PJM anticipated that, for the remainder of 2025, there will be a continued need to schedule Wagner Unit 4 in order to maintain reliable system operations during projected peak demand and/or increased flows on transmission facilities that are required to serve the BG&E Zone," the order states. "Additional circumstances that could cause the need for increased scheduling of Wagner Unit 4 include high system demand, additional transmission facility outages, and generation outages or a combination of these factors."

In its application asking DOE to exercise its Federal Power Act (FPA) 202c authority, PJM said the EPA and Maryland Department of the Environment (MDE) informed it that the consent order imposing the run hour limitation would not be able to be modified within 2025 and it has taken steps to avoid dispatching the unit as much as possible.

H.A. Wagner Generating Station outside Baltimore | *Acroterion, CC BY-SA-4.0, via Wikimedia Commons*

Why This Matters

The DOE's extension provides PJM more generating capacity cushion under tight supply conditions.

PJM to Seek Extension of Order Defining Wagner, Brandon Shores as Capacity

PJM Senior Counsel Chen Lu outlined the RTO's intention to ask FERC to include Wagner and the adjacent 1,289-MW Brandon Shores coal-fired generator in the capacity market supply stack for the 2028/29 Base Residual Auction (BRA), extending an order defining the two resources as capacity in the prior two auctions (ER25-682). (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

PJM's governing documents allow reliability must-run (RMR) units to be exempted from the requirement that resources offer into the capacity market.

However, against a backdrop of tightening supply/demand balance, consumer advocates argued that if the generators are being relied on for transmission security, it should also be assumed that they will be available during capacity deployments. Opponents of that stance protested that including RMR units in the supply stack would distort market signals and suppress the prices needed to bring on replacement resources.

The commission's order was limited to two delivery years to give PJM time to work toward a *pro forma* RMR agreement that defines resources as capacity. That effort is ongoing in the Deactivation Enhancement Senior Task Force (DESTF), where PJM has presented a draft pro forma *agreement*.

"It's really a stop gap for these two Talen units," Lu said, adding that it doesn't make sense to shift the two generators onto an eventual *pro forma* agreement since they're already operating under a FERC-approved RMR. ■

PJM Board of Managers Approves Quadrennial Review Proposal

By Devin Leith-Yessian

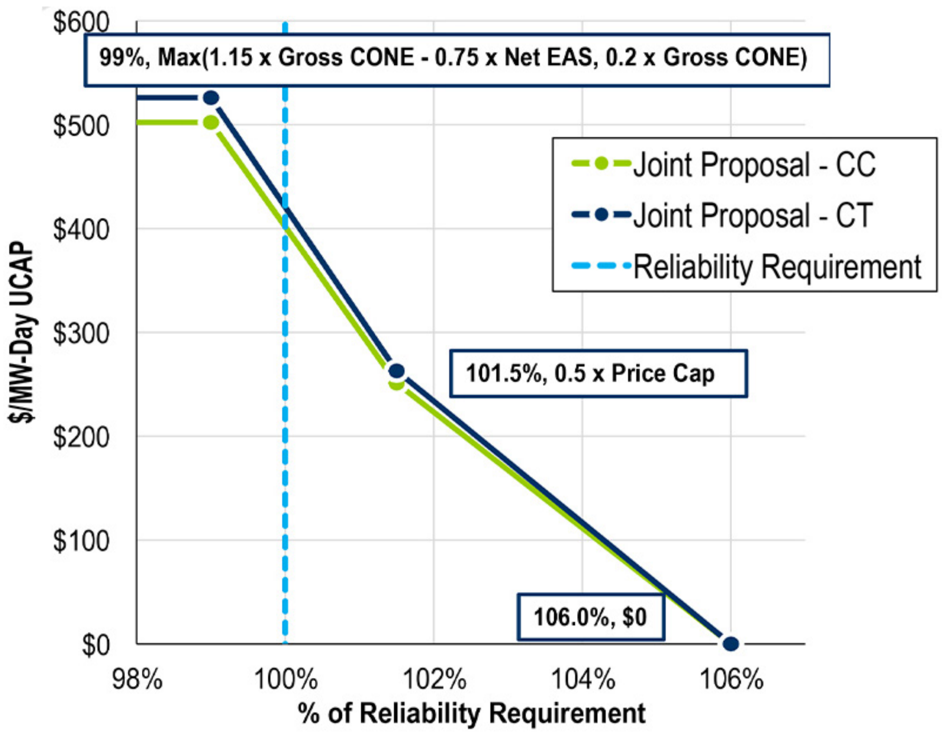
The PJM Board of Managers has directed staff to proceed with a Quadrennial Review *design* that reworks the capacity auction price curve and sets the reference resource as a combustion turbine for all zones. (See *PJM MIC Endorses 2 Quadrennial Review Proposals*.)

"The board believes this proposal strikes the appropriate balance of reliability and cost implications," it said in an *announcement* posted Oct. 22. It also noted that the proposal, jointly sponsored by PJM staff and Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow, was the only one to be supported by the Markets and Reliability Committee.

Six proposals were considered by the Market Implementation Committee over the past year, with two being endorsed in September. The PJM/Barrow proposal received 75% sector-weighted support at the MRC. PJM spokesperson Jeff Shields told *RTO Insider* that staff intend to file the proposal within the next few weeks.

The proposal aims to improve the stability of the variable resource requirement (VRR) curve by reducing reliance on multipliers of the cost of new entry (CONE) parameter; the curve defines the clearing price to be procured in a Base Residual Auction (BRA) and at what cost.

It would shift the design of the VRR curve to set the maximum price at the larger of either 20% of the gross CONE, or 115% gross CONE minus 75% of the net energy and ancillary services offset. The formula establishes a floor meant to prevent high energy market revenues lowering the maximum capacity price to zero. The curve approved by the commission in 2023 set the maximum at the greater of gross CONE or 1.75 times net CONE, which subtracts the EAS offset from gross CONE. (See *FERC Approves PJM Quadrennial Review*.)



PJM's recommended variable resource requirement (VRR) curve | *PJM*

The midpoint on the curve would procure 101.5% of the reliability requirement at half of the maximum price, which is also meant to improve the stability of the curve. The midpoint for the prior curve was set at 75% of net CONE and 101.5% of the reliability requirement.

The curve would reach zero at 106% of the reliability requirement, shifting further to the right from the 104.5% anchor used in the previous curve shape.

During the Sept. 25 MRC meeting, PJM's Skyler Marzewski said there is little difference in the maximum price when the curve is based on a combined cycle reference resource, the RTO's preference, and a CT. The maximum would fall between $483/MW-day of unforced capacity in CONE Area 3 and $785/MW-day for ComEd. Some areas would see a lower maximum using a CC reference resource, such as a $463/MW-day maximum for CONE Area 3, while it would be higher in ComEd at $841/MW-day.

PJM's original proposal sought to use a four-hour battery electric storage system as the reference resource in the ComEd region and a CC in all other CONE areas. Marzewski said a curve based on storage for ComEd would reflect environmental restrictions in Illinois that would reduce the lifespan of new gas generation. Instituting a CC for the other regions would reflect development trends in the region, with several CCs in the interconnection queue. (See "Stakeholders Divided on Reference Technology," *PJM Stakeholders Discuss Quadrennial Review Proposals*.)

PJM had intended to shift to a CC in the last Quadrennial Review but backtracked when it determined that high estimated energy prices could cause capacity prices to fall to zero, along with disruptions to other parameters based on the reference resource. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

PJM's proposal adopted Barrow's recommendation to use the 67th percentile of the net EAS offset for each CONE area, which Marzewski said is meant to reflect that developers will seek to maximize their potential revenues when siting projects. ■

PJM Promotes 3 Executives as CEO Search Continues

By Devin Leith-Yessian

PJM has promoted a trio of executives while it continues its search for a new CEO.

"This new structure will strengthen our executive team and allow the incoming CEO to focus early on the external work of building strong relationships with stakeholders, regulators and state leaders, and navigating the evolving energy landscape," David Mills, chair of the RTO's Board of Managers, said in an *announcement* of the leadership changes. (See *PJM CEO Manu Asthana Announces Year-end Resignation*.)

Stu Bresler was elevated to COO from executive vice president of market services and strategy, putting him in charge of core departments such as operations, markets and planning. He has been with the RTO for more than 30 years.

Executive Vice President of Operations, Planning and Security Aftab Khan was promoted to chief strategy officer, setting him up to "lead cross-functional initiatives and drive organizational transformation to ensure sustainable success and alignment," according to the announcement. He served as senior vice president of engineering for Eversource Energy before joining PJM in 2024 and previously worked at General Electric and ABB.

Stu Bresler, PJM | © *RTO Insider*

Adam Keech, PJM | © *RTO Insider*

Vice President of Market Design and Economics Adam Keech was made senior vice president of market services. He has been with PJM since 2003, having overseen NERC compliance and real-time market operations, among other roles.

PJM spokesperson Jeff Shields said the new titles redefine the three executives' duties, and the prior positions will not be backfilled. He noted that PJM's last COO was Mike Kormos, who left in 2016. (See *PJM COO Kormos Leaving; Post Won't be Filled*.)

The announcement also said the search for a replacement for Manu Asthana, who serves as president and CEO, is proceeding. He announced his resignation April 14, with the intention for it to be effective at the end of 2025.

If a new CEO is not in place by Jan. 1, 2026, Mills will take over as interim president and CEO while the search continues.

"The board is committed to finding the best candidate to lead PJM through the numerous challenges facing the industry, and that meticulous process continues," Mills said in the announcement. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Proposal to Offer Cap Advance Commitments

VALLEY FORGE, Pa. — PJM's Markets and Reliability Committee endorsed by acclamation a *proposal* to use only cost-based offers for resources committed in advance of the day-ahead energy market.

The proposal was also endorsed by the MC as part of its consent agenda. (See "1st Read on Offer Capping of Advance Scheduled Resources," *PJM MIC Briefs: Aug. 6, 2025*.)

The use of advance commitments has grown since PJM implemented its conservative operations protocol, which allows resources to be scheduled days ahead of an event the RTO thinks could strain system conditions. It was established in the wake of the December 2022 Winter Storm Elliott, when many generators had trouble procuring fuel when picked up by PJM dispatchers. (See "PJM Discusses Market Performance During January Winter Storms," *PJM MIC Briefs: Feb. 5, 2025*.)

Paul Sotkiewicz, president of E-Cubed Policy Associates, argued against units being limited to their cost-based offers without evidence of market power issues or when their commitment is intended to resolve a transmission constraint.

He said the proposal represents PJM's attempt to make up for tariff violations during the conservative operations deployment ahead of the 2025 Martin Luther King Jr. Day weekend. Resources with advance commitments were improperly offer capped despite the conservative operations not being related to transmission issues.

He also raised issues about the scope of what can be included in cost-based offers, saying resource owners can incur unrecoverable costs when responding to a conservative operations commitment. He noted that fuel costs can be high during holiday weekends and must be purchased as a block package for the whole weekend.

PJM General Counsel Chris O'Hara said he is comfortable with the proposal from a compliance perspective after conferring with the RTO's legal team and speaking with staff at FERC about the issue.


PJM General Counsel Chris O'Hara | © *RTO Insider*

He said stakeholders have mixed views about how frequently PJM should use offer capping and the RTO has sought to proceed with the best solution available.

LS Power Director of Project Development Tom Hoatson said the proposal provides market participants with more certainty around how they will be committed during conservative operations and that improvements to the expenses captured in cost-based offers fall under phase two of the *issue charge*.


Paul Sotkiewicz, E-Cubed Policy Associates | © *RTO Insider*

Renewable Dispatch Proposal Endorsed

The committee endorsed by acclamation a *proposal* to rework how wind and solar resources are dispatched, including establishing an Effective EcoMax parameter intended to capture how a resource is forecast to operate in how it is dispatched. (See "Renewable Dispatch Proposal Endorsed," *PJM MIC Briefs: Aug. 6, 2025*.)

The forecast feeding into Effective EcoMax would be updated before each five-minute interval in the energy market and define the maximum output of the unit's dispatch. PJM has sought the change to reduce the curtailment of renewable resources with outdated parameters, which the existing EcoMax parameter is limited to.

The ramp rate for wind and solar resources would be limited to 20% of their installed capacity per minute, which is intended to reduce the volatility that can result from sudden shifts in output.

1st Read on GDECS Tariff Revisions

PJM *presented* a first read on a slate of tariff revisions drafted by the Governing

Document Enhancement & Clarification Subcommittee (GDECS), which seek to reflect changes approved by FERC and remove outdated language. The subcommittee approved all of the changes.

The proposal removes language referring to capacity storage and environmentally-limited resources from a section on winter-period capacity performance resources to conform with FERC approving the elimination of an exemption from the requirement that resources offer into the capacity market (*ER25-785*).

A section detailing the penalties for distributed energy resources that fail a test of their capability to respond to capacity deployments would be revised to avoid the potential for double penalization if the event also results in penalties during a performance assessment interval or deficiency charges.

Several changes to Schedule 6A, which lays out black start service, are intended to clarify the capital investments that can be included in the capital recovery factor rate.

Members Committee

1st Read on Changes to Membership Reqs for PIEOUG

Greg Poulos, executive director of the Consumer Advocates of the PJM States, *presented* a first read on a proposal to rework the membership and voting structure for the Public Interest and Environmental Organizations User Group (PIEOUG) to resolve inconsistencies stemming from the Operating Agreement's definition of PJM membership.

A unique user group established under the OA, the PIEOUG is exempt from the requirement that user groups be composed of full PJM members.

He said the user group was intended to include organizations that may not be full PJM Members, signified in the OA by capitalization. However, the voting rules for user groups allowing items to

Greg Poulos, CAPS | © *RTO Insider*

be referred to the Members Committee with 75% support appears to be limited to "Members." Another section of the OA allows items to be referred to the Board of Managers with 90% support from a user group, but uses the lowercase term "members."

The proposal would split PIEOUG membership into two categories: consumer advocates who are PJM Members, as well as environmental organizations and general public interest groups. Both would be permitted to vote on motions to refer items to the MC, with 75% support overall and 50% from both classifications required for the vote to pass. If the MC opts to not take up the subject, the PIEOUG could vote to refer it to the PJM board with 90% support overall and 50% from both categories.

Poulos said the two categories for PIEOUG membership is intended to ensure that state-appointed consumer advocates are not outvoted if a large number of environmental or public interest groups are admitted to the PIEOUG, which chooses its own membership.

Poulos told *RTO Insider* the proposal is intended to find the right balance on giving all members of the user group a voice. He said it's rare for items to be referred to the MC or board and no such votes are being considered at this time.

Stakeholders Discuss MC Annual Plan

MC Vice Chair Jason Barker opened a discussion on whether language in Manual 34: Stakeholder Process detailing the creation of an annual plan is anachronistic. He said the committee has not created a formal plan detailing its priorities to PJM management in recent years, with approval of issue charges instead fulfilling that role.

Carl Johnson, of the PJM Public Power Coalition, said the goal of the annual plan was to ensure items weren't being overlooked. While there were a few successful efforts to establish annual plans years ago, prioritization within the stakeholder process has largely been ceded to PJM staff. While there could be value in a discussion on whether the annual plan should remain in the manual, this might not be the proper time given the other topics stakeholders are focused on.

Tangibl Group Director of RTO and Regulatory Affairs Ken Foladare said PJM has consistently set agendas that provide little time for discussion of important issues, requiring moderators to cut off conversation to move onto other subjects. He noted that the Oct. 14 Critical Issue Fast Path meeting allowed just 30 minutes for questions on stakeholder proposals, leaving individuals unable to participate. If this is repeatedly happening, the RTO needs to either allot more time or discussion should be allowed to go over time.

Barker said some stakeholders routinely engage in time-consuming behaviors, such as cross-examining PJM staff or asking argumentative questions. That may be appropriate at times, but better management of time could allow everyone to have their questions answered. ■

— Devin Leith-Yessian

Golden Spread to Appeal Rejection of Capacity Assessment Change to Board

Z2 Resettlement Begins in November, Faces Long Road Ahead

By Tom Kleckner

LITTLE ROCK, Ark. — Golden Spread Electric Cooperative says it will request that SPP's Board of Directors overturn a stakeholder group's rejection of a proposed tariff change that would preemptively determine the amount of load the existing transmission system can handle without requiring additional network upgrades.

Golden Spread's Mike Wise brought the appeal of the tariff revision request (*RR642*) to the Markets and Operations Policy Committee during its Oct. 14-15 meeting after it gained only 18% approval at the Transmission Working Group in September.

His motion to enable transmission customers and host transmission owners to access load-hosting capacity assessment results failed with only 29.51% approval. SPP's TO members united to vote against the change, 18-0, after citing concerns at TWG over reliability issues with sharing load-hosting capacity and creating operational risks.

A dejected Wise told *RTO Insider* after that he will again appeal RR642 during the board's Nov. 4 meeting. He will also provide a second or alternative motion for the directors' consideration.

"The TWG got it wrong, and we want to try to rectify that," Wise told MOPC. "The bottom line is that we support the SPP staff's position on this RR."

Staff drafted the proposed change to tariff Attachment AQ's screening process following a recommendation from the Holistic Integrated Tariff Team's (HITT) *2019 report*. It would allow SPP to proactively perform analysis to determine load capacity at each node on the system without incremental investment. Information gathered from the load-hosting capacity assessment would determine whether transmission customers would be required to go through an AQ delivery point network study.

Wise, who sat on the HITT, sponsored the recommendation during the team's work. He referred to the proposal as "one of those ancient HITT items that has lingered out there."

Golden Spread's Mike Wise (left) appeals rejection of RR642 to MOPC. | © *RTO Insider*

What's Next

Golden Spread will appeal the rejection of the proposed tariff change at SPP's Board of Directors meeting Nov. 4.

"This gives transmission customers … the same access to the tool and the information as the TOs themselves," Wise said. "It's not being crammed down on them. They own the trump card. Basically, if they say we need to study this, then it's going to be studied, right? I really don't see why the TOs would be against this because they are not going to have to be forced to do something that doesn't work or affects their reliability."

"We are supportive of this tool being used for information purposes, and we just do not feel it's ready for the decision-making process for AQ studies," said Jarred Cooley, with Xcel Energy subsidiary Southwestern Public Service.

"This is just a tool with information. The question is, who should see it and what's the accuracy?" SPP's Natasha Henderson said. "Just like any other tool with information, it's predicated on what we put in that tool. On the [generator interconnection] side, we have a tool that shows where there's room on the system. Well, that's true until you study 90 GW of generation in the 2024 [Integrated Transmission Plan assessment]."

SPP Close to Resettling Z2 Bills

SPP's five-year plan to resolve its Attachment Z2 headache — the "most litigated, drawn-out process we've ever had," according to General Counsel Paul Suskie — will begin in earnest in November.

As part of FERC's directive to submit a compliance filing on its Z2 plan, staff will provide updated balances to entities affected by a 2019 remand order for the refund period (March 2008-August 2015). They will send information to entities wishing to enroll in a payment plan and post ongoing updates on the SPP website.

The commission in September ordered the compliance filing for the grid operator's proposal to unwind credit payment obligations assessed under Z2 for transmission service taken from 2008 to 2016. The commission determined that SPP lacked specifics in its proposed plan (ER16-1341). (See FERC Requires Additional Z2 Filing from SPP.)

Under Attachment Z2, SPP compensates upgrade sponsors who pay for upgrades that are subsequently used by transmission customers. FERC issued a remand order that called for the refund of Z2 amounts settled and invoiced for operating periods in 2008-2015.

Full refund invoices for the 2008-2015 period will go out within the first two months after FERC's final order. A resettlement invoice will follow in about two years for the operating dates from September 2015 to January 2020. It will take several years after that to run additional resettlements in the current settlement system until SPP catches up.

Staff told FERC in September 2024 that at least $657.8 million is directly affected by the commission's refund directive and that it grows by $3 million to $4 million each month.

"Every month that we can't make our repayment is more interest that our members are paying and we have no return on," Western Farmers Electric Cooperative's Matt Caves said.

SPP has assembled more than a dozen executives and staffers to handle the process. As Suskie said, alluding to the Blues Brothers in their eponymous 1980 flick, "We're getting the band back together.

"It took us eight years to put Z2 together. Now, we've got to unwind it and put it back together," he added.

Staff are planning a formal kickoff for the effort in January 2026. They expect the effort to take about four years.

West Gets Stakeholder Group Seats

MOPC endorsed expanding six working groups to add members from the RTO's expansion into the Western Interconnection. The vote slipped past MOPC's two-thirds threshold for approval at 67.24%.

If the measure is approved by the Corporate Governance Committee (CGC) and then the board in November, the Market, Economic Studies, Operating Reliability and Supply Adequacy working groups would get four more seats, and the Members Committee, Strategic Planning Committee and Resource and Energy Adequacy Leadership (REAL) Team will each pick up two seats. The Regional Tariff and Transmission working groups will add TOs and transmission users according to their charters.


Steve Gaw, Advanced Power Alliance, makes his point as Brad Hans, MEAN, listens. | © RTO Insider

The RTO expansion will add seven Western entities, including several that are already members in SPP's Eastern Interconnection footprint. Members with load in the East won't be counted toward the new seats, staff said.

An earlier attempt to amend the motion from the floor and limit Western representatives to two seats apiece in the working groups failed, garnering just under 50% approval. Several members pushed back against taking up the issue, saying it belongs in the CGC.

"Vacancies on working groups don't come up terribly often, so to get entities on board and through this process is a starting point," said Brad Hans, with the Municipal Energy Agency of Nebraska. The agency will be active in both interconnections.

"It's a good integration thing," he said. "There are a lot of differences in the West with us working on both sides, where you need that expertise in the West to bring to the conversations when there are things that may affect both sides."

SPP's Steven Johnson, senior director of markets administration, said the RTO expansion project remains on schedule, having moved from red to yellow status at the end of September. Bid-to-bill member testing, a key milestone, began Sept. 2 and is ongoing, he said.

MMU: Topology Optimization Concerns

Stakeholders endorsed the Market Working Group's expansion of the economic topology optimization process that enables market participants to submit requests for SPP to screen, evaluate and, if they pass both economic and reliability criteria, coordinate with transmission operators for implementation.

The change sets submission limits to one per participant/month, six studies per month and up to three active implementations.

The Market Monitoring Unit said it supports the concept but had "serious concerns" with allowing the requests to come from market participants. Carrie Bivens, the MMU's vice president, said MISO tried a similar process but it "reported very low success rates" with being able to accept the proposals.

"Not only could it result in suboptimal results, but it's also a clear fairness issue," she said. "We believe the RTO should be doing this optimization rather than taking it through stakeholders and through market participant requests. Just from a practical standpoint, it could be a real waste; an inefficient use of SPPs time."

The measure passed with 90.8% approval.

The committee also endorsed two recommended tariff changes from working groups:

- *RR719*, from the Cost Allocation Working Group, which would base-plan fund network upgrades for network resource interconnection service (NRIS). The proposed change aligns cost allocation for deliverability by allowing the delivery portion of NRIS before the transition to the Consolidated Planning Process to also be eligible for base-plan funding. MOPC gave it 88.2% approval.
- *RR697*, from the MWG, codifying a policy approved by the Regional State Committee to give market participants more opportunities to receive long-term congestion rights (LTCRs). Eligible participants will be able to nominate up to 50% of each path, with all current awarded LTCR paths over 50% grandfathered. The awarded LTCRs can be held for five years. RR697 passed with 72.6% approval.

Ross Exits as MWG Chair

MOPC members honored American Electric Power's Richard Ross with a round of applause as he delivered the MWG's final proposed tariff changes under his chairmanship.

Ross has served as chair of the MWG, one of the more influential stakeholder groups, since 2004. That was the year FERC *designated SPP as an RTO*. Recent governance changes have placed term limits on working groups' leadership positions.

"I've been involved in SPP things for issues from 12 [to] 15 years, and you have been a longstanding chair of the Market Working Group. A lot has passed under your purview," Omaha Public Power District's Joe Lang said.

SPP's Carrie Simpson, who once served as the MWG's staff secretary, said she has used Ross' chairmanship as an example to follow in designing the stakeholder structure of Markets+ in the Western Interconnection.

AEP's Richard Ross acknowledges applause for his 24 years as the Market Working Group's chair. | *© RTO Insider*

"I know you've seen a lot of staff come through and a lot of members," she told Ross. "As we were setting up working groups in the West, we would say, 'Watch Richard Ross. The MWG chair is a great standard for how to run a meeting.'

"But you've had 20 years of practice," Simpson cracked.

"I did have that," Ross admitted.

Ross will remain a member of the MWG.

20 Tariff Changes Approved

MOPC's consent agenda, unanimously approved, included:

- the Project Cost Working Group's recommendation to accept all 10 transmission projects with in-service delays exceeding the first reported in-service date by more than 90 calendar days be accepted as reasonable;
- the PCWG's endorsement of a 31% increase in Nebraska Public Power District's 345-kV Gentleman-Cherry County-Holt County project, from $510.71 million to $669.97 million;
- the 2026 ITP-CPP transmission assessment's revised scope to add the Expedited Resource Adequacy Study's stability needs;
- the TWG's endorsement of OPPD's sponsored upgrade study for Sarpy County uprates; and
- the annual *violation relaxation limit analysis report*.

The agenda also had 20 proposed tariff changes that, if approved by the board, would:

- *RR655*: establish outage submission requirements in SPP's governing documents, including definitions, data standards, timelines and rules for submission, extension and updates. The change would require market participants to provide accurate, timely outage and capability information, with the transmission provider reviewing and potentially denying noncompliant submissions.
- *RR670*: clarify that a mitigated offer is defined as equality along with its allowable subcomponents and must be interpreted as such when calculated and submitted by market participants.
- *RR682*: add transparency to the competitive transmission process' TO selection process by requiring the industry expert panel to respond to questions from the board or submitted by stakeholders.

- *RR686*: clarify the difference between ramped and stepped setpoints with consolidated examples, removing outdated quick-start terminology for improved clarity and consistency.
- *RR690*: define the tariff-required harm test to reallocate at-risk financial security funds during the generation-interconnection study process to mitigate harm done by terminating generator interconnection agreements.
- *RR695*: establish thresholds for mitigating offers below $25/MWh, aligning them with correct mitigation practices.
- *RR700*: raise the notification-to-construct (NTC) with conditions and the applicable project threshold limit from $20 million to $150 million.
- *RR705*: update the Generator Interconnection Manual (*BP7250*) with the Joint Targeted Interconnection Queue's tariff language.
- *RR706*: clarify that a federal service exemption transfer point is a qualifying source for candidate LTCRs/auction revenue rights (ARRs) by adding the transfer point to the list of qualifying sources for candidate LTCRs/ARRs.
- *RR707*: revise the conventional resource performance-based accreditation business practice without changing FERC's foundational policy.
- *RR708*: ensure the detailed project proposal window for transmission planning is not unnecessarily extended if additional needs are identified after the needs assessment's posting.
- *RR709*: ensure the annual index of grandfathered agreements is accurate.
- *RR710*: automatically suspend Attachment AQ upgrade projects with NTCs if the large load is not submitted within 180 days of board approval. SPP would then conduct an out-of-cycle re-evaluation and bring it to the board for its consideration.
- *RR711*: formalize the outage-coordination methodology as a business practice and incorporate it into the revision request routing criteria, requiring applicable working group approval for future changes.
- *RR712*: increase the financial commitment window for SPP's NTC issuances from four years to five years.
- *RR713*: add language to the tariff including Stegall DC tie equipment in the incremental market efficiency use (IMEU) framework, ensuring transparency, stakeholder review and clarification that replacement costs are not tied to IMEU.
- *RR715*: outline the study requirements used in the quarterly analysis to determine the maximum amount of capacity available for generators under the limed operation condition until network upgrades come online.
- *RR716*: clean up items related to the RTO expansion's DC ties, including calculations using their capability for cost allocation and DC tie inputs in market cases and the reliability unit commitment process.
- *RR717*: clarify tariff and protocol language applying the "tank test" to day-ahead and RUC make-whole payments, explicitly excluding its use for multiday reliability assessments and local reliability events.
- *RR721*: update SPP's business practices to account for changes required by the RTO's expansion in the West. ■

GE Vernova Moves to Expand Grid Equipment Segment

Acquisition of Prolec Boosts Company's Electrification Business

By John Cropley

GE Vernova is moving to expand the reach of its fastest-growing business segment, Electrification, by acquiring full ownership of grid equipment supplier Prolec GE.

The company and its corporate predecessor, General Electric, have held a 50% stake in the transformer manufacturer through a joint venture with Mexico-based Xignux since 1995. In their *Oct. 21 announcement*, the partners said the $5.3 billion deal is expected to close in mid-2026.

GE Vernova CEO Scott Strazik led off the *third-quarter earnings call* Oct. 22 with discussion of the acquisition, which he said will provide multiple benefits for the company amid surging U.S. power demand.

Full ownership will remove contractual constraints, allow better control over pricing and strategy, provide a better customer experience and pave the way for integrated solutions, Strazik said. It also provides one more entry point to the data center market.

"We have talked recently about our expected higher R&D next year to develop and deliver more product to data centers, and going beyond the transmission substations we provide today," Strazik said. "Prolec will help deliver an even more robust range of product offerings."

Prolec is expected to produce an EBITDA margin of approximately 25% in 2025, and its 2028 revenue is projected to be 40% higher than 2025.

GE Vernova reported *third-quarter 2025 income* of $453 million ($1.64/share) on $10 billion in revenue.

Of the three business segments:

- Power had the largest numbers: $7.8 billion in orders, $4.8 billion in revenue and $84.1 billion backlog.
- Electrification had the strongest growth, with an EBITDA margin of 15.1% compared with 10.4% in the same quarter of 2024.
- Wind brought up the rear, with improved profitability and decreased offshore losses, but a negative EBITDA of $61 million.

GE Vernova will acquire full ownership of grid equipment supplier Prolec GE, its joint venture with Xignux. | *Xignux*

Strazik said market interest in gas power continues unabated: GE Vernova signed 12 GW of new contracts in the third quarter after signing 9 GW in the second quarter. The backlog of gas turbine orders grew from 29 GW to 33 GW, and manufacturing slot reservations increased from 25 to 29.

"We now expect to approach 70 GW of contractual gas power commitments by the end of '25 with significant momentum into '26," he said.

Why This Matters

The deal will expand GE Vernova's portfolio as it pursues its share of the growing U.S. power market.

An analyst asked about indications that demand for new turbines may be peaking and that asking prices are starting to be more negotiable.

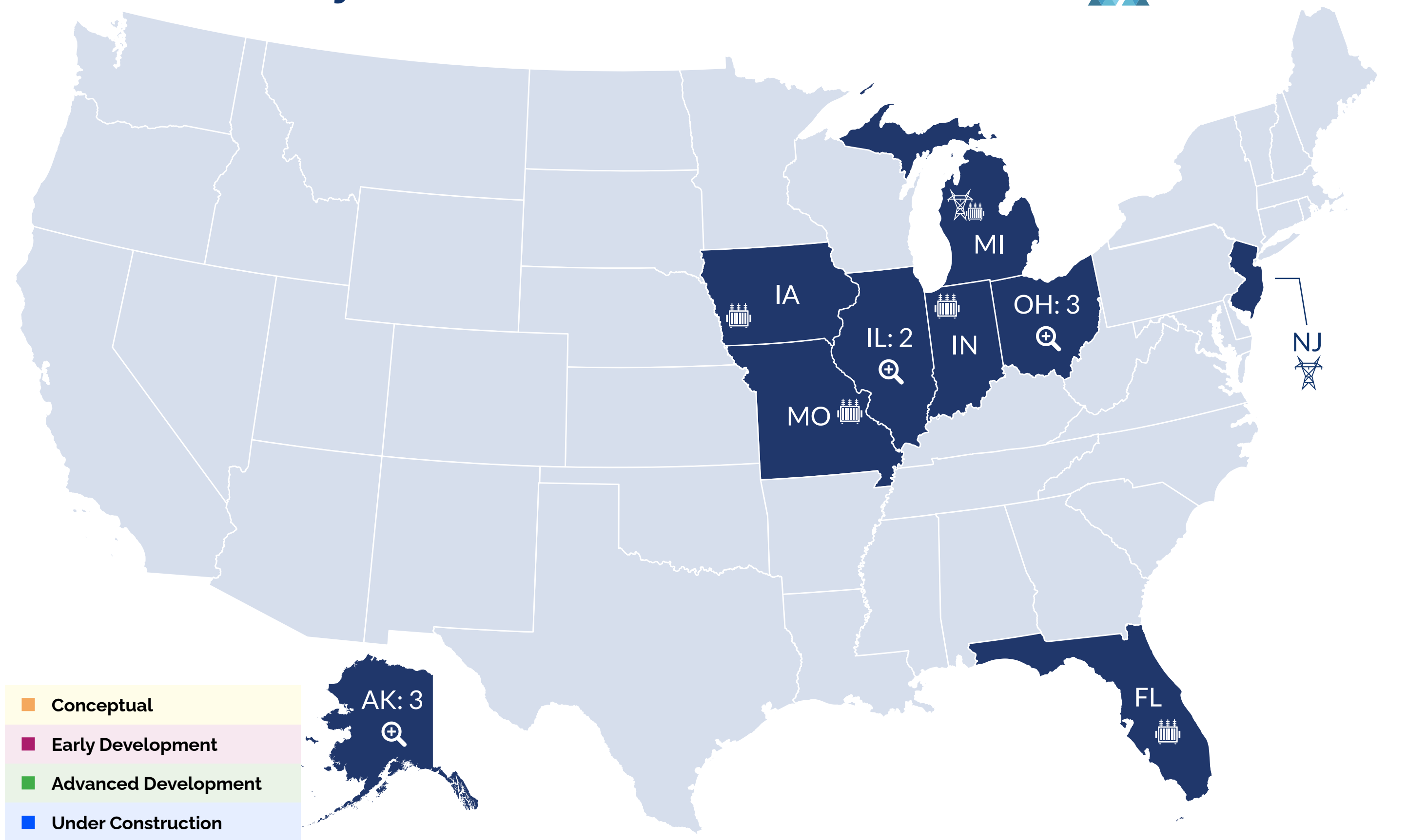
Strazik said the company is not softening on its asking price, although its order book for any given quarter may not be an accurate barometer.

"In the third quarter, as an example, we had substantially more smaller gas turbines, more aeroderivatives, that are a higher price per megawatt than the baseload units," Strazik said. "In totality, we continue to see price accelerating in gas," he said, pointing to the higher prices and better profit margins for the slot reservations that he expects to progress to contracted orders in the next 12 months.

The larger gas turbines are much more economically efficient, he said, but there is a near-term surge in demand that the smaller units will meet. He predicted the aeroderivative and other small gas-fired generators would bridge the need for power until heavy-duty units are available, then convert to backup roles. ■

Generation Projects Added in the Past Week

YES ENERGY



New Line | New Substation | New Line / New Substation | Line Upgrade | Substation Upgrade

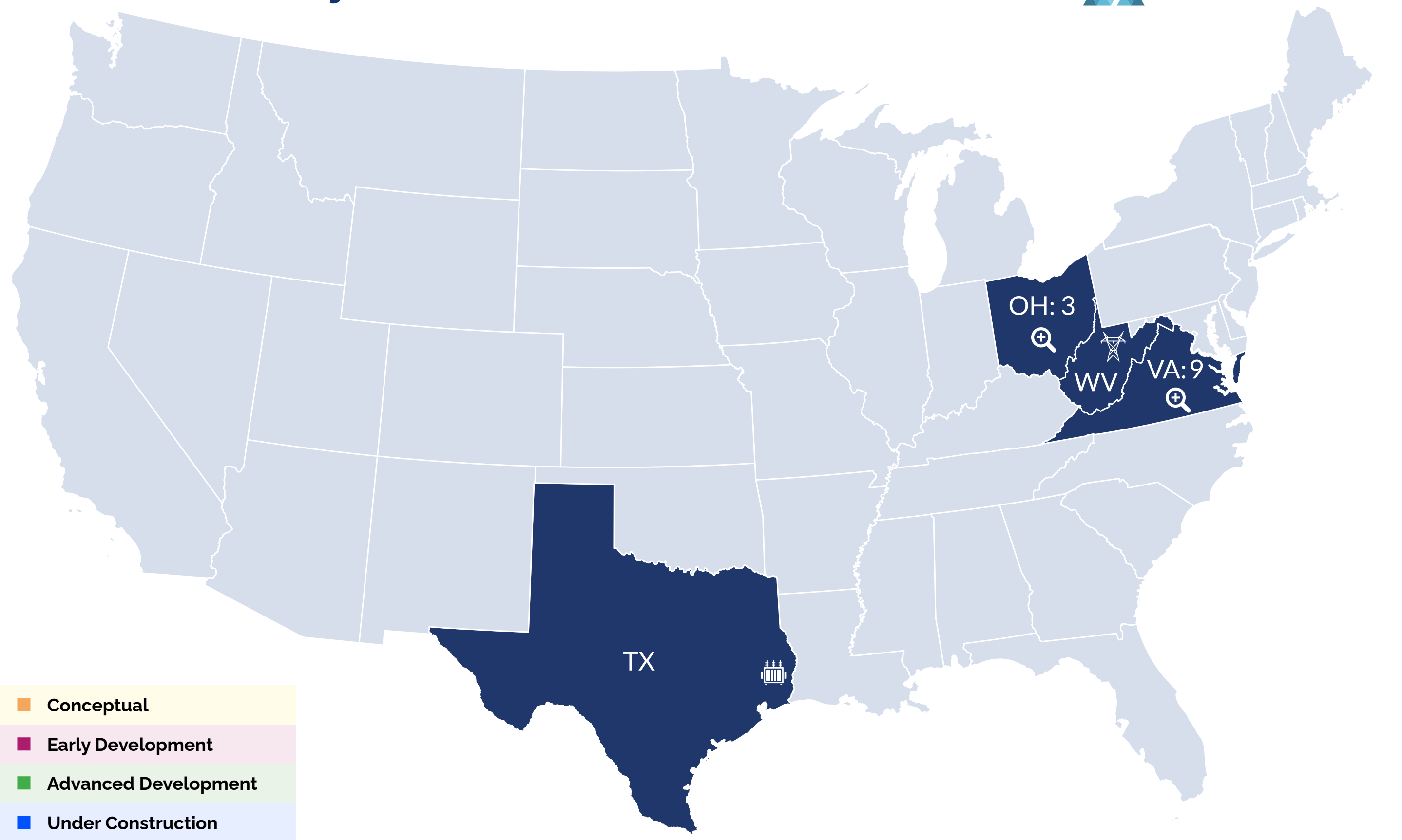
Data from Yes Energy

	Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
	Soldonta - Bernice New Line	Alaska Energy Authority (AEA)	Alaska Energy Authority (AEA)	230	2035	AK / AK
	Intertie Connector	Alaska Energy Authority (AEA)	Alaska Energy Authority (AEA)	230	2035	AK / AK
	Beluga - Healy New Intertie	Alaska Energy Authority (AEA)	Alaska Energy Authority (AEA)	230	2035	AK / AK
	Van Meter New Substation	Kissimmee FL, City of	Kissimmee Utility Authority (KUA)	69	2026	FL
	East Kanesville New Substation	Berkshire Hathaway Energy	MidAmerican Energy Company	161	2029	IA
	Cottonwood Creek Tie-In (L96407)	Exelon Corporation	Commonwealth Edison	345	2029	IL / IL
	Broomstick Solar Network Upgrade	Exelon Corporation	Commonwealth Edison	345	2026	IL / IL
	AE2-045 Switching Station New	American Electric Power	Indiana Michigan Power	345	2027	IN
	Lake Trout Solar Network Upgrades	American Electric Power	Indiana Michigan Power	345	2028	MI
	Hayford New Substation (Sioux-Belleau)	Ameren	Ameren Missouri	345	2027	MO
	AG1-254 Network Upgrade	Exelon Corporation	Atlantic City Electric Company (AEC, AECO)	69	2029	NJ
	New Lebanon Tap Cut-In Network Upgrade (Hutchings-Crown)	AES Corp.	AES Ohio (formerly Dayton Power and Light)	69	2028	OH
	Carnation Solar Loop-In (AF2-371)	American Electric Power	American Electric Power Ohio	138	2028	OH
	Beatty - Greenek New Tap	American Electric Power	American Electric Power Ohio	345	2026	OH

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

Generation Projects Added in the Past Week

YES ENERGY



New Line | New Substation | New Line / New Substation | Line Upgrade | Substation Upgrade

Data from Yes Energy

	Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2
	Philo - Newcomerstown 138 kV New Line	American Electric Power	American Electric Power Ohio	138	2030	OH / OH
	Mechanicsburg Substation Cut-In (Urbana - Darby)	AES Corp.	AES Ohio (formerly Dayton Power and Light)	138	2029	OH
	Galion - South Berwick New Tap	American Electric Power	American Electric Power Ohio	345	2026	OH / OH
	Fish Lake New Substation	Entergy	Entergy Texas (ETI)	138	2027	TX
	AE1-173 Network Upgrade	Dominion Energy	Dominion Virginia Power	500	2029	VA
	AF2-304 Network Upgrade (Wards Creek - Surry)	Dominion Energy	Dominion Virginia Power	230	2028	VA
	Pegasus - Hornbaker Route 1 New Line (Line 2187 and Line 2424)	Dominion Energy	Dominion Virginia Power	230	2029	VA
	Hecate Energy Pulaski Network Upgrade (Glen Lyn - Claytor)	American Electric Power	Appalachian Power	138	2028	VA
	Gibson Solar I Network Upgrade	Dominion Energy	Dominion Virginia Power	230	2026	VA
	Bakers Pond Solar Network Upgrade	Dominion Energy	Dominion Virginia Power	115	2025	VA
	Wellington - Pegasus Route 1 New Line (Line 2325 and Line 2423)	Dominion Energy	Dominion Virginia Power	230	2029	VA / VA
	Unnamed New Switching Station (Claytor - Glen Lyn #1 Circuit)	American Electric Power	Appalachian Power	138	2028	VA / VA
	New Substation (Unnamed) (Looney Creek Substation Upgrade)	American Electric Power	Appalachian Power	69	2027	VA / VA
	Albright - Cross School New Tap	FirstEnergy Corp.	Allegheny Energy	138	2028	WV

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

Company Briefs

BP-JERA JV Pulls Plug on Beacon Wind

JERA Nex BP, the joint venture company formed between BP and JERA, last week announced it will not proceed with the development of its Beacon Wind project off the coast of Massachusetts.

"Unfortunately, in the present environment, we see no viable path to the development of our Beacon wind project and have concluded that we cannot continue our investment in the market," the company said.

The joint venture company was announced last year and launched in August 2025. The lease for Beacon Wind was originally awarded in December 2018.

More: *The Maritime Executive*

Google Backs Gas Plant with CCS for Data Centers

Google last week announced it has entered into the first corporate agreement to buy electricity from a power plant using carbon capture and storage in a deal to help fuel its data centers in the Midwest.

Google's power offtake agreement involves a 400-MW power plant in Illinois, which will be developed by Low Carbon Infrastructure. It is expected to produce power using carbon capture, which involves trapping about 90% of CO_2 emissions and injecting them underground, in the early 2030s.

Google did not disclose the financial terms of the deal.

More: *Reuters*

Xcel Names Shea President of Midwest

Xcel Energy last week named Bria Shea as president across its Minnesota, North and South Dakota region, effective immediately.

Since joining Xcel in 2008, Shea has held several leadership roles on the regulatory team. She most recently was regional vice president of planning and policy, leading government affairs and regulatory strategy for resource, transmission and distribution planning for the company's energy systems across the Upper Midwest.

Shea succeeds Ryan Long, who was named executive vice president, chief legal and compliance officer earlier this year.

More: *West Central Tribune*

Rivian to Lay off Workers

Rivian is laying off roughly 4.5% of its workforce as the electric vehicle maker faces growing market challenges, according to a note sent to employees.

The note did not specify how many employees would be laid off, but initial reports said the layoffs would affect more than 600 workers.

Rivian CEO RJ Scaringe said the cuts largely involved restructurings of its marketing, vehicle operations and sales/delivery and mobile operations teams.

More: *CNBC*

Vistra Completes Acquisition of 7 Natural Gas Plants

Vistra last week announced it has completed the acquisition of seven natural gas plants totaling 2,600 MW from Lotus Infrastructure Partners.

With the acquisitions, Vistra geographically expands its generation portfolio, adding assets in PJM, New England, New York and California.

More: *Vistra*

Federal Briefs

NNSA Puts 1,400 Nuclear Staffers on Furlough

The National Nuclear Security Administration (NNSA) last week furloughed more than three-quarters of its staff as the government nears its fourth week of a shutdown.

A Department of Energy spokesperson said 1,400 NNSA employees were furloughed on Oct. 20, leaving fewer than 400 working at the agency. It is the first time in NNSA's 25-year history that the agency has furloughed employees during a shutdown.

More: *The Hill*

2025 U.S. Climate Disasters Costliest Ever on Record

The first half of 2025 was the costliest on record for major disasters in the U.S., according to the Climate Central group.

In the first six months of this year, 14 separate weather-related disasters have totaled at least $1 billion in damage. In total, the events cost $101 billion in damages — a number higher than any other first half of a year since records began in 1980.

The bulk of the damage was caused by the Los Angeles wildfires in January. At $61 billion in damages, the fires are one of the most expensive climate-related disasters on record in the U.S., and the only top-10 event that is not a hurricane.

More: *The Guardian*

BLM Geothermal Lease Sale Nets $9M

A geothermal lease by the Bureau of Land Management in Nevada received a total of $9.44 million in bids.

Out of 113 parcels offered, 86 parcels received bids.

About a year ago, a similar geothermal lease in Nevada received a total of $7.86 million in bids for 64 out of 66 parcels.

More: *Bureau of Land Management*

State Briefs

CONNECTICUT

Gov. Lamont Names 4 to PURA Board

Gov. **Ned Lamont** last week appointed four new members to the Public Utilities Regulatory Authority.

Lamont named consumer advocacy attorney Thomas Wiehl as the new chair. Wiehl will replace Marissa Gillett, who resigned from the role earlier this month. Joining Wiehl will be former state Rep. Holly Cheeseman, energy policy professor Janice Beecher and investor Everett Smith.

Each of the members will serve in an interim capacity until their appointments are confirmed during the next legislative session.

More: *CT Mirror*

IDAHO

Idaho Power Files for Rate Decrease

Idaho Power on Oct. 9 filed for a nearly 1% rate decrease with the Public Utility Commission.

The company told the PUC that the closure of the second unit at the North Valmy Generating Station, a 522-MW coal plant, had removed costs. It also said the demolition of a second, already-closed coal plant had eliminated regulatory liability costs.

Combined with a recent increase in rates to recover the cost of upgrades to protect against wildfires, the utility said it needed $588,295 less in net revenue, which equated to "an overall decrease of 0.90%" in necessary rates.

More: *Latitude Media*

INDIANA

22 Applicants to be Interviewed for URC Openings

The Utility Regulatory Commission Nominating Committee last week announced that out of the 47 applications it has reviewed, 22 will be interviewed for three openings on the commission.

The finalists include 12 Republicans and 10 Democrats. According to state code, the commission can't have more than three members from the same party.

More: *Indiana Capital Chronicle*

MICHIGAN

Uranium Fuel Arrives at Palisades Nuclear Plant Ahead of Restart

Holtec International last week confirmed that 68 fresh fuel assemblies were delivered to the 800-MW Palisades nuclear plant and placed in the spent fuel pool for inspection and storage until workers begin loading them into the reactor core.

The delivery signals that the once-shuttered facility is on track to be operational by the end of this year, according to the company. The new fuel assemblies won't be enough to completely power the facility. In addition, 136 partially used fuel assemblies will be returned to the reactor core to reach the optimal mix for restart.

If successful, Palisades is poised to become the first U.S. nuclear power plant to restart after entering decommissioning.

More: *MLive*

NEVADA

NV Energy Changes Violate State Law, Experts Say

The Attorney General's Bureau of Consumer Protection (BCP) contends rate changes approved by the Public Utilities Commission as part of a $119 million rate hike for NV Energy are prohibited by state law and are one of several parties asking the PUC to reconsider its approval.

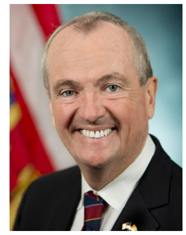
Last month, the PUC approved a peak demand charge that allows NV Energy to impose a higher rate for the 15-minute period of the day with the most energy use. State law, the BCP argued in its petition for reconsideration, prohibits the PUC from approving a rate that "requires a residential customer to purchase electric service at a rate which is based on the time of day, day of the week or time of year" unless the customer chooses to do so.

A hearing is set for Nov. 18.

More: *Nevada Current*

NEW JERSEY

Gov. Murphy Seeks Changes to Data Center Bill



Gov. **Phil Murphy** last week conditionally vetoed legislation that would require data centers to report their water and electricity use, asking lawmakers to add provisions directing the Board of Public Utilities to weigh whether the data centers' power and cooling demands are unduly burdening other ratepayers.

The redrafted bill would require the BPU to ask whether ratepayers unreasonably subsidize data centers, examine whether they are funding infrastructure that solely or mostly serves data centers, and estimate how much of utility bills are attributable to data centers' demands as part of a study called for under existing law. As originally drafted, data center operators would have been required to report their utility use within six months of the bill's signing. The governor's conditional veto would extend that timeline, requiring those reports be filed by January 2027.

Assembly Republicans opposed the original bill, but it won bipartisan support in the Senate.

More: *New Jersey Monitor*

PENNSYLVANIA

PUC to Investigate PPL's Proposed $356M Rate Increase

The Public Utility Commission last week unanimously voted to suspend and investigate a proposed rate increase by PPL Electric Utilities.

The proposed rate increase, which was filed on Sept. 30, seeks an annual increase in revenues of $356.3 million (33.4%). As of Oct. 23, the request is suspended for up to seven months from the proposed effective date of Dec. 1, and will be assigned to the PUC's Office of Administrative Law Judge for investigation and recommended decisions.

A final decision on the request is due by July 1, 2026.

More: *WGAL*