ISSN 2377-8016 : Volume 2025/Issue 39 ▪ September 30, 2025

YES ENERGY

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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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ISO-NE

Escalating Conflict with Utilities Leads to Resignation of Top Conn. Regulator

Connecticut PURA

The forthcoming resignation of Connecticut Public Utilities Regulatory Authority Chair Marissa Gillett has created high-stakes questions around the state's adoption of a comprehensive performance-based regulation framework, with three key votes set to occur just two days before she is scheduled to step down.

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CAISO/WEST

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In this week's issue

Pragmatism, Adaptation and a Touch of Wishful Thinking at Climate Week NYC

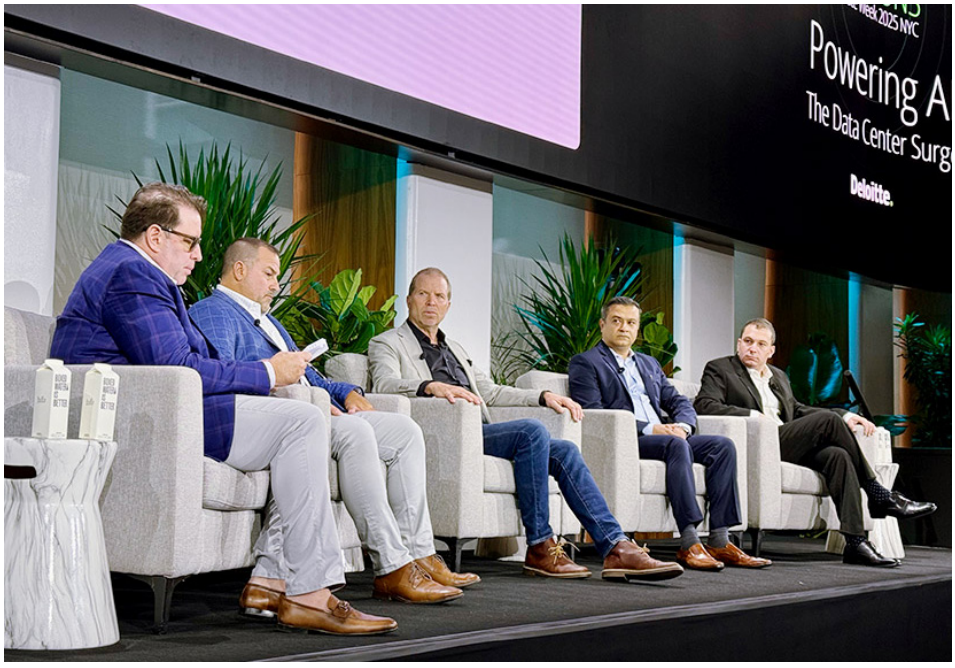
By Dej Knuckey

Dej Knuckey

New York, frenetic at the best of times, bordered on frantic when Climate Week coincided with the U.N. General Assembly meeting last week.

While the U.N. addressed climate in its hushed halls, experts and pundits at hundreds of Climate Week events scattered across dozens of locations analyzed every aspect of it. Like a subway running beneath this melee of meetings, there were common themes that connected the many panels and events I attended: Old goals were quietly dropped, new challenges accepted and an AI-led future imagined.

Note: Many panels were under *the Chatham House Rule* or on background only, so some ideas and quotes below are not attributed. Just know that all the speakers had lengthy titles, impressive biographies and well-known employers.



From left: Martin Stansbury, Deloitte; Nate Florio, Deloitte Christopher Wellise, Equinix; Ameya Soparkar, Arup; Arod Balissa, Deloitte Catalyst | *© RTO Insider*

Hello ChatGPT, Goodbye 1.5 Degrees

This was my first climate event where there was little mention of the Paris Accord goal of limiting the global average temperature increase to 1.5 degrees Celsius above pre-industrial levels. "One-point-five" used to be a term so common it was rarely explained. IYKYK — and Climate Week attendees *know*. This year, the few times it was used, it was in a casual aside about the target there was no chance of meeting, or the limit that may already have been exceeded.

Only two years ago, many in the climate space called for radical emissions cuts to reach the goal. Today, the consensus among the business end of the climate community — asset managers, developers, business leaders and consulting giants — is that the goal is about to be in our rearview mirror, courtesy of the rise of AI. U.S. political headwinds and two more years of too little action? Just additional speed bumps on the way.

"The net-zero, 1.5-degree scenario is now a mathematical exercise. We could not get there from a policy perspective," the leader of an energy analytics organization said. "We retain it because it's important to look at it, but it's not something that we were able to achieve other than [through] a mathematical formula."

Move over Mitigation, the Age of Adaptation has Arrived

The other common climate term noticeably absent was mitigation. It used to be that mitigation was king and adaptation was a quitter's word, one for those who didn't believe we had the skills and will to pull humankind out of its climate nosedive.

Today, adaptation is a necessary evil needed to cope with the damage being done to the planet. It is not that everyone won't do their best to mitigate, but it's no longer enough.

"I'd like to avoid being seen as the pessimist in the room," an in-house climate scientist at an analytics firm said. "We can turn this problem around and talk about the benefits of adaptation, or the benefit-to-cost ratio for adaptation. A *recent study by JP Morgan* has calculated that the reduced or avoided risk is between $2 and $43 per dollar invested in adaptation. It's a huge opportunity."

If you are building infrastructure today, the head of the infrastructure of one of the world's largest asset managers said, you might as well make it strong enough to withstand a future riddled with climate disasters. In the emerging markets, for example, he said it was "significantly cheaper to build something … to an international standard that will withstand the expected impacts of climate change that will come over the next couple of decades. We build to a certain standard that we hope we don't need, but hurricanes have become stronger, fire risk is greater."

Electrical transmission and distribution assets should be built with community vulnerability in mind, he said, so that they not only could provide service during extreme climate events but also would not cause those disasters.

Business discussions about a post-one-point-five, adaptation-focused world were positioned as "pragmatic." The word was used with a touch of guilt: not that they wanted to go gentle into that good night, but it seemed futile to rage, rage

against the dying of the light. In an unwinnable war, pragmatists should focus on minimizing the damage … and perhaps even profiting from hardening the infrastructure ahead of the impending crises.

AI: Energy's Frenemy

The rise of AI and the massive data centers that power it are the culprits behind the surrender of the target. But AI is seen as both a power-hungry enemy and an efficiency friend.

At Deloitte's three-day Climate Week Horizons conference, data centers were cited as driving demand for electricity.

"There is no doubt that AI is creating the single-largest [rise in] energy demand in decades," said Martin Stansbury, principal and U.S. power, utilities and renewables risk and financial advisory leader at Deloitte. "And the real question is: Can we build it fast enough? Can we build it clean enough, and can it be resilient enough for the market?"

"By our analysis, we see about a five times growth in data center power demand by 2035," Kate Hardin, executive director at Energy, Resources and Industrials Research, said at the Deloitte event. She said industrial electrification was the other major trend driving demand.

On the flip side, AI was cited as the potential hero for optimizing everything from buildings to ports … as well as the grid itself. While many speakers worried about how quickly generation could be built to service AI data centers or how the related demands on water supply would be met, others believed AI would unlock more energy savings than the data centers themselves would consume. Ultimately, AI will be a self-correcting challenge.

Speaking at *Axios House*, Tom Steyer, the billionaire co-executive chair of *Galvanize Climate Solutions* and former Democratic presidential candidate, talked about AI's ability to make the grid substantially more efficient.

"If you look at renewables in this country, the big pain points are permitting and access to the grid," he said, citing a discussion with a Californian investor-owned utility who told him it took 12 years to permit and build a new distribution line.

"The grid in California is 32% efficient. The grid in the United States is 42% efficient. We have the ability now, using real-time information and AI protocols, to completely change that number. If we can go from 32 to 64 [percent efficiency], we've rebuilt the grid," Steyer said.

The chair of a major AI developer speaking at a different event had a similarly optimistic take: "The potential for efficiency and productivity of our existing infrastructure, using sensors, using artificial intelligence, is off the charts." For example, data and sensors enable better use of the existing grid through dynamic load ratings. "When cable lines are cooler, they can get more current through them. Imagine if we could predict the weather, that would predict the temperature of the line, that would allow us to optimize how much current we put through. These are the sorts of things that are possible."

AI's potential to optimize generation assets would create further potential for gains, he said, increasing the output from existing renewables capacity. "Imagine that: 10 to 20% for effectively nothing."

Efficiency Opportunities at Every Turn

It's not just generation and the grid that could be net beneficiaries of the AI revolution, some argued, but every industry that depends on electricity will gain efficiency.

For example, the real estate sector is unmatched when it comes to climate risks and opportunities, said Lauren Pesa, partner and U.S. real estate sustainability leader at Deloitte. "Real estate is the largest asset class in the world, representing two-thirds of global wealth. First Street Foundation projects up to $1.47 trillion in real estate value in the U.S. could be lost in the next 30 years due to climate risk."

Yet this massive asset class, a major consumer of the grid's electricity, is ripe with opportunities to be both more resilient and more efficient. AI and machine learning are key for moving digital building management systems from set-and-forget to active optimization, said Ben Dwyer, SVP global sales, Kode Labs, at the Deloitte event. "With the evolution of what's going on with automation, AI and [machine learning], you're essentially able to, over time, optimize the building to run as efficiently as possible."

While optimizing energy use will be important, smart buildings' ability to be more resilient during climate events such as Texas's large freeze and hurricanes will be critical, he said. "What smart buildings allow you to do is get ahead of these large events and ensure that your buildings are prepared for these things to happen, to ensure that not only the asset is protected, but the individuals that inhabit that building are protected," Dwyer said.

Ports are another example. Beth Rooney, port director at the Port Authority of New York and New Jersey, told a Deloitte panel on aging infrastructure that the port is on the cusp of a transformation.

"Between today and 2050 … we're going to double, if not triple, our cargo and passenger volume. I don't have land to expand to, so we have to take the land that we have and use it more efficiently and more productively. And that's where technology comes into play."

The Port Authority, whose infrastructure includes aviation infrastructure, tunnels, bridges and rail terminals, was using technology ranging from underwater drones to inspect pilings (fun fact: cleaner water is degrading the port's pilings faster) to GIS systems for more efficient maintenance. The ports were improving efficiency through four uses of technology, she said: predictive decision making, real-time risk management, enhanced visualization to see what's going on across 3000 acres, and hyper-connected logistics.

"We will not be able to handle the volume that is coming our way, not just in New York and New Jersey, but across the United States, if we don't change the way we do business," she said.

Wishful Thinking or Wondrous Optimization?

Overall, the consensus was that AI would save more energy than it consumed, leaving the world better off, even if there would be more fossil emissions to cope with during the transition. There was little talk about sequestration, despite the reluctant admission that fossil fuels would supply much of the AI-driven demand for now.

The head of an electrical components manufacturer warned against overestimating the amount of energy required by AI data centers. Last year, data centers consumed 1.3% of global electricity, so

doubling by 2030 and doubling again by 2035 would still leave it consuming only around 5% of the world's energy.

The question of how the markets would meet AI's power demand brought out the list of usual supply suspects, most notably nuclear, with small modular reactors commercially viable and available within the next five years, and every color of hydrogen. AI was still in its relative infancy, and potential efficiencies, ranging from improved cooling technologies to quantum computing, were expected to lower energy demand as the technology matured. Similarly, value could be extracted from the waste heat by industry or district heating systems, where they exist.

The Waiting Game

Behind the barricades around the United Nations, President Donald Trump was ripping into climate goals when he wasn't grumbling about *halted escalators and broken teleprompters*. However, business meetings mere blocks away seemed unconcerned that he labeled *climate change a "con job"* and wind and solar energy a "scam". If anything, his comments evoked smirks and assurances that project development operates on timescales that stretch well beyond any single administration.

An industry analyst said, "No matter what the president says, 91% of new additions to the grid in the United States this year have been batteries and renewable energy. So, if you don't think the transition is happening, you're burying your head in the sand."

And regardless of the president's opinion, fiduciary duty required investment advisers to manage the $16 trillion of U.S. employee retirement funds prudently, a lawyer said. "What does that mean with respect to climate change? When we have all the scientific data, [it] means you have to actually be mindful that these risks are going to have a financial impact on the portfolio," she said.

The dozens of speakers at events on and off the record agreed: Trump's comments at the U.N., and his administration's policies to date, were an annoyance, but not the driving factor for an industry that plans in decades. As the CEO of a major energy generation asset owner said, "There's nothing I could build today that [will] have a payback period during the Trump administration. There's nothing I could build today that's going to have a payback period in the next three administrations."

Practical Action, not Political Oration, is What Matters

Steyer said the administration's policies may slow the energy transition, but couldn't stop it: "Is [Trump] an existential threat to the world's ability to make this transition and to solve climate change? No. We're [the U.S.] 11% of emissions. Our emissions may go down slower, but … except for the year of COVID, we have never reduced emissions, and we're supposed to reduce emissions 40% this decade," Steyer said.

China's action would far outweigh any U.S. inaction. "In the first half of 2025, Chinese emissions went down 1%. China is a third of global emissions. Between 2018 and 2024, 95% of new fossil fuel demand came from China. If China's peaked, the world's peaked."

As Deloitte's principal and sustainability leader, Geoff Tuff, put it: "The headline is, no matter what we hear in different parts of the world, and no matter what reports you may see, the energy transition continues, and it will continue. And it's just the sheer reality. If you fast forward the clock 30 or 40 years, we will have a fundamentally different energy mix than we do today."

A Week to End All Climate Weeks

Like the COP28 I attended *in Dubai two years ago*, it was good to experience Climate Week NYC, if only so I could check it off my list and never go again. I'm too old to shout over a techno beat at a climate-startup-investor schmoozefest, too jaded to hear one more high-octane luxury brand's CSO congratulate their token coral-growing PR effort, and too tired to negotiate the subway sauna while running from one event to the next.

If I sound like a curmudgeon, I am. There's no simple way to sort the hundreds of events across dozens of locations, no consistent way to apply for them, and no unifying calendar and map to navigate your choices. And while the coinciding event at the U.N. brings climate experts in from the most impacted nations, it also drives hotel prices to astronomic heights, even by New York standards. Maybe they could build an AI agent to sort it all out.

But despite the stressors, this curmudgeon left happy to see that pragmatists are running the energy transition, tackling the big, hard challenges as they arise, undeterred by the political distractions happening a few blocks away. ■

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

From left: Lauren Pesa, Deloitte; Austin Koch, Hartford Insurance; Caitlyn Raines, Esri; Ben Dwyer, Kode Labs | © RTO Insider

The Craziness of Natural Gas Bans

By Kenneth W. Costello


Kenneth W. Costello

Political efforts to curtail gas supply and demand have met with limited success. Methane rules, drilling restrictions on public land and opposition to new pipelines have only incrementally slowed the growth of natural gas in the United States. But the obstinate *anti-fossil-fuel lobby* and its government allies want much more: moratoriums on new gas service and bans on natural gas usage and appliances.

Bans by municipal jurisdictions with (presumably) the legal authority to do so have been in the news for some time. The City of Berkeley *initiated municipal efforts* in July 2019 to electrify (especially via electric heat pumps and electric stoves) by prohibiting natural gas in new buildings. (Incidentally, the initiative was struck down by the courts.)

Since then, *various municipalities and states* have sought to restrict the use of gas in new buildings. For example, as of early 2024, dozens of local governments in seven states and the District of Columbia had imposed or passed ordinances for natural gas restrictions. New York became the first state to pass legislation imposing statewide natural gas restrictions affecting the state's local governments. Some cities have even considered banning or restricting natural gas appliances from existing homes and businesses, as well.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The primary purpose of these efforts is to mitigate climate change, however infinitesimal in the whole, by making buildings zero-carbon. A ban is much more extreme than just creating a tax to discourage consumption of a product or service. With a tax, the decision is left to consumers on how much of a product or service to purchase. A tax can counter a negative externality that is unaccounted for in the decisions of either suppliers or consumers, such as pollution or second-hand smoke; a gas ban obliterates consumer choice for meeting space and water heating needs, not to mention a flame for superior cooking and taste.

More fundamentally, such prohibition violates consumer freedom to purchase a wanted product or service like natural gas in place of an inferior one, namely electricity. Cheapness and quality are sacrificed on the altar of an environmental fixation that is debatable.

In economic terms, a gas ban fails miserably, with the benefits virtually zero and the costs potentially high. Thus, the benefit-cost (B-C) ratio is close to zero or the C-B ratio is infinite; or as public policy, a ban is off the charts as being exceptionally socially destructive.

Here is why: Less than 9% of *carbon-dioxide emissions* in the U.S. come from direct use of natural gas in homes and buildings. The U.S. emits about 15% of *world CO_2 emissions*. Thus, converting all buildings to all-electric, and assuming that all electricity is produced from "clean" sources (it is not), reduces worldwide emissions less than 1.5%, which according to climate models, would have less than a detectable effect on global climate, temperature, sea level or otherwise.

A ban can look good politically by giving the false impression that a severe problem is receiving immediate, absolute attention. And a ban certainly is less widespread than a carbon tax or a budget gap from new taxpayer subsidies. But at least these two approaches preserve consumers' option to choose their energy source, rather than preclude them from doing so with a ban.

The observation that a gas ban descends predominantly from a quasi-religious opposition to fossil fuels is credible given the lopsided cost-benefit calculus. Climate activists regard natural gas as competing with renewable energy in power generation and for electricity in end-use applications. Their position seems to be that "getting rid of the competitor" would make it easier to have more renewable energy and clean electricity.

It is only because of special interests that local and state governments would even consider prohibiting consumers from choosing natural gas as an energy source to meet their space, water heating and cooking needs. After all, in most parts of the country where gas is available, it is the most economic and desired source of energy.

Gas bans are little more than symbolic, reflecting a stance of "we have to do our part," or perhaps more accurately "whatever it takes to combat climate change," even if bans resoundingly fail a cost-benefit test.

Good public policy balances the economic and environmental consequences in enhancing the public interest. Because a gas ban — command-and-control policy at its worst — has virtually no effect on global climate and inevitably will increase cost and reduce quality for consumers, one would have to look hard to find a governmental action on energy that is so intrusive, imbalanced and detrimental to society's welfare.

One cannot avoid concluding the craziness of banning or even restricting a product like natural gas that has greatly benefited, and will continue to do so, both energy consumers and the economy. A ban on natural gas is throwing out the baby with the bathwater. ■

Kenneth W. Costello is a regulatory economist and independent consultant who resides in Santa Fe, N.M.

Your Opinion Matters

If you would like to submit an opinion piece related to energy policy or regulation, send it to:

forum@rtoinsider.com

Surplus Interconnection Can Maximize Capacity in ISO-NE

By Alex Lawton

Alex Lawton

We all appreciate the idea of squeezing out every last drop and making the most out of what you have. Our power grid should be no exception.

Yet in New England, rules governing how new resources connect to the regional grid limit full use of our system's potential. Precious "surplus" capacity can and should be leveraged to interconnect new, low-cost clean energy technologies to deliver more reliable, affordable power.

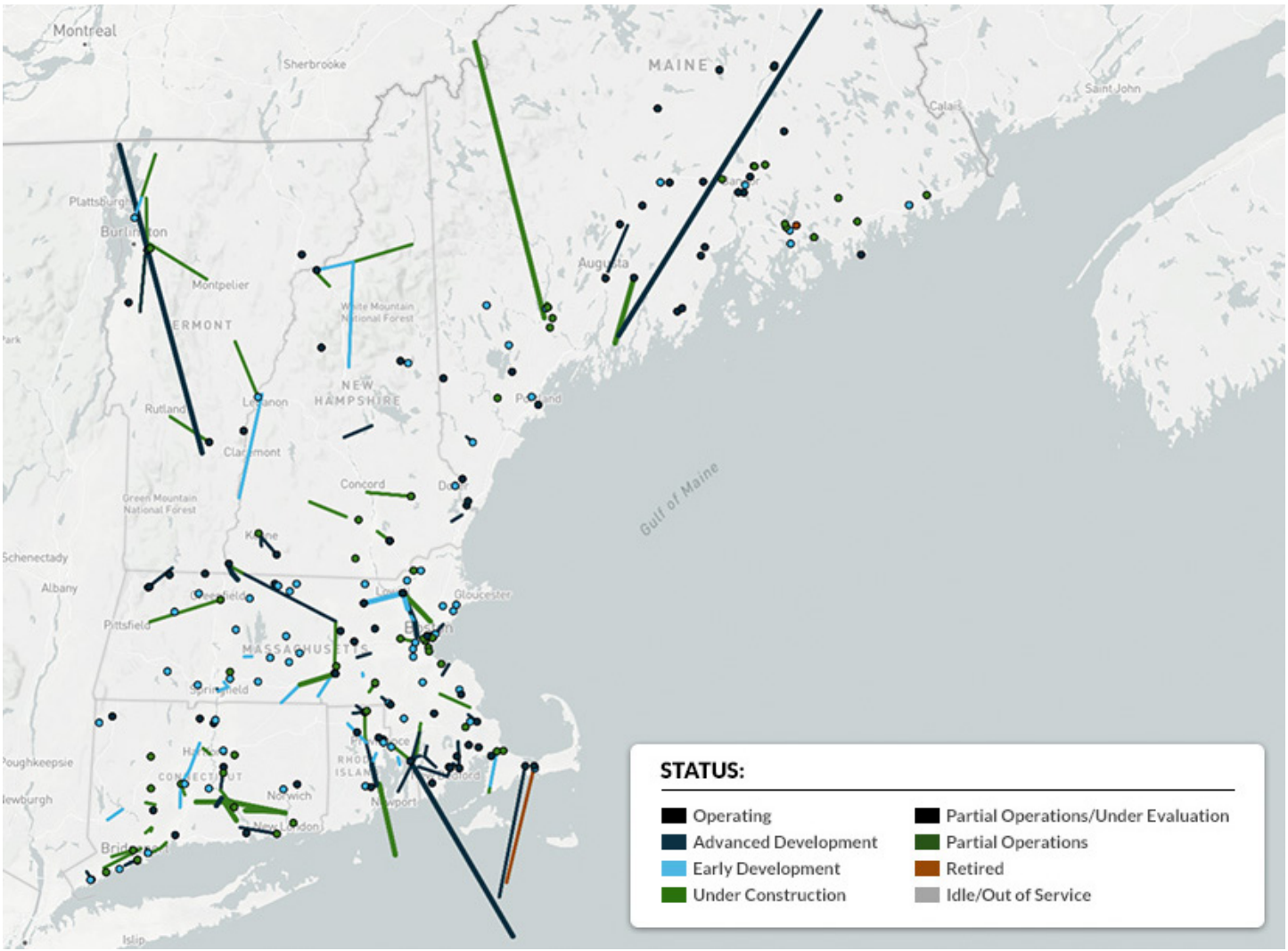
Capacity surplus interconnection service (SIS) is a solution hiding in plain sight that would allow the region to harness more capacity resources. At its core, reforming capacity SIS is about optimizing every megawatt of deliverability at each point of generator interconnection.

Throughout the system, there often is a discrepancy between how much capacity a generator is allowed to offer to the grid (i.e. an interconnection service limitation) versus how much they've committed to actually offer via the capacity market, i.e., the "capacity surplus."

Optimizing SIS could solve several problems for grid operators and policymakers amidst soaring electricity costs, *rising demand*, shifts in the resource mix and heightened emphasis on grid reliability.

A reformed capacity SIS option would allow new capacity resources to interconnect to the system in a fraction of the time and at much lower cost, which has significant benefits for consumer bills. Interconnection historically has been protracted, expensive and risky for new generation and storage projects, adding to the cost to develop projects that customers pay for through rates.

SIS circumvents these problems because it allows new capacity resources to bypass long and expensive reliability studies if they are willing to respect the existing capacity limitations at the point of interconnection. Respecting these limits also ensures these new resources avoid costly system upgrades.



ISO-NE transmission | *Yes Energy*

This more efficient path to connect to the grid will lower development costs and benefit ratepayers through bringing more capacity resources online faster to balance supply and demand. More capacity also supports resource adequacy and improves system reliability, keeping the lights on.

Other regions already have revitalized their capacity SIS rules to capitalize on these benefits. For instance, surplus reforms in MISO allow greater flexibility and speed for generators requesting surplus whilst ensuring that interconnection limitations are respected. As a result, MISO's surplus process has garnered *3.6 GW of surplus service requests* since 2021.

While capacity SIS technically is available in New England, outdated rules make it practically unusable for generators and prevent the region from harnessing capacity SIS opportunities. These barriers can be addressed with relatively modest revisions.

The first core issue is a restrictive condition that capacity resources must be "continuously available" on a permanent basis, which is impractical because it locks in a fixed quantity of surplus when in fact surplus availability constantly ebbs and flows based on performance audits as well as capacity accreditation. The fix: allow surplus resources the option for dynamic, periodic service.

Correcting capacity SIS deficiencies is timely specifically because of how it relates to capacity accreditation. ISO-NE is undertaking a major overhaul of its capacity market, including transitioning to a prompt and seasonal market and adopting a probabilistic approach to accredit resources based on their marginal value.

This new approach to capacity accreditation means accredited values may change significantly over time. As more renewables and advanced energy technologies enter the market, and as legacy plants receive derates for their imperfect performances during extreme weather events, accreditation values for many resources will drop. The key implication is that over time, the less capacity each generator can actually commit via their accredited limit, the more surplus headroom will open since the interconnection service limit — what generators are allowed to offer — stays the same. Ensuring capacity SIS rules are tied to accreditation reforms therefore will allow maximum use of surplus capacity on a continuous basis as accreditation values evolve.

The second core issue for surplus concerns what happens if an original generator retires, leaving just a surplus unit at the point of interconnection. Instead of allowing the surplus unit to maintain the interconnection limitation that applied to the original generator, which would enable the surplus unit to scale to that size, and avoid interconnection pitfalls, surplus units must go to the back of the line in the interconnection queue, with few exceptions.

Given the rising trend in generator retirements, a streamlined repowering process that allows surplus units to take over the interconnection rights in full and quickly begin injecting power into the grid could prove critical to maintaining electric system reliability.

In New England alone, the grid has the potential to unlock roughly *35 GW of new resources* via surplus service — an amount higher than our region's all-time peak demand. While that may be a high-end estimate, consider that according to the ISO's *2025 CELT Report*, there already is roughly 3 GW of capacity headroom on the system during winter time.

Once capacity accreditation reforms take effect in 2028, if results are similar to the *previous impact analysis*, approximately seven additional gigawatts suddenly could become available for the capacity commitment period in 2028.

Timing capacity SIS reforms now would dovetail with ongoing market reforms and address the urgent need for efficient new capacity resource entry. Recognizing this, industry stakeholders in New England have pushed capacity SIS reforms as a top priority for 2026.

This is a great opportunity for ISO-NE to follow through on the commitment it made in its FERC Order 2023 filing *transmittal letter*, promising to advance discussions on further interconnection reforms and measures that accelerate timelines.

The onus is on the ISO to undertake the initiative, gather stakeholder perspectives, and update its governing documents accordingly. If the ISO pursues these changes, New England's grid has the opportunity to squeeze every last drop of surplus capacity to make the most out of our existing grid. ■

— Alex Lawton is the wholesale markets director at Advanced Energy United.

Collaboration, Determination and Optionality are the Keys to Continued Market Expansion in the West

By Chris Robinson and Scott Simms

Chris Robinson

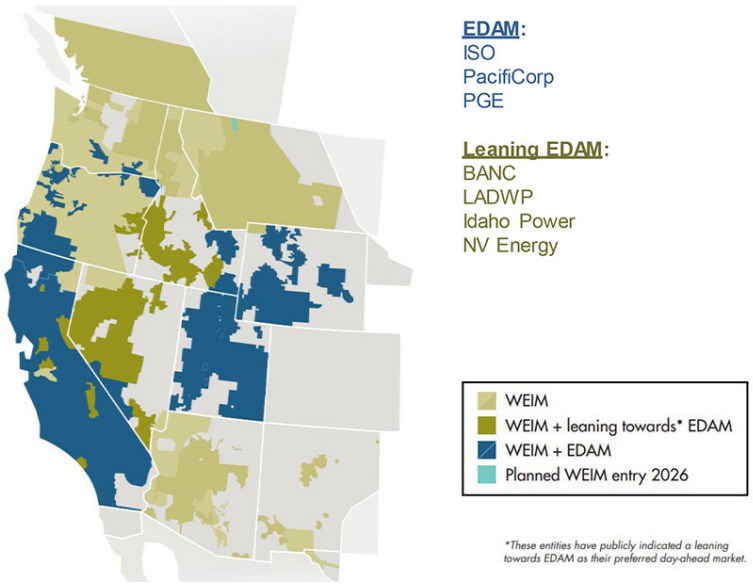
The future Western markets picture is in sharper focus now: We are progressing toward broad participation in two day-ahead markets. Such widespread participation in expanded market offerings may have seemed doubtful previously — even as recently as 10 years ago at the start of the Western Energy Imbalance Market (WEIM). Collaboration, determination and optionality have been critical to getting us to this pivotal point.

Scott Simms

Utilities and other market participants have recognized the potential benefits of expanded market participation and have worked hard to develop market options that meet their needs — including creative solutions that do not require participation in an RTO, new governance structures, and market designs that are compatible with continued OATT transmission service. Developing such options has facilitated organized market participation to grow, both geographically and in the breadth of services offered.

The passing of AB 825 marks a significant milestone for planned EDAM participants, laying the groundwork for implementing the Pathways "Step 2" proposal. This proposal will establish a newregional organization that will partner with CAISO to implement the Extended Day-Ahead and Western Energy Imbalance markets. At the same time, PacifiCorp and Portland General Electric have had their EDAM tariffs approved by FERC, and all signs indicate a 2026 go-live date.

Meanwhile, Markets+ also is moving forward with implementation. Nine utilities have made substantial financial commitments to secure the development of the market, with more utilities indicating their intent to join. In addition, many more participants and stakeholders are actively engaged in this final implementation phase. The market go-live is in 2027.



| CAISO

While we know there is frustration among some parties that a single market could not be achieved, ultimately the region should celebrate the collective progress that these markets represent and respect the decisions that each entity has made regarding its individual participation.

For entities such as PPC, Tacoma and BPA (as described in their Day-Ahead Market Policy Record of Decision, *Appendix B*), the risk of participating in a market that continues to have statutory ties to a single state or subset of market participants is untenable.

Even under the Pathways governance proposal — which is enabled by California AB 825 — CAISO continues to retain statutory obligations to the people of California and legally must be the operator of EDAM in order for California entities to participate. We respect the decision some entities have made that this level of independence is sufficient for their participation in EDAM, but it continues to be a deal-breaker both for us and for many others.

It is our hope that after many participants have made their market decisions, both market tariffs have been approved by FERC, governance structures are known, and implementation efforts are under way, we can all turn our attention to good faith efforts to make the soon-to-coexist market approaches in the region as successful as possible.

Achieving the additional efficiency and access to resources that will be offered by either market will benefit the region much more than having utilities not participating in organized markets — which is a likely outcome without the optionality that has been developed. As long as entities across the West remain committed to continued regional trade, coordination and reciprocal efforts to enable market participation, there can be significant benefits for the region at large.

We applaud our colleagues whose hard work, determination and collaboration were able to bring AB 825 over the finish line. Our hope is that we collectively can bring that same energy and genuine spirit of collaboration to the hard work needed ahead to successfully implement both markets, including seams negotiations when the time is right. ■

Chris Robinson is general manager of Tacoma Power and is the Public Power Council Executive Committee chair.

Scott Simms is the CEO & executive director of the Public Power Council.

Bipartisan Transmission Permitting Reform Bill Introduced in House

By James Downing

U.S. Reps. Scott Peters (D-Calif.) and Andy Barr (R-Ky.) on Sept. 26 introduced the Streamlining Powerlines Essential to Electric Demand (SPEED) and Reliability *Act*, which is meant to speed up the siting and permitting of transmission lines.

"We cannot wait a decade-plus for individual transmission lines to be approved if we don't want to fall behind China and our adversaries," Peters said in a statement. "This bill will lower costs for consumers, improve reliability and help secure America's energy independence."

The bill would alter the National Interest Electric Transmission Corridor (NIETC) program, which allows the Department of Energy and FERC to work together to designate transmission corridors that grant the commission backstop siting authority for lines inside them. The process was created in 2005 and updated during the Biden administration, which led to FERC Order 1977, but not one line has been built using it.

The SPEED and Reliability Act would remove the ability of the secretary of energy to designate corridors and would also centralize environmental reviews at FERC and include additional guardrails to protect customers, benefit local communities and respect state authority.

FERC would be able to issue construction permits for individual NIETC lines that reduce grid congestion, improve reliability, and offer customers clear economic and reliability benefits.

The reliability benefits would include facilitating compliance with mandatory reliability standards, cutting the risk of lost load and facilitating compliance with resource adequacy requirements on file with FERC, or offering similar material improvements such as lower outage risks as achieved through increased geographic or resource diversification.

The bill includes protections for consumers by only allocating costs to beneficiaries. Customers who get no, or just trivial, benefits could not be involuntarily allocated costs from NIETC lines under the bill, though nothing prevents utilities from seeking voluntary agreements with customers on cost allocation.

The Cardinal-Hickory Creek line under construction | *ATC and ITC Midwest*

Why This Matters

Previous permitting reform efforts have been holistic overhauls of U.S. infrastructure siting law. This latest bill focuses on electric transmission by altering the NIETC program, under which no project has ever been built in the 20 years it has existed.

The bill specifically pre-empts the siting and cost allocation for lines that go into ERCOT's territory. It would preserve current law by ensuring states have at least one year to respond to applications before firms can seek approval from FERC. And it would mandate that FERC engage with states, tribes and private property owners throughout the process.

The bill would apply to any transmission lines at 100 kV or above that would ship power for interstate commerce, including those on the Outer Continental Shelf, or foreign commerce.

The two congressmen's offices said the bill would help cut costs for customers through lower congestion and improved reliability/transfer capability during extreme weather events.

The bill would also help with economic development, as industries like artificial intelligence and microchip manufacturing lead to higher demand, with transmission enabling more development across the country including rural areas, they said.

"AI data centers and advanced manufacturing are at the core of America's economic future, but they can't run without reliable, affordable power," Barr said in a statement. "The SPEED and Reliability Act cuts red tape and builds the transmission lines we need to lower costs and ensure we stay ahead of China in the race for AI." ■

Federal Energy Policy News Roundup: House Bills and DOE Returns $13B

By James Downing

The House Sustainable Energy and Environment Coalition (SEEC) introduced its "Cheap Energy Agenda" on Sept. 24, which it calls a consumer-focused approach to energy policy and includes the *Cheap Energy Act*.

The bill, introduced by Reps. Sean Casten (D-Ill.) and Mike Levin (D-Calif.), addresses many issues and proposes big changes for FERC's authority.

"For too long, United States energy policy has prioritized the wants of energy producers over the needs of American consumers," Casten said in a statement. "It's past time things change. The Cheap Energy Act is a consumer-focused approach to energy policy that is rooted in American values like choice and competition. It will lower the cost of energy for American consumers by ensuring they have access to cheap, reliable and efficient energy."

In addition to reinstating the clean energy tax credits Republicans wound down via the One Big Beautiful Bill Act (OBBBA), the bill has a number of policy changes regarding FERC's authority, some of which Casten (a longtime *supporter* of the agency) has proposed in the past.

The bill would have FERC speed up interconnection queues, including promoting the use of automation and standardized study criteria. FERC also would have to change how it allocates costs for lines that are required to reliably bring new generation onto the grid — assigning costs to all beneficiaries and not just the new generator.

FERC would be required to start up an interregional transmission planning process and allocate the costs of such lines in a way roughly commensurate with benefits. Another idea that comes back up in the bill is that it directs FERC to establish minimum interregional transfer capability between regions — 30% of peak demand for most regions, but just 15% for those that border only one other region.

FERC would get exclusive siting authority over national interest transmission lines, which are defined as any that cross two or more states and have a capacity that exceeds 1,000 MW.

Each ISO/RTO would have to set up independent transmission monitors to facilitate the transparent and efficient deployment of new power lines. Another section, modeled after an old Casten *bill*, includes reforms to the ISO/RTO stakeholder and governance processes, which would start with a technical conference at FERC.

FERC would be required to establish a shared-savings program under which utilities are rewarded for providing real, independently verified cost savings to consumers. Another proposal would ban companies from trading in energy markets if they manipulate electric or natural gas markets.

The U.S. Department of Energy used Section 202(c) of the Federal Power Act to keep open a pair of fossil plants this summer and fall. The bill would change 202(c) by requiring the department to publish cost estimates for such orders. It also would prohibit DOE from issuing 202(c) orders for any reason that is more than a year in the future.

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House Republicans Pass a Couple of FERC-Related Bills out of Committee

The SEEC's Cheap Energy Act includes a wish list of reforms supported by Democrats, but Republicans have been using their majority to push through legislation in the House and its Energy & Commerce Committee. Before taking a break for the Jewish High Holy Days, the committee passed three bills in a Sept. 19 hearing.

"Today's passage of *H.R. 3062*, *H.R. 3015* and *H.R. 1047* reflects the House Committee on Energy and Commerce's relentless work to secure American energy dominance," Committee Chair Brett Guthrie (R-Ky.) said. "These bills streamline the permitting process for critical cross-border energy projects, restore expert advisory input from the coal industry that the Biden-Harris administration eliminated and ensure that electricity grid operators have the tools they need to secure the reliability of the bulk power system. With rising energy demand and growing threats to grid reliability, House Republicans are ensuring the U.S. has the tools to deliver affordable, abundant and reliable energy."

Former North Dakota state regulator and NARUC President, Rep. Julie Fedorchak (R-N.D.) introduced H.R. 3062, the Cross Border Energy Act, which would streamline the permitting process for natural gas and oil pipelines and electric transmission that connects the United States to Canada and Mexico. If the bill is enacted, FERC would review applications for pipelines and DOE for transmission, as opposed to requiring a presidential permit for cross-border energy projects now.

"The Keystone XL pipeline should have never been canceled. Yet on his first day in office, President Biden used the stroke of a pen to shut it down," Fedorchak said. "By passing my legislation, the House has taken a critical step to end years of regulatory uncertainty and partisan games that have delayed energy infrastructure projects, crushed good-paying jobs and undermined America's energy security."

The bill would stop future administrations from backtracking on permits that earlier administrations granted to infrastructure crossing borders.

Rep. Troy Balderson (R-Ohio) introduced H.R. 1047, which seeks to speed up the interconnection queue for "baseload" power plants like those that use natural gas. The bill gives ISOs and RTOs the authority to prioritize energy projects that are ready to bring baseload power on the grid immediately.

"The interconnection queue is overwhelmed and bogged down, leaving shovel-ready power projects waiting for years while demand continues to climb," Balderson said in a statement. "The GRID Power Act clears the path for the most critical projects, giving grid operators the tools they need to add more dispatchable baseload power — lowering costs for households and businesses while keeping America's grid reliable."

Expediting resources that advance reliability provides grid operators with additional tools to re-balance the resource mix and keep the lights, while reversing the "legacy effects of the Biden-Harris energy policies that continue to drive prices higher," the committee said.

DOE Announces $13 Billion in Biden Era Funds are Back in the U.S. Treasury

Speaking of reversing Biden-era policies, DOE announced Sept. 24 that it was returning $13 billion in unobligated funds initially appropriated to advance green energy policies.

"The American people elected President Trump largely because of the last administration's reckless spending on climate policies that fed inflation and failed to provide any real benefit to the American people," U.S. Secretary of Energy Chris Wright said. "Thanks to President Trump and Congress, those days are over. By returning these funds to the American taxpayer, the Trump administration is affirming its commitment to advancing more affordable, reliable and secure American energy and being more responsible stewards of taxpayer dollars."

The authorization to reverse the tax spending came under OBBBA, which the Trump administration has since rebranded the "Working Families Tax Cut," and is meant to rein in federal spending and return unobligated funds to the Treasury. Exactly what the money had been earmarked for is unclear, and DOE did not respond to a request to explain that.

Dallas Fed Survey Shows Some Worries about State of Oil and Gas Industry

Meanwhile, the Federal Reserve Bank of Dallas released its regular *quarterly survey* of oil and gas executives on Sept. 24. The survey includes projections for future fuel prices and some selected quotes on the industry. The survey found expectations for natural gas to cost $3.35/MMBtu in six months and $3.53/MMBtu in a year, which compares to the prompt month closing at $2.853/MMBtu on the NYMEX on Sept. 24.

The comments are anonymous, and many of them reflect the uncertainty in federal policy and argue that the Trump administration's actions are working against domestic oil production but are helping natural gas.

"Because of global circumstances, we think crude oil prices will stay low at the $60 per barrel level," one respondent said. "Alternatively, because of an increase in the LNG market, we feel that natural gas development and production will increase."

Another complained that the Biden administration had vilified shale oil and gas, which led to less investment, but things have not turned around since Trump took office.

"Guided by a U.S. Department of Energy that tells them what they want to hear instead of hard facts, they operate with little understanding of shale economics," an anonymous executive told the Fed. "Instead of supporting domestic production, they've effectively aligned with OPEC — using supply tactics to push prices below economic thresholds, knee-capping U.S. producers in the process. The collapse of capital availability has fueled consolidation by the majors, pushing out independents and entrepreneurs who once defined the shale revolution. In their place, a handful of giants now dominate, but at the cost of enormous job loss and the destruction of the innovative, risk-taking culture that made the U.S. shale industry great."

A third executive worried that aggressive anti-renewable policies from the Trump administration will not be good even for oil and gas in the long term.

"Day-to-day changes to energy policy is no way for us to win as a country," they said. "Investors (rightly) avoid investing in energy (of all types, now) because of the volatility of underlying business results as well as the 'stroke of pen' risk that the federal government wields as it relates to long duration energy developments. Life is long, and the sword being wielded against the renewables industry right now will likely boomerang back in 3.5 years against traditional energy, which will find itself facing harsher methane penalties, permitting restrictions, crazy environmental reviews and other lawfare tactics." ■

Wright: DOE Working to Stop More Coal Plants from Retiring

By James Downing

U.S. Energy Secretary Chris Wright said his department was working with utilities around the country to keep more coal plants slated for retirement open to help meet rising demand from data centers and other new large loads.

"What we're doing now is starting dialogues with utilities across the country, and I will tell you, there's a large amount of them," Wright said at an event hosted by Reuters during New York Climate Week on Sept. 25. "They're saying, 'Thank God.'"

At the time of President Donald Trump's second inauguration, there were plans to close up to 100 GW of firm generating capacity. Some of those plants — the older, smaller and least efficient — will shut down, but the Department of Energy is committed to keeping others open, Wright said. The interconnection queues contain mostly wind and solar, with plans for just 22 GW of firm capacity to be built to replace the 100 GW at the start of this year.

"We think we need 100 GW more of firm capacity in the next five years," Wright said. "So, if we got to get up plus 100, we certainly don't want to dig a hole to minus 78."

DOE has used its authority under Section 202(c) of the Federal Power Act to keep open two firm power plants in states with Democratic governors: the Campbell coal plant in Michigan, and the dual-fuel Eddystone in Pennsylvania. Its use of that authority broke with tradition as DOE has mainly used the law to keep plants running when needed for reliability and pollution regulations would otherwise limit their output.

Consumers Energy's J.H. Campbell coal plant | *Consumers Energy*

Why This Matters

Wright argued that the country needs to keep firm, dispatchable power plants open to help meet rising demand, but opponents argue keeping old, inefficient plants running only costs consumers money with no benefits.

Both of those orders were for this summer, and DOE has since extended them. Michigan Attorney General Dana Nessel and environmental nonprofits have challenged the Campbell order in a case that is working its way through the D.C. Circuit Court of Appeals. (See *Opponents Take DOE to Court over J.H. Campbell Retirement Delay*.)

The Sierra Club, which is one of the groups challenging the Campbell order, responded to Wright's comments, saying Big Tech companies behind the data centers that are a main contributor to load growth will be complicit in the "plan to take money out of everyday Americans' pockets and give it to the fossil fuel industry."

Consumers Energy — which owns the Campbell plant and had procured replacement capacity for it after a ruling from the Michigan Public Service Commission in 2022 to shut it down — said it would cost its customers $29 million in just over a month of operation under the 202(c) order. (See *DOE Extension of Michigan Coal Plant Cost $29M in 1st Month*.)

"Donald Trump and his fossilized friends have come up with yet another plan to force hardworking Americans to pay off Big Tech's energy bills to the tune of billions of dollars — all to prop up a few coal executives," Sierra Club Senior Adviser Jeremy Fisher said in a statement. "Clean solar and wind energy are the cheapest

and fastest sources of electricity, and yet this administration is putting its foot on the neck of a huge source of jobs."

DOE filed a substantive response to requests for rehearing Sept. 8. It noted that 1,575 MW of natural gas and coal-fired capacity had already retired in MISO since summer 2024.

"In the emergency order, the secretary determined that continued operation of the Campbell plant is necessary to best meet the emergency and serve the public interest for purposes of FPA Section 202(c)," DOE said in the rehearing order. "This determination was based on the insufficiency of dispatchable capacity and an anticipated increase in demand during the summer months, resulting in a risk to public health and safety caused by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages."

Opponents have argued that the department exceeded its authority in the 202(c) order for Campbell, but the department said it was responding to the potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is clearly allowed in the law.

The department also argued it is not required to work with states before it issues such an order, despite language in the DOE Organization Act that it consult with impacted jurisdictions "where practical." It argued it is often not practical before taking emergency action.

Michigan, other MISO states and the environmental groups all argued that no real emergency existed to warrant the 202(c) action, but the FPA gives the secretary the authority to determine that an emergency exists.

"Section 202(c)(1) delegates a wide degree of latitude for the secretary to determine the existence of an emergency, 'either upon its own motion or upon complaint, with or without notice, hearing or report,'" DOE said in the rehearing order. "Beyond providing exemplar categories of where an 'emergency exists,' the statute is silent on any additional requirements that must be satisfied."

The Maryland Office of People's Counsel wants to intervene in the Campbell case, but DOE filed against that motion Sept. 4, arguing that it is not an aggrieved party because the emergency order will not cost the state's ratepayers anything.

The OPC responded Sept. 12 arguing that the interconnections between MISO and PJM mean ratepayers in Maryland will be directly affected by keeping the plant running.

The order requires the continued use of a high-cost resource that will increase prices in both MISO and PJM, the office argued. It is difficult to quantify these costs, but "even a small amount of money is ordinarily an 'injury,'" the OPC said. "Maryland ratepayers are captive PJM consumers who, because of the order, cannot benefit from more economically efficient power imports and exports between RTOs, despite a planned, lower-cost replacement for the Campbell plant." ■

Centrus Moves to Expand HALEU Production Facility

Fuel is Key to Advanced Nuclear Plans, but U.S. Production is Minimal

By John Cropley

Centrus Energy has begun preparing for the massive expansion of its Ohio uranium enrichment plant that it will undertake if it receives federal funding.

The company is pitching the plan as an investment in the U.S. and its energy sector. Many of the advanced nuclear reactor designs being developed would be fueled by high-assay low-enriched uranium (HALEU), which is only produced in commercial volumes in Russia.

Centrus has begun small-scale production of HALEU in the Piketon, Ohio, facility with financial assistance from the U.S. Department of Energy. It is seeking further federal assistance to ramp up HALEU and LEU production there and said it will fabricate the new production equipment entirely in the U.S.

Company leaders joined with Gov. Mike DeWine, state and federal lawmakers, and economic development agencies on Sept. 25 to trumpet what would be a multibillion-dollar investment.

Centrus said the project would support 1,000 construction jobs and add 300 permanent jobs to the 127-strong workforce on site now. It would support hundreds more jobs at Centrus' Tennessee centrifuge factory and elsewhere in a manufacturing supply chain that spans 13 states.

The company said it has raised $1.2 billion in convertible note transactions and secured utility purchase commitments worth more than $2 billion in the past 12 months as it set the stage for the expansion.

Centrus added a caveat to the announcement: The size and scope of the expansion depend on funding decisions by DOE.

Why This Matters

The company is hoping to serve the huge potential demand for advanced nuclear fuel.

A worker at Centrus Energy's facility in Ohio | *JobsOhio*

No state grants, loans or tax incentives are planned so far, but the state-authorized nonprofit economic development organization JobsOhio is assisting with workforce development for the facility, which is in a rural region of southern Ohio with significantly higher unemployment and a lower median income than both the state and the U.S.

Centrus said it already has begun hiring in anticipation of the Piketon expansion; the Sept. 25 announcement came at an employment expo in nearby Chillicothe.

"The time has come to restore America's ability to enrich uranium at scale," Centrus CEO Amir Vexler *said in a news release*. "We are planning a historic, multibillion-dollar investment right here in Ohio — supported by a nationwide supply chain to do just that. When it comes to powering our energy future, it's time to stop relying on foreign, state-owned corporations and start investing in American technology, built by American workers."

The percentage of U.S.-made uranium concentrate processed into fuel for U.S. nuclear power generation began to decrease around 1980. In 2023, *99.85% of it was imported*.

This presents a potentially significant grid security issue, particularly as nuclear generation is pitched for a larger role in the grid. To remedy this, lawmakers and policymakers have been trying to boost domestic fuel production, including through the $2.7 billion funding package Centrus is hoping to tap.

The company has recorded successes, including a *national first* in late 2023 when it produced 20 kg of HALEU in Phase I of its DOE contract.

It checked off the Phase II requirements of the contract in June when it *delivered* 900 kg to the department.

Also in June, DOE exercised the first of its three *Phase III options* with Centrus to continue HALEU production at 900 kg/year.

And in late 2024, Centrus announced the department had awarded it an LEU contract and said it was scaling up its centrifuge manufacturing capacity to meet anticipated demand.

Centrus' stock price closed 13.1% higher in heavy trading Sept. 25. ■

Meta Files with FERC to Create Its Own Power Marketer: Atem Energy

By James Downing

With the age of hyperscalers ramping up, Meta is the latest major tech firm to ask FERC for market-based rate authority as it sets up its own internal power marketer: Atem Energy (*ER25-3440*).

Meta, which owns Facebook and Instagram, is one of many firms developing artificial intelligence applications that have been a major contributor to the resumption of overall power growth after a couple of decades of stagnation.

Atem Energy is a Delaware-based company that has been formed to act as a power marketer to sell energy, capacity and certain ancillary services at wholesale in the United States. The firm's MBR application does not specify where it will market power.

Meta is not the first big tech firm to seek MBR authorization: Alphabet's Google has had it since 2010 (*ER10-2835*), Amazon since 2015 (*ER15-1905*) and Microsoft since 2021 (*ER21-964*). Companies in other sectors have been at it even longer, notably Walmart, which set up its in-house power marketer, Texas Retail Energy, in 2002.

A major company setting up its own power marketer to secure power supplies comes with some benefits, but significant costs as well, Electric Advisors Consulting's Frank Lacey said in an email.

"In the plus column, you can design an electricity product tailor-made to your needs, including renewable attributes, risk management strategies, billing allocations and other," Lacey said. "You can also avoid the profit margins built into other suppliers' products.

"On the flip side of that coin, you have to build out an energy team, presumably with some trading and risk management expertise," he said. "You have to be registered with FERC to sell electricity at market-based rates. You need to be a member of each RTO you have facilities in and bear those costs, including credit requirements."

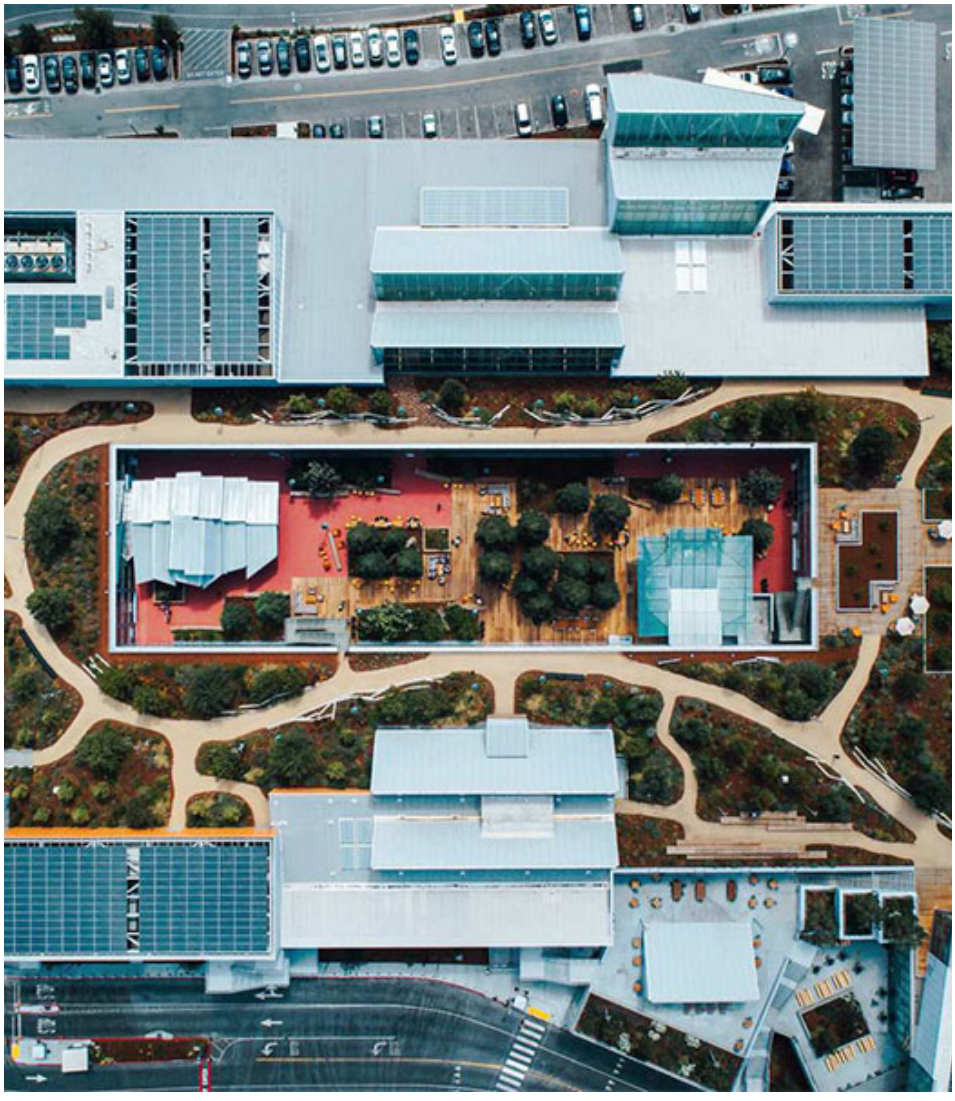
If Meta wants to become a state-regulated retailer to supply its facilities, it needs to register with their regulatory commissions and set up data exchanges with the relevant utilities, he added.

"You have to bear the risk of your own energy hedges and non-hedged positions, and as an RTO market participant, you own a share of the marketwide risk should any market participants go bankrupt," Lacey said. "If the company has the resources to do all of this, it might make sense. On the other hand, I would think a company like Meta would have enough horsepower to attract a lot of attention from the existing suppliers in the market."

Neither Atem nor its upstream ownership at Meta own any facilities that are for the generation, transmission or distribution of electric power. Meta CEO Mark Zuckerberg owns more than 10% of its shares, which triggers additional requirements, but he does not "directly or indirectly own or control a 10% or greater voting interest" in any generator or other energy assets in the United States, the application said.

The lack of existing assets in the power markets means Atem lacks horizontal or vertical market power, which satisfies the requirements for FERC to grant MBR authority, the application said.

The application seeks authority to sell ancillary services at market rates in CAISO, ISO-NE, MISO, NYISO, PJM and SPP. Atem asked for an effective date of Nov. 16, 2025, for its MBR authority. ■



Meta headquarters in Menlo Park, Calif. | *Meta*

Christie Appointed Director of New William & Mary Energy Law Center

By James Downing

William & Mary Law School *announced* Sept. 28 that it has appointed former FERC Chair Mark Christie as the 2025 Lowance Fellow, a visiting professor of the practice of law and the founding director of the school's new Center for Energy Law & Policy.

Christie served on FERC for nearly five years and was chair for the last seven months, until this past August. Before that, he was chair of the Virginia State Corporation Commission, on which he served for 17 years. He also previously taught law at the University of Virginia and Virginia Commonwealth University.

"I love the whole process of teaching," Christie said in an interview Sept. 29. "First of all, you got to learn before you can teach, and so teaching is very educational."

William & Mary said the new energy law center "will serve as a hub for convening policymakers, scholars and students to address critical issues shaping the future of energy regulation." Christie said the center offers him a chance to continue working on policy, with its first public activity being a conference scheduled for spring 2026 on how Virginia and the rest of the country can meet the needs of data centers and everyday consumers.

The center will also "host webinars on timely energy issues, sponsor research projects by William & Mary faculty and students, and promote cross-disciplinary collaboration across the university, including opportunities for business and policy students," the school said.

"We are ground zero for the planet for the challenges of data center development and the reliability and the consumer cost issues that the whole country is dealing with," Christie said. "Now, how do we pay for these? How do we keep the reliability? So, it's a perfect place to do this in Virginia and in William & Mary, which is an outstanding law school."

The return of load growth has put pressure on prices and reliability, which has led to calls for major changes at PJM, the largest RTO in the country and one Christie has tracked his entire career as a regulator. He recently spoke at a forum hosted by Pennsylvania Gov. Josh Shapiro (D) where he and other state governors in PJM called for reforms in its governance process. (See related story *PJM Members Confirm 2 Board Nominees; States Call for Governance Overhaul*.)

Shapiro and Virginia Gov. Glenn Youngkin (R) had asked that Christie and former FERC Commissioner Allison Clements be named to PJM's board. The governors raised the issue with Christie shortly after he left FERC, and he said he would have served if asked, but the RTO ended up picking others.)

"PJM faces a tremendous political problem, and when I say political, I'm not talking partisan; I'm talking the reality that you've got 13 states with obviously very different views about, certainly, what the generation mix ought to be," Christie said. "So, it's tough enough to try to come out with something that's a consensus among the states, but I'm looking to see that the states use the authority we gave them in Order 1920-B, which is to decide on cost allocation, and file that with FERC."

PJM is making policy calls around issues without giving the elected representatives of its 67 million consumers enough of a voice, Christie said.

Another policy issue that has come up lately and has periodically over the past 20 years is the role of the Independent Market Monitor. When Christie was president of the Organization of PJM States Inc., his yearlong tenure was taken up by a complaint states filed trying to preserve the independence of Monitor Joseph Bowring, the result of which was universal rules through FERC *Order 719*.

Former FERC Chair Mark Christie | © RTO Insider

But some interests in RTOs do not want IMMs at all. The idea has cropped up occasionally in PJM and just recently at MISO, where Monitor David Patton has clashed with stakeholders and leadership because of his views on transmission expansion. (See *MISO Board Orders More Detail into Monitor's 2026 Budget*.)

"I am not usually at a loss for words," he said. "People that know me would say that it's very rare that Mark Christie is at a loss for words. I can hardly even think of the words to describe how essential the market monitor is. …

"Consumers are absolutely, totally defenseless and regulators are totally in the dark [without a monitor] because I can tell you from my experience in PJM, I don't know how many times as a state regulator we got critical information from Dr. Bowring that we had to have to make decisions." ■

Why This Matters

Standing up the new Center for Energy Law & Policy at William & Mary School of Law ensures that Christie will continue to work on energy policy.

Trump Administration Takes Actions to Grow Coal's Role on the Grid

By James Downing

The Trump administration on Sept. 29 announced coordinated actions across three cabinet-level agencies to help boost the role of coal in the country's energy system.

The Department of Energy announced a $625 million investment to reinvigorate the coal industry by boosting production and supporting coal communities, which is in line with executive orders President Donald Trump signed earlier this year. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

"Beautiful, clean coal will be essential to powering America's reindustrialization and winning the AI race," Energy Secretary Chris Wright said in prepared remarks. "These funds will help keep our nation's coal plants operating and will be vital to keeping electricity prices low and the lights on without interruption. Coal built the greatest industrial engine the world has ever known, and with President Trump's leadership, it will help do so again."

The funds include $350 million for coal plant recommissioning and retrofits that the department said will help modernize power plants and provide near-term reliability and capacity. An additional $175 million is going to rural capacity and energy affordability projects that burn coal.

DOE is also putting $50 million toward the development and implementation of advanced wastewater management systems that demonstrate scalable, cost-effective systems that can extend coal plant life and cut operational costs. An additional $25 million is going to help coal plants implement dual-fuel capability, and $25 million will go toward developing and testing natural gas co-firing systems.

Meanwhile, EPA is providing steam electric power generation more time to comply with existing effluent limitations guidelines under the Clean Water Act to help meet growing demand. The action is expected to save $200 million annually in electricity costs, the agency said.

EPA Administrator Lee Zeldin also announced an Advance Notice of Proposed Rulemaking looking into changes to the Clean Air Act's Regional Haze Rule. EPA said that after years of feedback, "it is clear that the regional haze program is broken and needs significant revisions."

And the Department of the Interior announced it is opening 13.1 million acres of federal lands to lease for coal mining, lowering the royalty rates for mining and fast-tracking projects around the country.

"By reducing the royalty rate for coal, increasing coal acres available for leasing and unlocking critical minerals from mine waste, we are strengthening our economy, protecting national security and ensuring that communities from Montana to Alabama benefit from good-paying jobs," Interior Secretary Doug Burgum said in a statement. "Washington doesn't build prosperity; American workers and entrepreneurs do, and we're giving them the tools to succeed."

Why This Matters

The actions to boost coal are in line with executive orders signed by President Trump earlier this year and are aimed at helping the fuel that has lost out largely to cheap natural gas in recent decades.

Reactions to the three agencies' actions were mixed, with those who rely on coal plants praising them for helping to meet rising demand affordably, and others including leading environmentalists saying they would increase pollution and power prices for consumers.

"As electricity demand skyrockets, smart energy policies that help keep the lights on are more important than ever," NRECA CEO Jim Matheson said in a statement. "Today's announcements give electric co-ops important flexibility to reliably meet growing energy needs at a cost local families and businesses can afford. In recent years, misguided energy policies have forced essential power plants off the grid, while electricity demand surged. We thank the administration for moving swiftly to respond to growing energy needs with an emphasis on new tools, flexibility and a pro-energy policy agenda."

Environmental Defense Fund Director and Lead Counsel Ted Kelly said that subsidizing coal would saddle families with the cost of old power plants from the last century.

"This is not how you lower household costs, promote healthy communities, win the AI race or stay competitive in the 21st century," he said in a statement. "Today, solar, wind and battery storage are the cheapest and fastest ways to bring new power to communities and businesses. It makes no sense to cut off your best, most affordable options while doubling down on the most expensive ones." ■

Sheldon coal generating station, near Lincoln, Neb. | *Nebraska Public Power District*

Pathways to Engage Broad Set of Stakeholders to Select Independent RO Board

Launch Committee Outlines Next Steps

By Henrik Nilsson

The West-Wide Governance Pathways Initiative will soon begin the nomination process to select the initial board of the independent regional organization (RO) that will govern CAISO's energy markets, staff said during a Sept. 26 meeting shortly after the California legislature approved a bill to implement the initiative's plans.

California Gov. Gavin Newsom signed AB 825 into law Sept. 19, allowing CAISO and investor-owned utilities to participate in the independent Regional Organization for Western Energy (ROWE), which is being designed by the Pathways Initiative to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market. (See *Newsom Signs Calif. Pathways Bill into Law*.)

One goal is to remove what some see as a barrier to wider participation in CAISO markets by ensuring the markets are not governed solely by California, but rather by stakeholders from all Western states.

During the Sept. 26 *meeting*, Pathways Launch Committee Co-Chair Kathleen Staks reiterated statements she made earlier in the week that representatives from nine sectors will advise in nominating members to ROWE's initial board. (See *New Challenges Await Pathways After Success in Calif. Legislature* and *DER Representatives Get a Seat at the Pathways Table*.)

The sectors include:

- EDAM entities
- WEIM entities
- ISO participating transmission owners
- Non-IOU load serving entities serving load from WEIM or EDAM
- Public interest organizations
- Independent power producers, independent transmission developers and marketers
- Consumer advocates
- Large commercial and industrial customers
- Distributed energy resources

"The goal is to have that board selection process led by the nominating committee occur over the first six months of 2026, with a goal of seating that initial board in July of 2026," Staks said.

Additionally, the initiative's Formation Committee is reviewing feedback on ROWE's proposed bylaws and policies. The committee hopes to release revised bylaws in November. (See *Pathways Initiative Unveils RO Proposed Name, Bylaws*.)

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

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Why This Matters

With the success of AB 825, the Pathways Launch Committee now sets its sights on pulling together the regional organization authorized by the bill.

In a *follow-up letter* published Sept. 26, regulators from Arizona, California, New Mexico, Oregon and Washington congratulated the Launch Committee.

"We write once more to appreciate your dedication to the vision we articulated and celebrate the milestones you have achieved," the regulators wrote. "In particular, we note that pursuant to Pathways Step One, the Western Energy Markets Governing Body now holds primary filing rights for the tariff governing the energy imbalance and day-ahead markets. This approach incorporates customer protections across the market footprint. It also balances the needs of entities across the region to have transparency and certainty when committing to a day-ahead market."

The regulators also touted the benefits of an independent Western market, saying customers could save over $7 billion.

"We are moving into an era of unprecedented growth in electrical demand, new weather extremes, challenges procuring new generation and cost pressures. Indeed, affordability and reliability are central concerns in all our states," the regulators wrote. "This legislation provides a critical opportunity for us to address these issues, and we appreciate the time you have invested in realizing this critical milestone." ■

DER Representatives Get a Seat at the Pathways Table

Pathways Officials Provide Update to Nevada Transmission Task Force

By Elaine Goodman

As the West-Wide Governance Pathways Initiative dives into its next phases, a wide variety of stakeholders will serve as advisers — including representatives of the distributed energy resource sector.

"Developing the rules for resources participating in the market will … be shaped by that DER sector representative — something that doesn't exist anywhere else in the country," said Brian Turner, Western regulatory director for Advanced Energy United. Turner serves on the Pathways Launch Committee.

Turner's comments came during a Sept. 23 meeting of Nevada's Regional Transmission Coordination Task Force (RTCTF).

Distributed energy resources include rooftop solar and storage, electric vehicles and smart devices such as thermostats, Turner said. They can be aggregated into virtual power plants (VPPs) that can provide a boost to the grid at critical times.

Why This Matters

Wide stakeholder representation along with independent governance may be selling points for EDAM as it competes with Markets+.

AEU argued in a 2024 report that VPPs should play a greater role in resource planning in Nevada. (See *NV Energy Should Do More to Tap VPP Potential, Report Says*.)

Pathways stakeholder committee members from the DER sector "will help represent the interests of what will be hundreds of thousands of devices across Nevada being dispatched into the market," Turner said.

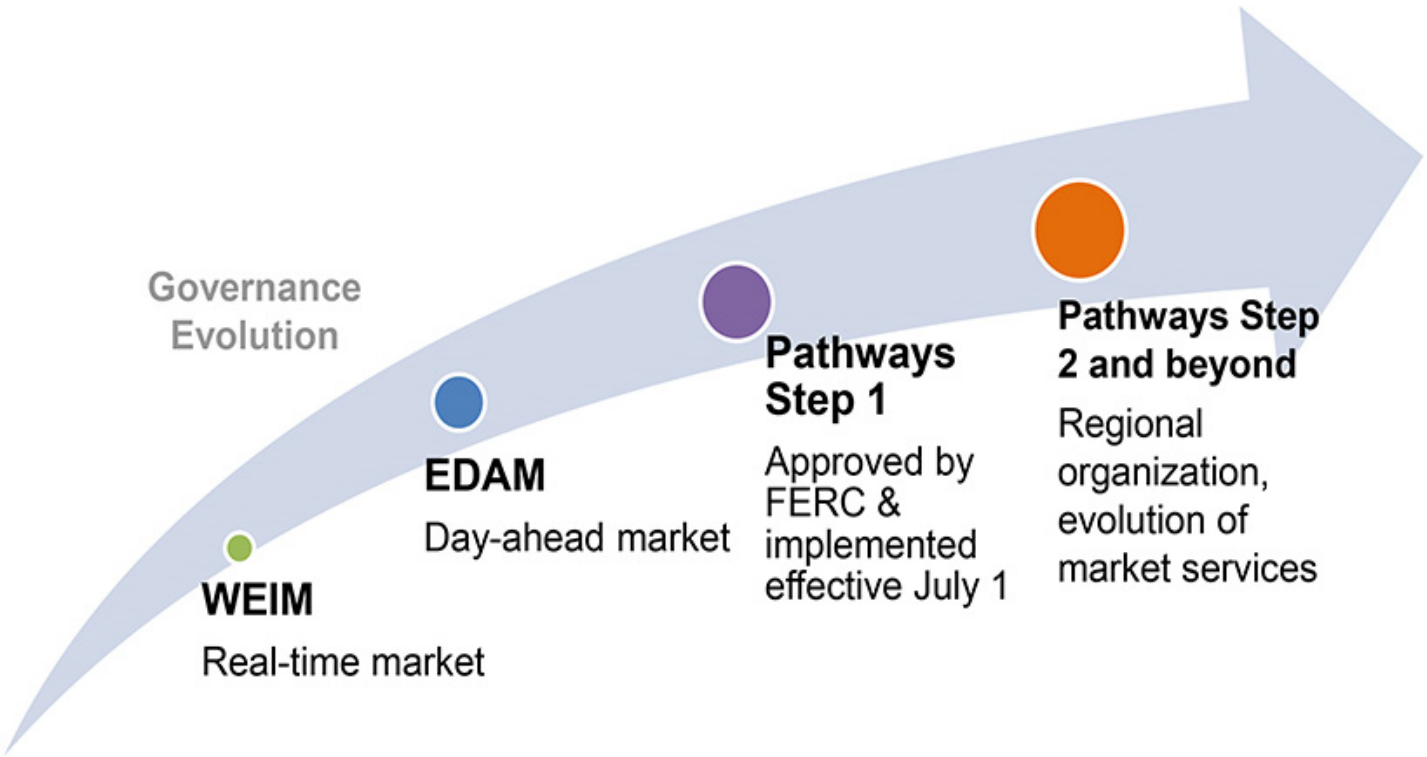
During its Sept. 23 meeting, the *RTCTF* heard updates on the Pathways Initiative as well as the Western Resource Adequacy Program and activities at CAISO and SPP.

The group, created through Senate Bill 448 of 2021, advises the governor and state legislature on energy issues, including those related to utilities joining an RTO.

Governance Transition

The Pathways Initiative aims to transition the governance of CAISO's markets from a board appointed by California's governor to an independent "regional organization" (RO). One goal is to remove what some see as a barrier to wider participation in CAISO markets, including the Extended Day-Ahead Market (EDAM) expected to launch in 2026. CAISO also runs the real-time Western Energy Imbalance Market (WEIM).

California Gov. Gavin Newsom on Sept. 19 signed Assembly Bill 825, which helps clear the way for the transition to RO gov-



The governance of CAISO markets is evolving as the West-Wide Governance Pathways Initiative makes progress. | *CAISO*

ernance. (See *Newsom Signs Calif. Pathways Bill into Law*.)

Kathleen Staks, co-chair of the Pathways Initiative's Launch Committee and executive director of Western Freedom, told the task force that Pathways is hoping to file incorporation documents with the IRS in January 2026. Once the RO board is seated, it will negotiate with CAISO on a contract to provide market services.

Representatives from nine sectors will participate in the nominating committee that chooses RO board members as well as a stakeholder committee that will identify and prioritize initiatives for the RO, Staks said. Some of the sectors represented will be new for the West, she said. In addition to DER sector representatives, the large industrial and commercial customer sector and the customer advocate sector will be represented.

Other sectors represented on the Stakeholder Representatives Committee include EDAM entities; WEIM entities; CAISO participating transmission owners; and independent power producers, independent transmission developers, and marketers, according to the Launch Committee Step 2 *final proposal* in November 2024. Some sectors may have more than one representative on the committee.

SPP Responds

Following a presentation from SPP, RTCTF Chair Jennifer Taylor of Enel North America asked what impact the passage of AB 825 would have on SPP. SPP's Markets+ is competing with CAISO's EDAM for day-ahead market participants, and SPP has pointed to the governance of Markets+ as one of its advantages.

Jim Gonzalez, SPP's senior director of seams and Western services, said SPP had been "built on a foundation of independen[t] governance."

"We've had decades of experience administering regional multi-state governance, delivering energy solutions across diverse jurisdictions," Gonzalez added. "That's something that's been a constant throughout not just the RTO but these different contract services."

With CAISO markets now moving toward independent governance through the Pathways Initiative, some are urging utilities that planned to join Markets+ to rethink their decision.

In Colorado, for example, California-led governance has been a key barrier to the state's large utilities joining a West-wide market, according to a Sept. 22 news release from Advanced Energy United, Western Resource Advocates and the Environmental Defense Fund. Public Service Company of Colorado received state regulatory approval in July to join Markets+. (See *Colo. PUC Approves PSCo's Markets+ Participation*.)

Passage of AB 825 means "the pathway to a bigger, better regional electricity market has opened in the West," the groups said.

"Colorado decision-makers and utilities should be rethinking prior decisions in light of this development so the state can have the strongest, most reliable, flexible, clean and affordable grid," Turner of AEU said in a statement.

But some market participants seem unlikely to budge from their Markets+ choice. Bonneville Power Administration previously told *RTO Insider* that despite the passage of AB 825, it believes Markets+ will provide greater customer benefits. (See *New Challenges Await Pathways After Success in Calif. Legislature*.)

In Nevada, NV Energy has expressed a preference for participating in EDAM, a step that requires approval from state regulators. ■

CAISO DMM Concerned About 'StubHub' Marketplace in RA Proposal

Other Stakeholders Offer Different Critiques of the ISO's Plan

By David Krause

CAISO's Market Monitor has cautioned that a new resource adequacy proposal could lead to strategic gaming in the ISO's market when capacity supplies are tight on the grid.

The Department of Market Monitoring voiced its concerns in Sept. 19 comments responding to a CAISO proposal that seeks to revise critical portions of the ISO's resource adequacy requirements and processes to help ensure RA capacity is available under tight conditions. (See *CAISO RA Initiative Moves Forward with 3 Proposals*.)

The proposal is part of a CAISO *Resource Adequacy Working Group* initiative that has prompted some stakeholders — including the DMM — to oppose a few of the potential changes.

Their concerns centered on two aspects of the *Track 2: Outage and Substitution straw proposal* released in August.

One aspect involves a plan for a new energy resource RA pool, while the other deals with an ISO policy requiring load-serving entities to provide substitute capacity during "conditional" resource outages.

The Track 2 plan attempts to address the fact that the ISO's current market design incentivizes LSEs to hold back RA capacity from the market in order to avoid potential penalties. This creates artificial tightness in the RA market, which CAISO and stakeholders say could be overcome with changes to outage substitution rules.

To address the issue, the Track 2 proposal calls for creating a decentralized matching system that would "function like a bulletin board for buyers and sellers to request or provide substitution capacity," the DMM said.

This marketplace would be a central clearinghouse to share information for direct bilateral transactions — one that CAISO compared with StubHub, a website that allows users to connect with each other to buy and sell event tickets. The advantage of such a marketplace would be decreased informational friction for scheduling coordinators to find replacement capacity, the ISO has said.

CAISO control room | *CAISO*

Why This Matters

The DMM and other stakeholders are expressing concern over some of CAISO's proposed RA rule changes as the ISO moves quickly for a Board of Governors vote on its plans.

However, DMM identified potential issues with this new design: Track 2's proposed marketplace could lead to a "strategic game of pricing" during tight conditions on the grid, it said.

The problem with the proposed design is too much transparency, DMM contends. The proposed marketplace would reveal supply- and demand-side prices, but not the true reservation — or opportunity — cost and value of capacity for buyers and sellers, it said.

Instead, DMM proposes an outage substitution pool design based on a reverse second price auction, in which buyers and sellers are incentivized to non-publicly reveal their true reservation prices for substitution capacity, rather than publicly as under the current proposal.

"DMM suggests that the product purchased in the auction could be analogous to the ISO's preferred option in the straw proposal, but use the auction mechanism instead," DMM wrote. "This would require the auction clearing on a unit of capacity per day, just as the proposed marketplace option in the ISO's currently preferred design. The main difference is the auction would clear re-

sources with the highest marginal value for substitute capacity, and bid prices would not be revealed to market participants."

This alternative approach would reduce market power concerns and be designed to disincentivize strategic interactions between market participants, DMM said.

The DMM's model would work well if the outage product and capacity available were for a single day of single week, a CAISO spokesperson told *RTO Insider* in an email. However, this approach becomes much more complex when the duration of outages and durations of supply to cover those outages are mismatched, the spokesperson said.

DMM's proposal includes "potential design and implementation challenges when this approach is applied in a manner that reflects scenarios for outage and substitution which often can require multiple days or weeks depending on the participant needs," the spokesperson said.

'Conditional' Outages Removed

In separate comments to the RA Working Group, other stakeholders shared concerns that the Track 2 proposal no longer includes a provision addressing the concept of "conditional" resource outages — instances when a resource has indicated it will be offline but has not provided substitute capacity.

CAISO could approve a conditional outage when reliability conditions allow, California Community Choice Association (CalCCA) said in its comments to CAISO. If reliability conditions changed, the ISO could then require the resource to provide substitute capacity, the group said.

"As a general matter, suppliers should be able to perform short-term maintenance without having to substitute capacity during non-stressed periods," CalCCA added. "This would allow for more opportunities to perform planned maintenance necessary to support reliable grid operation, minimizing potential maintenance delays and minimizing forced outages."

While CAISO would continue to allow off-peak opportunity outages that do not require substitute capacity, off-peak opportunity outages are only allowed during certain hours of the day and cannot extend multiple days, the CalCCA representative said.

Commenting on behalf of ACP-California, Energy Strategies' Caitlin Liotiris said the Track 2 proposal "dismisses the concept of conditional outages with little justification."

"We continue to believe that conditional outages can be implemented in a manner that fully preserves reliability and reduces costs for ratepayers, while also providing a valuable tool for RA resources to take outages without having to secure substitute capacity," Liotiris said.

Allowing conditional outages at least during non-summer, off-peak months would be a reasonable first step, particularly since CAISO used to approve such outages before implementing a full substitution requirement, Liotiris added.

But a CAISO spokesperson told *RTO Insider* the "conditional" outages concept was removed "for reliability reasons and challenges."

"The California Public Utilities Commission sets monthly RA requirements for LSEs under their jurisdiction to meet the reliability needs, and as such we do not anticipate that under such a construct there would be significant shown RA that could go on planned outage without substitution," the spokesperson said.

"In comments received on the issue paper, the CAISO heard many stakeholders disagree with the 'conditional' aspect of this approach and a desire for more certainty," the spokesperson added. "Removing this topic reflected the challenges in providing certainty desired by stakeholders without imposing a reliability risk to the system."

CAISO anticipates the Track 2 proposal will be reviewed by its Board of Governors in 2026, the spokesperson said. ■

Speculative Data Centers Highlight Need for Effective Forecasting, Experts Say

Dominion Energy, Georgia Power Both Adjusted Forecasts After Weeding out Projects

By Henrik Nilsson

Utilities face significant forecasting risks from large loads, prompting the industry to develop strategies to eliminate counting of speculative projects, experts said during a Western Interstate Energy Board webinar.

Natalie Frick, deputy department leader of energy markets and policy at the Lawrence Berkeley National Laboratory, and Shana Ramirez, director at Energy and Environmental Economics, discussed the challenges of large loads during a Sept. 12 webinar.

Citing data from the Electric Power Research Institute, Frick noted that all 25 utilities participating in a study on load forecasting reported challenges incorporating data centers into load forecasts.

About half of the utilities in the study included the full requested data center capacity in their load forecast, a third included a derated capacity and six utilities did not include any of the data center requests in their forecast at all, Frick said.

"All of the utilities that they interviewed identified that they're facing challenges with incorporating data centers into load forecasts, in particular because of the speculative nature of the service requests that they're receiving," Frick added.

There is no agreed-upon approach for load forecasting, but speculative load interconnection requests can skew the numbers across the board, Frick's presentation slides showed.

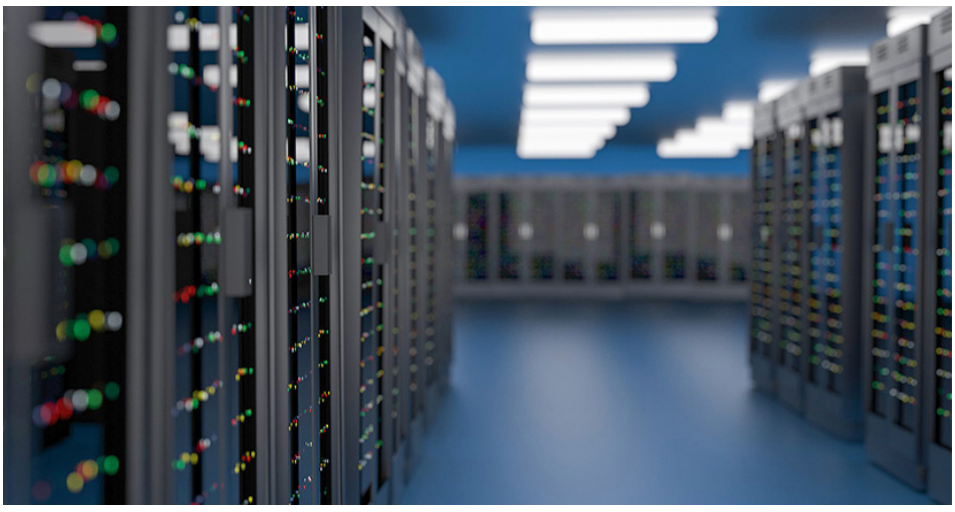
Georgia Power forecast a 107% compound annual growth rate for commercial large load summer peak load in the 2025 interconnection request process. However, several projects have pulled out, and net load reductions are concentrated across data center projects, "particularly those that were in the earlier stages of advancing through the interconnection process," Frick said.

Dominion Energy forecast $1.5 billion in data center capital spending between 2025 and 2027. However, after staff further reviewed the interconnection requests, they removed $853 million in data center expenditures "because they identified that those were speculative," Frick said.

"They didn't think that … those customers had enough skin in the game to really include them in the forecast," she added.

Additionally, there is no "standard large load tariff," Frick said.

"Regulators can design the tariffs to meet their state energy goals, and those could be a variety of things," she noted. "They could be seeking to improve or strengthen resource adequacy, affordability, attracting large load customers and also air pollutant emissions reductions. And so those are all kind of some of the motivations behind these tariffs."



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Notable Quote

"All of the utilities … identified that they're facing challenges with incorporating data centers into load forecasts, in particular because of the speculative nature of the service requests that they're receiving."

–Natalie Frick, Lawrence Berkeley National Laboratory

Ramirez highlighted that large load growth exposes utilities to nonpayment risks, as well as potential stranded assets and credit challenges, underlining the need for effective risk mitigation strategies.

Ramirez said there is a spectrum of what utilities are doing to mitigate those risks, ranging from "very lenient" to "very strict."

Dominion recently proposed collateral of $1.5 million/MW for large load customers that would be included in their rate costs.

This is "much higher than what we're seeing in other utility jurisdictions that probably have more risk, like Evergy Kansas, Evergy Missouri, where they're just asking for two years of minimum bills as collateral," Ramirez said.

Ramirez said there are some "best practices" utilities can implement. The practices should enable cost recovery, support responsible growth and promote fair treatment of all customers, according to the presentation.

"They should be flexible, transparent, consistent, scalable, adaptable and standardized, and [they] should align the financial security requirement with evolving risks," Ramirez said. ■

Data Centers 'Exacerbating' Tx Line Overload Forecasts in Bay Area

CAISO to Conduct Further Studies of Issue

By David Krause

The construction of new data centers could lead to transmission line overloads in the Bay Area, CAISO forecasts show.

Speaking during a 2025/26 transmission planning workshop Sept. 24, CAISO representatives said the Los Esteros-Metcalf 230-kV line in San Jose could become overloaded in both near- and long-term panning scenarios, with data center load "exacerbating this issue."

Potential data center loads also contributed "significantly" to forecast line and transformer bank overloads in the De Anza region, which is north of San Jose.

And in the East Bay region of the Bay Area, two of the East Shore 230/115-kV transformer banks and the Grant-East Shore 115-kV lines also show overloads under both near- and long-term scenarios, with a major contributing factor tied to forecast data centers, CAISO said during the workshop.

Kanya Dorland, a senior analyst at the California Public Utilities Commission, asked if forecasted overloads in Palo Alto were also due to planned data centers.

"And if it is data centers, do you have confirmation that the data centers have control of the sites that they are going to be located at?" Dorland asked at the workshop.

"We have modeled these data servers from the [California Energy Commission] load forecast," a CAISO representative on the call said. "At this point, we don't know which overloads are caused by individual loads."

© RTO Insider

Why This Matters

The prospect of new data center load is proving to be a challenge for the Bay Area grid in the same way as other parts of the U.S.

"You don't have any information about what is driving the overloads?" Dorland said.

"Right now, we haven't dug into what exactly is creating the overloads, which we plan to do after this stakeholder meeting as part of mitigation development," the representative said. "And then, from there on, we need to coordinate with Pacific Gas and Electric to see what they are finding as part of their load interconnection study and see what upgrades are necessary."

"It would be great to have more transparency to show the amount of overload is contributed by data center loads," Dorland said.

The representative said the ISO can't guarantee that "we will be able to provide that kind of information."

In Palo Alto, CAISO said there is a planned upgrade project of a 115-kV line, which will help alleviate some of the overload issues, but other issues will continue to persist. Compared with the previous transmission planning cycle, Palo Alto's load forecast increased by 47 MW in 5 years, 70 MW in 10 years and 78 MW in 15 years.

In CAISO's transmission planning process this year, the ISO implemented a new load modifier to represent data centers — the Data Server modifier.

The ISO is continuing to study potential transmission system overloads as part of its transmission planning process and will include recommendations in its draft transmission plan by the end of March 2026, CAISO told *RTO Insider*. ■

BPA Provides More Details on 2028 Residential Exchange Program

Agency Staff Discuss New REP During Workshop

By Henrik Nilsson

The Bonneville Power Administration is developing the next phase of its Residential Exchange Program (REP) and presented proposed provisions during a Sept. 24 workshop.

The REP helps residential and farm customers of higher-cost Pacific Northwest utilities — mainly investor-owned utilities — access lower-cost federal power reserved for public power customers. The REP is currently managed under a settlement that expires Sept. 30, 2028, and the agency is developing the next phase of the post-2028 REP agreement.

The Sept. 24 *workshop focused in part* on the REP's in-lieu provision, which means that "instead of purchasing any amount of power offered by a utility, BPA may acquire power from other sources and sell that power to the utility if the cost of such power is less than the utility's [average system cost]," according to BPA's presentation.

Under the proposed post-2028 REP in-lieu provision, BPA must provide notice to the utility 10 months prior to implementing or scheduling the in-lieu power. Additionally, once BPA issues the notice, the IOU has 30 days to opt out of the in-lieu power.

The notice would include the amount of in-lieu power expressed in monthly increments in MW and MWh, how much BPA paid to acquire the in-lieu power, duration of the in-lieu power sale, source of the power and the customer's point of delivery, according to the presentation.

The Northwest Power Act *established the REP*, which is structured as a power exchange where utilities with high-cost resources sell power to BPA at their average system cost (ASC) of resources, and BPA, in turn, sells the same power quantity back to the utilities at BPA's cost of power. No actual power is transmitted; the deal is instead treated as a financial transaction, according to BPA documents.

Specifically, the agency pays the IOU the net difference between the two sales, multiplied by the utility's qualifying residential and farm load. The cost benefits of the exchange are passed on to the utility's retail residential and farm consumers as a credit on their power bill.

Public Power's Input

In a Sept. 17 *letter*, a group of public power organizations and utilities said BPA's proposal to implement the post-2028 REP through a financial settlement rather than physical delivery of power "is consistent with BPA's statutory obligations and authorities."

"Also, the practical constraints with implementing the REP through physical deliveries appear daunting, if not impossible to overcome," the authors said.

The organizations also wrote that consumer-owned utilities have "first right to federally generated power."

"BPA's proposal to implement REP through a financial settlement ensures that the statutory preference rights of the COU's are preserved notwithstanding the purchase and exchange sales authorized under section 5(c) of the Northwest Power Planning and Conservation Act, as intended by Congress when the act was passed in 1980," the authors said.

The organizations said also they are unable to take a stance on duration, activation, termination and suspension issues discussed during a Sept. 11 workshop. The letter stated that "consideration of these issues hinges on their alignment with rate periods and ASC submittals."

"Accordingly, at this time, public power is unable to take a position without a better understanding of how important aspects of BPA's financial policies will be implicated, as well as potential linkages to the 'in-lieu' provisions in the Residential Purchase and Sale Agreement (RPSA)," the letter stated.

"In particular, if the Cost Recovery Adjustment Clause, Financial Reserve Policy Surcharge or Reserves Distribution Clause are triggered, a significant shift in benefits could occur," public power argued. "We would like to better understand the impact of these tools on the REP as it relates to duration, activation, termination and suspension issues, including whether investor-owned utilities will share in the costs and benefits of BPA's risk mitigation tools for power services."

BPA will release a draft of the RPSA on Oct. 29 for comment and input. The agency will hold the next workshop Oct. 9. ■

Why This Matters

How BPA sets the rules around the REP could have wide ranging implications for IOUs and COUs in the region.

BPA headquarters in Portland, Ore. | *DOE*

ERCOT Board Approves Ancillary Service Procurement for 2026

Directors Briefed on RTC+B, Summer Ops

By Tom Kleckner

ERCOT's Board of Directors on Sept. 23 approved staff's recommended methodologies for acquiring minimum ancillary service requirements in 2026, but not before revisiting the same discussions that stakeholders have had in recent weeks over conservative operations and target procurement levels.

The board's approval allows ERCOT to use a probabilistic methodology — an analytical approach incorporating randomness and uncertainty by assigning probabilities to outcomes and events — to calculate hourly ERCOT contingency reserve service (ECRS) and non-spinning reserve service quantities. The probabilistic model aligns ECRS and non-spin requirements with the risk profile, where higher risk equals a higher requirement and lower risk equals a lower requirement.

Staff's proposal also makes minor changes to regulation service and responsive reserve service (RRS).

"I appreciate the tension between reliability and efficiency and cost effectiveness," ERCOT CEO Pablo Vegas said as the hourlong discussion, scheduled for 20 minutes, wound down. "That's a tension that I think we all deal with in what we do day to day."

The Independent Market Monitor again made the case that ERCOT is overprocuring non-spinning reserves and other long-lead-time ancillary services. It offered a compromise that halved the length of staff's recommended look ahead at forecast errors or forced outages, from six hours to three, saying it would be just as reliable as staff's proposal but for less cost.

The Monitor also joined the consumer stakeholder segment in suggesting an end to the grid operator's conservative operations approach, which stockpiles operating reserves in anticipation of tight conditions.

"Somebody needs to figure out what the offramp is from conservative operations, so that we're not just doing this forever," IMM Director Jeff McDonald said. "I feel for ERCOT having been put in a situation where they have to incorporate that kind of an unwritten policy directive into their actual reliability operations, but there's got to be an offramp for that."

ERCOT Director John Swainson pushed back against the Monitor's recommendation. He questioned McDonald's suggestion after ERCOT staff had said they were following the Texas Public Utility Commission's criteria. In a *2024 report* on ancillary services, PUC staff found conservative operations should be maintained to balance system improvements made since the February 2021 winter storm until additional data are available.

"We have no idea how you calculated or what the hell you've done, and you come up with a different answer," Swainson said. "We just can't believe you. I mean, your credibility with us as directors is zero."

"I'm not really sure how to address that," McDonald said in response.

PUC Chair Thomas Gleeson offered McDonald a lifeline, saying the IMM and Potomac Economics' David Patton have spent "a lot of time with me" on the issue as recently as the prior weekend.

"I'm in agreement with the IMM that we need to look at all of this," he said. "I don't think we should ignore the price formation aspects of the posture that we've taken … to ignore the price-formation impacts of the conservative operations posture that we've taken would be foolish, at least as I sit here as a commissioner."

Gleeson pointed to ERCOT's Real-time Co-optimization + Batteries (RTC+B) project, to be deployed in December, and reliability standard analysis that will take up much of 2026 as reasons to wait before making further market changes.

"While I agree that we need to look at this and potentially make some changes in this direction, I think it is more prudent to wait until next year," he said. "I think this needs more discussion."

Why This Matters

Concerns remain over conservative operations and target procurement levels, and one ERCOT director pushed back against the IMM's recommendations over the issues.

Adding "real time co optimization + batteries into the market is going to be one of the biggest market changes economically and operationally that we've gone through in over a decade," Vegas said, agreeing with Gleeson that "it's very prudent to see the impact of that over multiple cycles."

In the end, the board agreed with staff and other stakeholders to wait until 2027 to revisit and further examine ancillary service methodologies for potential adjustments.

RTC+B Completes Major Test

"It feels like if it's a football game, we're first down and goal from the 8-yard line," ERCOT's Matt Mereness said in briefing the board on the *RTC+B project*. "There's still a way to go, but things have been going pretty well."

Mereness, senior director of market operations and implementation and the RTC+B project manager, said the initiative is five months into market trials and testing and stabilizing systems. The first of two planned production tests was conducted Sept. 11; ERCOT operators controlled the real-time market and frequency for two hours, and market participants were able to submit accurate telemetry, bids, offers and follow RTC+B dispatch, he said. The RTC+B systems were able to award and dispatch energy and ancillary services in real time every five minutes.

A second production test is scheduled for Oct. 30. ERCOT's most significant market redesign since the switch from zonal

to nodal in 2010, RTC+B is scheduled to be deployed Dec. 5.

"We don't normally take six months to implement something, but when you implement a major redesign of your real-time market and your four-second control of the system, you need to test it," Mereness said. "It's not just about ERCOT being successful. It's about 95 other companies that are batteries, resources and generators that have to move their machines."

During the first production test, solar and wind energy dropped by 3,000 MW and two units tripped offline, but "other things" picked up.

"It wasn't necessarily an easy-peasy test like some of us thought it would be," Mereness said. "The good news is that the operators and engineers are now looking at how [our system reacted]. The nice part of actually doing a dress rehearsal is people look at the money; they look at the megawatts; and they see if they can follow."

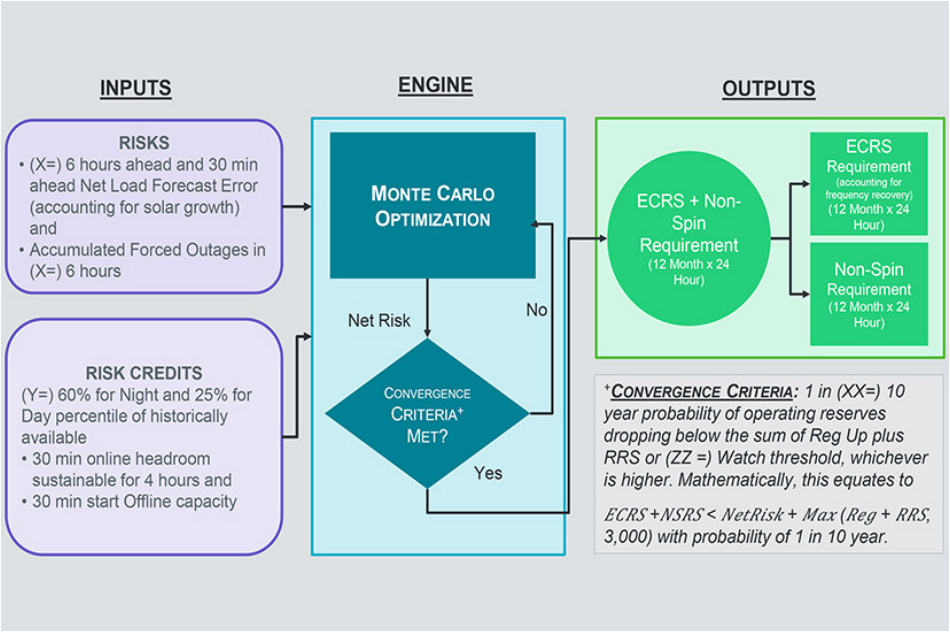
ERCOT plans to publish a market notice Nov. 5 to alert market participants that RTC+B is live and the transition has begun.

Another 'Mild' Texas Summer

Barring an unseasonable warm spell during the fall, ERCOT will go a second straight year without setting a new demand peak, Vegas said during his *update* to the board. The grid operator recorded a high of 83.68 GW on Aug. 18, less than 2 GW from the all-time peak of 85.51 GW set in August 2023.

While no new peaks were set during a "mild" summer — the June-July period was only the 43rd-hottest in recorded history — ERCOT's energy consumption has grown year over year. Vegas said the consumption, which increased 2.53% from 2010 through 2020, has doubled to 5.12% since then.

"This is a little bit like the proverbial frog that's boiling slowly in a pot of water … and doesn't realize that it's actually boiling," he said. "This is what's happening here. Under the surface, we've got energy growth growing very rapidly, but because we haven't had extreme weather events in the last couple of years, we have not seen new peak demands push up that peak demand level any higher. It's important to not ever be lulled into complacency."



ERCOT's probabilistic approach to procuring ancillary services in 2026 | *ERCOT*

Vegas said ERCOT is at an "inflection point of an acceleration of demand growth." Fortunately for the ISO, staff are analyzing 6,000 MW of new generation that will be synchronized to the grid in the first quarter of 2026. That's the most ever studied at one time, Vegas said.

Energy storage resources (3,042 MW) and solar (2,055 MW) account for much of the generation, with four gas projects accounting for the remainder (1,103 MW). Vegas said the first three Texas Energy Fund projects are among the gas projects under study. (See *NRG Energy Secures $216M Loan from TEF*.)

"This is a positive trend," he said.

Solar and ESRs continue to be the ISO's workhorses during the critical afternoon hours. Solar set four records during the summer, the last on Sept. 9 (29.83 GW); the 29.34-GW solar peak July 29 broke the grid operator's mark for wind generation (28.47 GW) for the first time. ESRs also set records this summer, with a high-water mark of 7.51 GW on Sept. 10.

"The additions of solar and batteries have helped us handle the growth in the summer months, where we've seen a lot more consumption," Vegas said.

Board Approves Transmission Projects

The directors approved two regional transmission projects that could cost as much as $827 million to build and that have been recommended by ERCOT's Regional Planning Group and passed the Technical Advisory Committee. (See "$827M in Tx Projects OK'd," *ERCOT Stakeholders Endorse 2026 AS Methodology*.)

CenterPoint Energy's *Baytown Area Load Addition project* in the petrochemical industrial region east of Houston is projected to cost $545.3 million for 45 miles of 138-kV lines and additional capacitors. CenterPoint submitted a $141.7 million estimate to address reliability issues caused by proposed new load; ERCOT staff said additional temporary work would be required for all structure replacements, accounting for about 45% of the capital costs, maintenance-outage issues and the expense of rebuilding 138-kV lines among industrial facilities.

Bryan Texas Utilities' *Texas A&M University System RELLIS Campus project* has an estimated capital cost of $282.1 million. The project includes 40 miles of new 345-kV double-circuit lines to the *RELLIS campus*; constructing or rebuilding about 10 miles of 138-kV lines; and expanding the campus' existing 138-kV substation.

Benjamin Barkley, CEO of the Texas Office of Public Utility Counsel, abstained from the vote on the Baytown project.

The board also approved a *price correction* for the day-ahead market on its June 27 operating day. ERCOT said a software malfunction related to a generic transmission constraint affected day-ahead prices and wasn't discovered until after the two-business day deadline

for corrections.

The correction resulted in a maximum absolute value effect of $26,525 to counterparties and $124,385 due to ERCOT.

Complete Board Seated

Independent Directors Christopher Krummel, Kathleen McAllister and Bill Mohl, fresh off recent selections to the board, participated in their first meetings Sept. 22-23. They have also been appointed to the board's subcommittees, which are fully rostered for the first time in 2025. (See *ERCOT Fills out Board with 2 Final Selections*.)

Consent Agenda Passes

The board's consent agenda included 10 nodal protocol revision requests (NPRRs), three changes each to the Planning (PGRRs) and Settlement Metering Operating (SMOGRRs) guides, two modifications to the Nodal Operating Guide (NOGRRs), single revisions to the Variable Cost Manual (VCMRR) and Retail Market Guide (RMGRRs), and a system change request (SCR) previously endorsed by TAC that will:

- *NPRR1265*: implement procedures for distributed generation reporting by clarifying DG's definition and defining the new term, "unregistered distributed generators" (UDGs). The NPRR would establish procedures for UDG reporting to ERCOT and reporting requirements from the ISO.
- *NPRR1266*: specify that a transmission-voltage customer that is a securitization uplift charge opt-out entity may not transfer its status to other entities. The measure adds a requirement that a transmission service provider (TSP) associated with an electric service identifier originally granted opt-out status must compare at least monthly the names of transmission-voltage customers originally granted the status and inform ERCOT of any changes. The TSP requirement excludes those that are securitization uplift charge opt-out entities.
- *NPRR1277*: revise the minimum current exposure and estimate aggregate liability (EAL) formulas, improving the efficacy of existing credit formulas that measure credit exposures in the ERCOT market. The EAL formula revisions include applying the real-time forward adjustment factor against the respective days' real-time liability estimated (RTLE) and then taking the max over the lookback period; and introducing seasonal variability in the lookback period as it is applied for RTLE.

Texas PUC Chair Thomas Gleeson explains his thoughts on conservative operations. | *ERCOT*

- *NPRR1279*: enable generation resources to file exceptional fuel costs that include contractual and pipeline-mandated costs and strengthens the process for ERCOT and the Monitor to verify the costs.
- *NPRR1281*: strengthen the relationship between the settlement of firm fuel supply service (FFSS) and operations by clarifying its hourly rolling equivalent availability factor language to ensure the accurate calculation of the FFSS standby fee.
- *NPRR1283*: require that any necessary subsynchronous resonance studies be complete and mitigation be in place before the initial synchronization of an ESR, new generation resource or a settlement-only generator before the initial energization.
- *NPRR1288*: simplify the congestion revenue rights (CRR) auction by removing the ability to transact in multiple month strips that create optimization issues for ERCOT.
- *NPRR1289*: provide an option pricing report that would be posted following each CRR auction. The report will contain shadow prices for all biddable source-sink paths for each month within each time of use for the auction period and establish a minimum CRR bid of 1 MW.
- *NPRR1290*, *NOGRR278*: address several gaps and clarify protocol language to support the RTC+B initiative's implementation.
- *NPRR1291*: incorporate the Texas PUC's substantive rule setting a goal for average total residential load reduction into the protocols, specify data exchange methods and formats, and extend the deadline for posting the annual demand response report.
- *NOGRR272*, *PGRR121*: establish new advanced-grid support requirements — including model-quality tests and unit validation requirements — for inverter-based ESRs with a standard generation interconnection agreement executed on or after April 1, 2025.
- *PGRR120*: prevent generators from interconnecting to the ERCOT grid if they would be radial to a series capacitor under N-1 conditions.
- *PGRR129*: establish requirements for posting the Grid Reliability and Resiliency assessment and update a list illustrating data sets and classifications.
- *RMGRR183*: incorporate several updates that have been implemented as part of previous project improvements to transmission and/or distribution service providers' Competitive Retailer Information Portal self-service tool. TDSPs will be able to assign weather moratoriums by county name instead of service territory.
- *SCR832*: discontinue and eventually retire a report not being used by market participants.
- *SMOGRR032*: incorporate the Other Binding Document "TDSP Access to EPS Metering Facility Notification Form" to standardize the approval process.
- *SMOGRR033*: incorporate the Other Binding Document "*TDSP Cutover Form for EPS Metering Points*" to standardize the approval process.
- *SMOGRR034*: remove obsolete gray-box language associated with *NPRR1020* (Allow Some Integrated Energy Storage Designs to Calculate Internal Loads).
- *VCMRR044*: set the variable operations and maintenance cost in the mitigated offer cap for hydro generation resources to the real-time systemwide offer cap and the incremental heat rate value to zero. ■

Vistra to Build 2 Gas Units in Oil-rich Permian Basin

Company Inks PPA for 1.2 GW of Nuke Power from Comanche Peak

By Tom Kleckner

Vistra said Sept. 29 that it will build two new advanced natural gas power units at its Permian Basin Power Plant in West Texas, adding 860 MW of capacity to a petroleum-rich region that is rapidly undergoing an electrification transformation.

The two units will triple the Permian Basin facility's current capacity from 325 MW to 1,185 MW. The site currently has five combustion turbines, each about 65 MW.

The new gas units are part of *Vistra's plan* to add up to 2,000 additional MW of gas-fueled dispatchable power in ERCOT by 2028.

"Given Vistra's fleet, interconnections and experience in improving, redeveloping and building power plants, we are uniquely positioned to deliver solutions that provide reliable, affordable power to our residential customers, as well as industries across Texas and the United States," Vistra CEO Jim Burke said in a *press release*.

The Irving, Texas-based company said that in 2024, it identified more than $1 billion worth of potential capital additions in generation capacity within the ERCOT market, if market conditions were "supportive." It added about 1 GW of new generation capacity between 2020 and 2023 by increasing the gas fleet's output and bringing three new projects into commercial operation.

"Vistra's bold investment in the Permian Basin will reinforce our state's electric grid, spur jobs and drive regional economic growth for years to come," Texas Gov. Greg Abbott said in the release.

Vistra says it is adding 860 MW of gas-fired capacity at its existing Permian Basin facility to meet growing demand. | *Vistra Corp.*

Why This Matters

Vistra's announcement is part of its plan to spend $2 billion in capital to add 3,100 MW of capacity to the ERCOT grid by 2028.

Vistra said it has made "significant progress" on other projects announced since the summer of 2024, including:

- completing upgrades at gas plants that have added more than 400 MW of capacity across its Texas fleet;
- plans to repower its Coleto Creek Power Plant — a coal plant scheduled for retirement in 2027 — as a 630-MW gas-fired unit; and
- nearly completing a 200-MW solar project on the site of a retired and reclaimed lignite mine, with commercial operations expected by year's end.

When the projects are completed, Vistra will have invested nearly $2 billion to add about 3,100 MW of new generation capacity in the state since 2020.

Nuclear Power PPA Signed

Vistra also said in an *8K filed* Sept. 29 with the Securities and Exchange Commission that it has entered into a 20-year power purchase agreement with a "large, investment-grade" company for 1,200 MW of power from its Comanche Peak nuclear plant.

The company expects power delivery to begin in the fourth quarter of 2027 and ramp to full capacity by 2032.

Vistra declined further comment on the counterparty or the PPA. A spokesperson said the counterparty is finalizing its plans and it will share further details when they are available.

Bank of America Securities said in a *research report* that it estimates the PPA will price around $105 to $120/MWh, with a midpoint of about $112/MWh. ■

Stakeholders Press IESO on Governance, Transparency

ISO Acknowledges Desire for Increased Stakeholder Input

By Rich Heidorn Jr.

IESO's plan to give its staff authority to set market parameters without approval by the Board of Directors has sparked a debate over the ISO's governance and the role of stakeholders.

The board has been responsible for setting parameters used in the calculation engines since the ISO's market launch in 2002. But the changed composition of the board and increasing complexity under the Market Renewal Program (MRP) mean the process is "outdated," Josh Duru, senior market rules and manuals adviser, said in an *engagement session* Sept. 16.

The parameters include the maximum market clearing price (MMCP), maximum operating reserve price (MORP), constraint violation penalties and floor prices for variable generators, and "flexible" nuclear. The MRP added the determination of the settlement floor price to the board's responsibilities.

Under the *proposed change*, the parameters would be set by IESO, "with stakeholder input, in the same way in which most other market rule requirements are established," the ISO said. The board would "maintain its usual oversight and approval function but should not be required to set technical parameters directly."

Changes to the Board of Directors

"At market opening, the board had 15 members, nine of which were stakeholder directors. So, at that point in time, they had the … very technical knowledge in order to set these values," explained Jo Chung, supervisor of market rules and manuals. "But over the years, that has obviously changed, and we don't have that stakeholder representation directly on the board."

The composition of the board changed as part of the 2015 *merger* of IESO and the Ontario Power Authority.

The board, which is appointed by the provincial government, *currently includes* CEO Lesley Gallinger and five others:

- interim board Chair David Collie, former CEO of the Electrical Safety Authority of Ontario and a former executive at Burlington Hydro and Hydro One;
- Simon Chapelle, who runs a consulting firm focusing on telecommunications and rural economic development and is former municipal councilor for the city of Kingston;

The Richmond-Adelaide Centre in Toronto, home to IESO offices | *Oxford Properties*

Akira Yamamoto, TransAlta | *Independent Power Producers Society of Alberta*

- Frank Fazzari, head of accounting firm Fazzari + Partners;
- Tom Mitchell, former CEO of Ontario Power Generation (OPG); and
- Robert Wong, principal of executive consulting firm Hesketh Sloane Advisory and former chief information officer at Toronto Hydro-Electric System.

Stakeholder Concerns

The proposal to change how parameters are approved led to a lengthy debate during the webinar about the ISO's governance and transparency.

"This seems like a pretty dramatic change, despite the fact that it's being portrayed as something different," said Akira Yamamoto, director of regulatory and market policy for TransAlta.

Yamamoto said other grid operators have an "independent adjudicator" involved in approving changes for essential parameters such as price floors and caps.

"That whole process … in Ontario is a little bit more inside baseball, but there was some process," Yamamoto said. "And I think the entire elimination of it raises pretty significant concerns about how dramatically the market design could potentially be changed at, ultimately, a staff level."

Chung insisted the change is not intended to undermine transparency and noted that the MMCP and MORP have not changed in more than 20 years.

Role for Technical Panel on Manuals

The discussion also touched on questions over what goes into the market rules, rather than the market manual, and when the ISO should bring such changes to the Technical Panel for public discussion.

The Technical Panel has authority over changes to market rules but not manuals. (See *What to Know About IESO*.)

"That's always been a debate," said Julien Wu, director of regulatory affairs at Brookfield Renewable's *Evolugen* and a former member of the Technical Panel.

IESO's Duru said staff are discussing with the panel when it should review market manuals.

"I'll be very pleased if I see this matter actually addressed," responded OPG's Vladislav Urukov, who represents market participant generators on the Technical Panel.

"If you remove the board oversight, and also were somehow able to make changes outside of Technical Panel oversight as well, I think that would be quite concerning. I think that there has to be some means for the participants to object and put counterarguments," he continued. "And to date, I haven't found that the baseline change process is robust enough and transparent enough and visible enough [to afford] such feedback.

"What the ISO hasn't really done to the extent that it ought to have is present analysis — technical analysis — that supports some of the values. … There has to be very robust, extensive analysis that participants can digest and challenge some of the assumptions … to be able to appreciate why the ISO is picking a value. You know, 'Why is it 100 and not 125?'"

Julien Wu, Evolugen | *Ontario Waterpower Association*

Urukov added that he is concerned that "if the discussion of the manuals goes in a way that isn't helpful, then there's no guarantee that this would actually go to the Technical Panel. And if it's only an education session, then there is no ability for participants to vote against or object."

IESO's Chung responded that to change the MMCP, "the ISO would have to go through a very robust stakeholder engagement [and] probably include consultants to provide analysis.

"We would not just change the value lightly. It would be a pretty big process."

Wu said he agreed the board should not be setting technical parameters.

But, he said, "there's a difference between saying that the board itself is not going to set the parameters [and] removing that obligation for the board to have some kind of governance review of the parameters."

To "remove any kind of board oversight — that takes away the ability of market participants outside of the consultation process to document any kind of concern or disagreement with the output values," Wu continued. "So maybe there is a middle way where the board itself doesn't have the authority to set — or responsibility to set — these values, but there's still a way, either through the [Technical Panel] or anywhere else, where serious concerns can still be [documented] by the market participants."

Less Discretion

Yamamoto said IESO should not expect stakeholders to give the grid operator the level of deference they did during the development of the MRP, saying the ISO should return "to a more robust forum."

"Saying, 'Well, this worked for MRP, and therefore we're going to design the going-forward processes as if we need all this discretion that we had in MRP' is a wrong-minded approach," he said.

IESO: Goal is to Increase Transparency

James Hunter, IESO's director of legal services, said the ISO is seeking to increase, not reduce, transparency and opportunities for input.

He noted that the legacy rules do not require that the parameter values be published in either the rules or the manuals and gives the ISO board power to change them without any stakeholder engagement.

Vladislav Urukov, Ontario Power Generation | *IESO*

"MRP introduced the constraint violation penalty values into the manuals for the first time in order to increase transparency around them," Hunter said. "MMCP and MORP have never been published. We're proposing to add them to the manuals. And the objective is not to request discretion from stakeholders. What we're trying to do is bring the establishment of these values into alignment with other technical parameters that are in the market rules.

"We want to increase transparency by publishing the manuals. … There's opportunity for stakeholder feedback that has not been the case historically."

But, he acknowledged, "I think what we've heard today is — in various forms — the suggestion that maybe there's a need or an opportunity for even more stakeholder involvement into establishing these values.

"I think we'll certainly talk about this [at the October Technical Panel meeting] as an instance of the more general question about how to determine where content is placed and rules and manuals."

Next Steps

Following the engagement session, ISO officials extended the deadline for written feedback on the proposal by one week to Sept. 30, as requested by Wu.

The Technical Panel will discuss the proposal Oct. 7, with a scheduled vote Nov. 11, preceding a board vote Dec. 8. ■

IESO Ups Capacity Target for Long Lead-time Resources

Need for Separate RFP Questioned

By Rich Heidorn Jr.

IESO has increased the capacity target for its planned solicitation for long lead-time (LLT) resources, even as it acknowledges questions about the need for the procurement.

The ISO plans to seek 600 to 800 MW of capacity from resources requiring at least five years of lead time, up from its proposed 600 MW, "to recognize the volume of system needs arising in 2035," officials *told* stakeholders at an *engagement session* Sept. 16. The energy target will be up to 1 TWh, unchanged from what the ISO outlined at its June 5 *engagement*.

IESO decided to pursue a separate 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. Energy proposals for LT2 are due Oct. 16, and capacity proposals are due Dec. 18. (See *IESO Officials Deny Favoring Gas Resources in Upcoming Procurement*.)

The ISO issued a request for information last fall to guide its design of the LLT solicitation and summarized its findings in an Aug. 29 report to the Ministry of Energy and Mines.

Requirements

To participate in the LLT procurement, resources must require a lead time of five or more years and have an operating life of 40 years, versus *20 years* in LT2.

Technologies for which IESO is less familiar — such as emerging long duration energy storage (LDES) — may need to prove they meet the lead-time requirement with an independent engineer report detailing the project scope, permitting path and supply chain constraints.

Although the LLT RFP is intended for new resources, IESO is considering including hydropower redevelopment projects — large-scale replacements of existing equipment that IESO said "would be similar in scope to a new build facility."

"Following redevelopment, the expected operational life of the facility would be comparable to that of a newly constructed facility," the ISO said.

Reservoir hydro projects (those with storage capability that are not pumped hydro) will be eligible to participate in the energy stream only because they would be unable to offer full contract capacity between 7 a.m. and 11 p.m. on business days, as required for capacity resources.

Pumped storage and other LDES resources will be eligible to submit in the capacity stream only.

IESO plans an engagement in October to discuss hydro repowering, expansions and upgrades of hydro and other resource types in its procurements.

Questioning the Need for LLT Procurement

Jonathan Cheszes, president of Compass Greenfield Development, questioned the need for the LLT solicitation, saying the eight- to 12-hour requirement for capacity resources is "functionally consistent" with that in the LT2 capacity procurement.

"If you need eight to 12 hours of capacity, then why not ask for eight to 12 hours of capacity? … Why limit what technologies can participate?" he asked.

IESO's Ben Weir said the LLT RFP is an

Why This Matters

Energy storage resources such as compressed air and pumped hydro require longer planning cycles than the four-year lead times for resources offering in IESO's pending Long Term 2 (LT2) procurement.

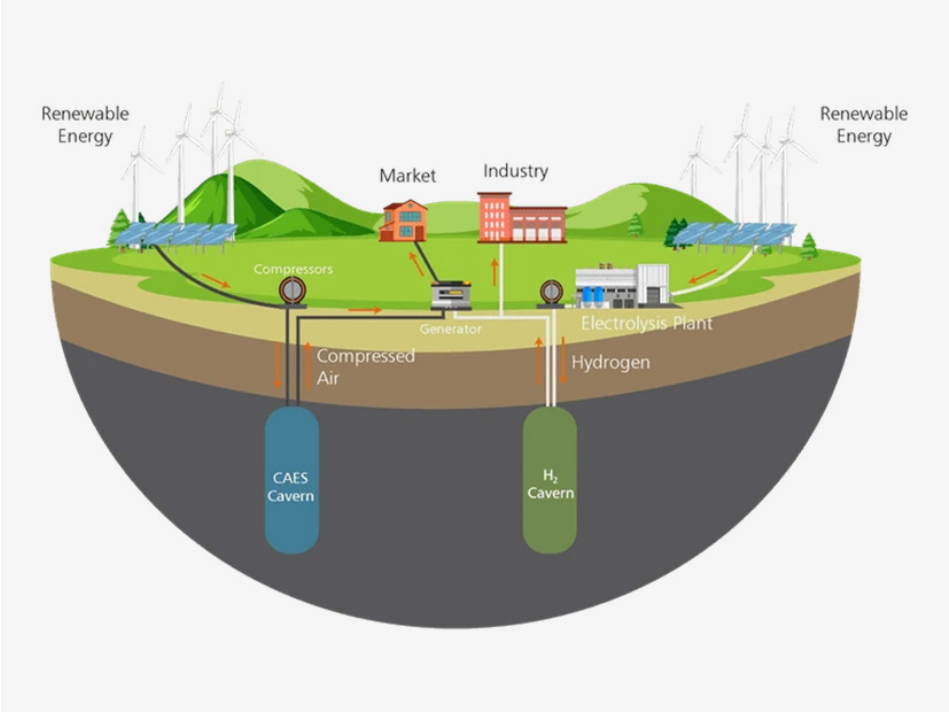


Diagram of a compressed air energy storage (CAES) system using renewable electricity to store compressed air in underground salt caverns, which can be combined with green hydrogen stored in co-located caverns to generate electricity. | *Corre Energy/Long Duration Energy Storage Council*

effort to procure resources with attributes — such as a 40-year life span — that can't compete in LT2.

"There's not much point in signing a 40-year contract with a battery, because it's not going to last 40 years … the way we intend to use it," Weir said.

Cheszes suggested the LLT procurement was premature.

"If you're going to get eight to 12 hours out of LT2 … maybe see what the pricing comes in at before" seeking a solicitation for LLT resources, he said.

"You raise an absolutely valid concern," responded Dave Barreca, IESO's supervisor of resource acquisition. "Please believe me that this is top of mind for us. … We are thinking very hard about ratepayer value and prices and how to manage that for this RFP, given that … the field of competition is quite narrow."

"Forty years [is] a long time," Cheszes responded. "Just imagine what batteries are going to cost 20 years from now. … And whatever [the] technology [will be, it] won't be lithium ion, right? It'll be something totally different. So, you know, locking in 40 years — there's some pluses, but there's a bunch of minuses as well."

Weir said ISO officials will hold engagements monthly for the rest of 2025 to develop the RFP, with proposals expected in the fourth quarter of 2026 and contract awards in the first half of 2027. The timing of the RFP and the target sizes will be finalized after receiving guidance from the ministry, Weir said.

Weir said IESO may accept a percentage of all proposals submitted — perhaps 80% — similar to what the ISO did in its second medium-term solicitation (MT2). (See *IESO Purchasing 3,000 MW of Energy and Capacity*.)

"This is just a way to maintain competitive tension if the numbers of proposals received are lower than we expect," he said.

Rated Criteria

IESO is seeking more information on potential projects in prime agricultural areas (PAAs) to inform how it sets its "rated criteria" — non-price factors used to evaluate proposals — for the procurement.

Some stakeholders said the ISO should not use rated criteria based on locations, such as for proposals located in northern regions or outside of PAAs.

IESO said its criteria will "be reflective of policy decisions made by the Ministry of Energy and Mines."

The ministry also will weigh in on whether IESO should offer price incentives — in addition to rated criteria points — for projects involving Indigenous communities.

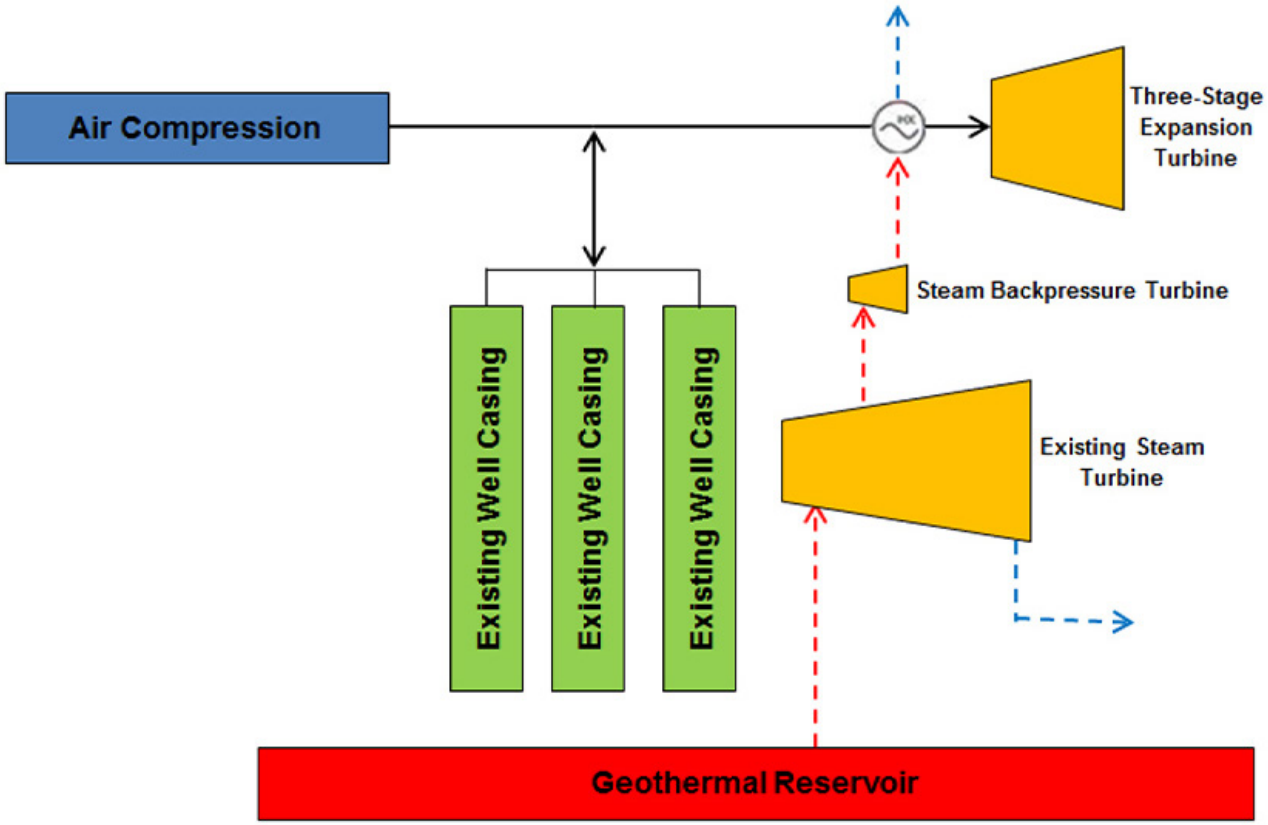
Round Trip Efficiency

IESO is considering minimum round-trip efficiencies (RTEs) — and incentives for exceeding them — because LDES are expected to have lower RTEs than battery storage.

Barreca said resources considering participating in the LLT RFP have offered a wide range of RTEs with a "middle" of about 60%. That "is quite different than what we've seen … in the lithium-ion batteries that we've procured" in the first long-term procurement, he said.

Outages

The ISO plans to use the same rules for planned outages as under LT2. Energy resources should incorporate planned outages into their imputed produc-



IESO's proposed solicitation for long lead-time resources would include long duration energy storage technologies such as compressed air energy storage. | *Pacific Northwest National Laboratory*

tion factors to avoid non-performance charges. Capacity resources will be permitted a planned outage of up to one month during April, May, October or November.

Resources will be permitted one long-term outage — a maximum of six months — during the second half of their contracts.

Environmental Attributes

IESO is considering allowing suppliers to retain the proceeds from sales of "environmental attributes" during the first 20 years of the contract, with the supplier sharing the attributes with IESO in the second 20 years.

Although suppliers are unlikely to place much value on the attributes for 2051-2070, Barreca said, "there is a good chance that there will be some value there" that could be recovered for ratepayers.

"We are certainly open to the alternative, which is that you do have forecasts for what those are going to be worth, and you are willing to put those values into your proposal prices," he added.

Defining LDES

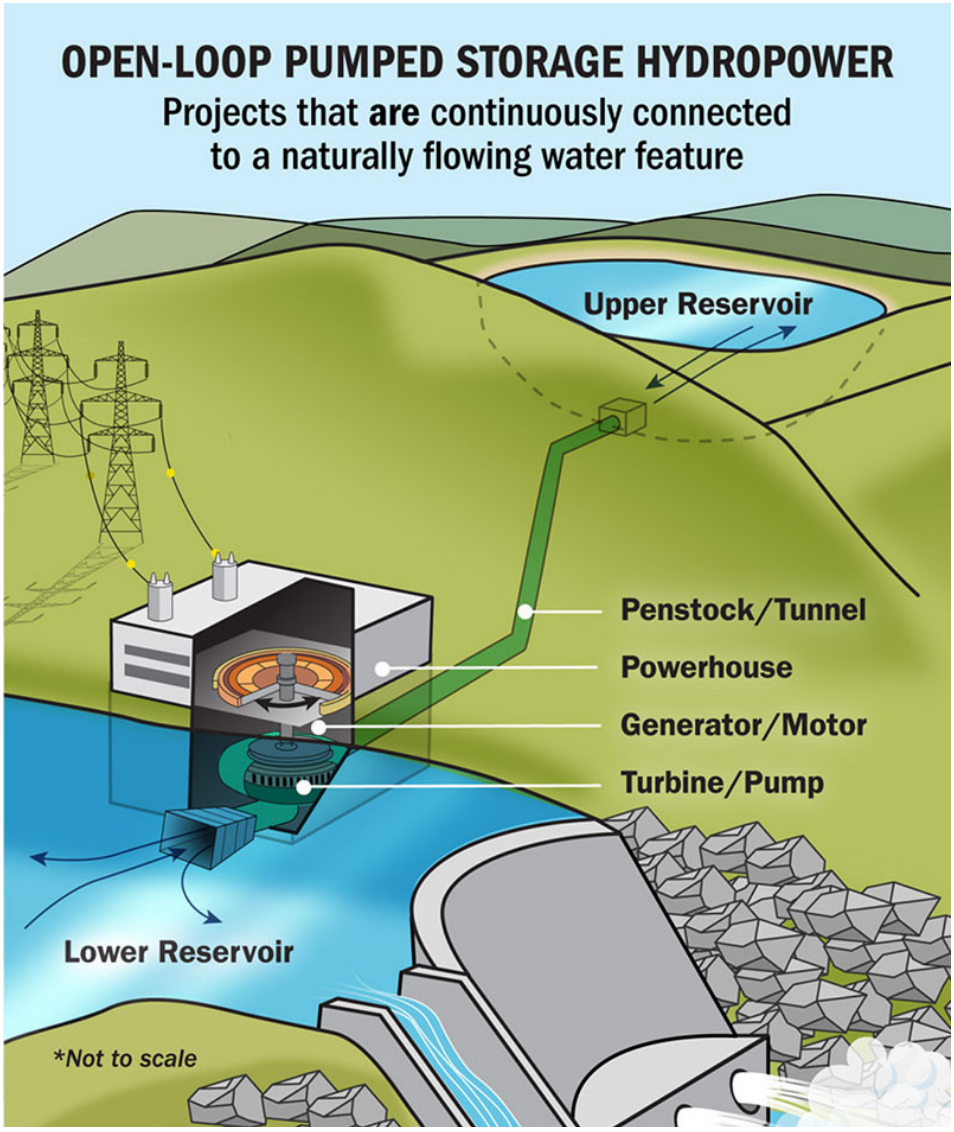
In addition to inviting participation by compressed air energy storage and pumped hydro storage, IESO will consider emerging technologies such as liquid air energy storage and compressed gas "that are able to demonstrate a sufficient level of technology readiness."

Stakeholders told IESO it should clarify its definition of commercially proven LDES technologies and allow participation from LDES technologies with a technology readiness level of eight or higher, indicating it is ready to move from development to commercialization, per the *U.S. Department of Energy*.

Although some stakeholders pushed IESO to increase the minimum duration requirement to 10 or 12 hours, the ISO said it expects participating LDES resources "to be in the eight- to 12-hour duration range, which can realize the most reliability benefits at this time."

Barreca said IESO's planning team is conducting research to understand the value of increasing the minimum duration.

"We'll need to make a call in terms of whether we think the extra value would be worth the extra price to make that a minimum requirement," he said. "There is more study required to go to the 24-hour or … multiday storage. That will be a different procurement."



Open-loop pumped storage hydropower systems connect a reservoir to naturally flowing water via a tunnel, using a pump to move water to higher elevations and a generator to create electricity. | DOE

Non-performance Charges

The ISO rejected requests that non-performance charges for energy producing resources be based on a five-year rolling average versus the three-year average used in LT2. The three-year average "allows for effective accounting of anomalies that may impact production, such as irregular weather patterns," IESO said.

Barreca said the ISO is sticking to a three-year average "primarily because this is a competitive RFP, not a standard offer program, and there are quite a number of variables that a proponent has to work with to find their optimal risk profile."

Price Escalation

IESO still is determining how it will escalate prices during the contract term.

Some potential suppliers said IESO should provide 100% inflation indexing from the contract date to the commercial operation date (COD) — similar to that in the LT2 RFP — and 60% indexing from COD until the contract end date.

Barreca said the 100% indexing in LT2 "was a direct response to the geopolitical environment at the time."

"We have a little bit of runway ahead of us to see what happens there," he added. "I think we are going to wait just a little bit longer and see how the world evolves between now and then." ■

Planners Pick $1.5B Underwater HVDC Line for Toronto's 'Third Supply'

By Rich Heidorn Jr.

IESO system planners on Sept. 25 recommended the construction of a $1.5 billion HVDC line to meet Toronto's growing energy needs, saying it would be more "future proof" than two cheaper options.

The approximately 40-mile, 900-MW line would run from the Darlington transmission station (TS) in Bowmanville to the Port Lands neighborhood, near Downtown Toronto, via Lake Ontario, requiring expansion of the Hearn switching station in the Port Lands area to add equipment.

"This option can deliver broader bulk system benefits, as it completely bypasses Cherrywood TS and Leaside TS," the ISO said in a *presentation* Sept. 25.

Toronto's electricity demand could increase 70% (reference case) to 100% (high electrification) by 2044 because of new housing and commercial development, data centers, and the electrification of heating and transportation.

As a result, electricity demand is expected to exceed the transmission capacity in 10 to 15 years, creating a "reliability need" by 2038 — or 2034 if the 550-MW gas-fired Portlands Energy Centre (PEC) ceases operations.

IESO's draft Integrated Regional Resource Plan (IRRP) recommends battery energy storage systems, upgrades to infrastructure and incremental electricity Demand Side Management (eDSM), including residential solar/storage systems, in addition to new transmission infrastructure.

"With or without the supply contributions from PEC, meeting the significant need identified for eastern Toronto due to the significant forecasted growth requires a large-scale wires solution," the ISO said.

Toronto is currently served by two high-voltage transmission corridors. The underwater line was one of three options planners considered for Toronto's "Third Supply," including an overland route from Cherrywood TS (Pickering) to Leaside TS in Toronto estimated at $800 million, and a hybrid of overland and underground segments from Cherrywood TS to the Port Lands, estimated at $900 million.

Why This Matters

Without a third major transmission source, Toronto's electricity demand is expected to exceed its transmission capacity in 10 to 15 years.

"We chose Bowmanville because here we can connect directly to the bulk power system, and it's conveniently near the lakeshore," said Steve Norrie, IESO supervisor of transmission planning. "We picked HVDC technology over the more traditional AC technology for its performance and economics over longer distances underwater. This option offers a new supply path that doesn't rely on Leaside TS, and it doesn't rely on any of the 230-kV networks at Cherrywood to inject more power downtown, which means that it can deliver broader benefits for the bulk system."

While all three options would meet East Toronto's growth needs into the 2040s, the underwater cable is "the most future-proof option, because it supports the forecasted demand the longest," Norrie said. "In fact, it will support the demand beyond 2044, so it pushes the need out past the end of the 20-year study in terms of system resilience."

Norrie said the HVDC line would help the city respond to "high-impact events," such as the extreme rainfall and flooding that resulted in the loss of supply in July 2024.

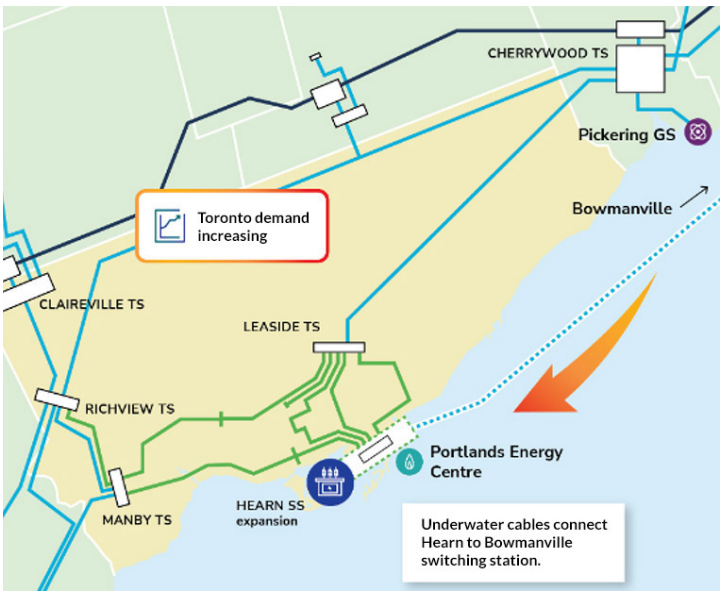
Toronto has experienced at least three one-in-100-years rainfall events over the last 20 years, and the last two disrupted power to more than 200,000 customers, "which is something that we really looked at this plan as an opportunity to address," Norrie said.

The overhead option doesn't change Toronto's reliance on the two existing transmission supplies, Norrie said. He said the hybrid would provide some resilience benefit for the downtown core, but the supply to Eastern Toronto would still be reliant on the path coming from Cherrywood.

"The underwater cable provides a new geographically separate and electrically separate supply path to the downtown. It reduces reliance both on Leaside and Cherrywood, plus it provides a means of backing up the other paths into Toronto in the event of a loss of supply," he said. "So this would be a significant improvement in system performance."

The ISO will consider written comments on the draft IRRP until Oct. 9.

"We will now be listening to feedback on this draft recommendation, and we will make our final recommendation at the end of October," IESO spokesman Michael Dodsworth told *RTO Insider*. ■



IESO planners recommended the construction of a $1.5 billion HVDC line to meet Toronto's growing energy needs, saying it would be more "future proof" than two cheaper options. | *IESO*

Escalating Conflict with Utilities Leads to Resignation of Top Conn. Regulator

PURA Chair Marissa Gillett Departing amid Escalating Conflict with Utilities

By Jon Lamson

The forthcoming resignation of Connecticut Public Utilities Regulatory Authority (PURA) Chair Marissa Gillett has created high-stakes questions around the state's adoption of a comprehensive performance-based regulation (PBR) framework, with three key votes set to occur just two days before Gillett is scheduled to step down.

Gillett, who has frequently drawn the ire of the state's investor-owned utilities, announced her *resignation* Sept. 19 after a prolonged pressure campaign by utilities and Connecticut Republicans, writing that "the escalation of disputes into a cycle of lawsuits and press statements pulls attention and resources away from what matters most: keeping rates just and reasonable, improving service and planning a resilient, reliable energy future."

The disputes have "exacted a real emotional toll both for me personally, as well as my family, and for my team," Gillett said, adding that "there is only so much that one individual can reasonably endure, or ask of their family, while doing their best to serve our state."

The day prior, on Sept. 18, Connecticut House Republican Leader Vincent Candelora *called for* an impeachment inquiry into whether Gillett lied during her February confirmation hearing about the existence of a directive requiring that "staff support for commissioners be directed through her."

Her resignation, which will take effect Oct. 10, comes as PURA works to finalize a set of major regulatory changes intended to better align utility incentives with customer benefits.

Gillett began her tenure as chair of PURA in 2019, making headlines by presiding over several rulings that significantly limited revenue increases for utilities or ordered revenue decreases.

With Gillett at the helm, PURA decreased the revenue requirements in rate cases for the Aquarion Water and a *pair* of Avangrid-owned gas utilities, significantly *limited* a proposed United Illuminating electric rate increase and issued major *fines* on the state's electric utilities for poor performance responding to Tropical Storm Isaias in 2020.

According to Gillett's critics, she fostered an unfavorable investment climate for utilities, hurting their credit ratings and disincentivizing investments in the state's grid. In recent months, Connecticut Republicans argued she overstepped the limits of her authority, and Eversource Energy and Avangrid alleged in lawsuits that Gillett held a personal bias against the companies.

Following the news of her resignation, Eversource's stock price spiked by about 8%. Equity analysts at Jefferies Research Services called the news a "clear positive" for the company, writing that Connecticut "has been one of the most challenging US regulatory jurisdictions for the past decade."

But according to her supporters, Gillett was extremely effective at pushing back against unjustified utility costs and rate increases, making her a target of utility companies.

Reacting to the news, David Pomerantz, executive director of the Energy and Policy Institute (EPI), a utility watchdog nonprofit, called Gillett "possibly the best utility regulator in the country," saying she "joins the long list of regulators who have attempted to lower rates and confront utility profits, and lost their jobs for it."

"I think Chair Gillett — more than any other utility regulator in the country, state or federal — was really enacting a reform agenda that could lower rates, and in doing so, was challenging the utilities and their investors on Wall Street to earn their profits in a different way," Pomerantz said.

PURA Chair Marissa Gillett | *Connecticut Executive and Legislative Nominations Committee*

Performance-based Regulation

Beyond specific ratemaking proceedings, much of Gillett's tenure has focused on PBR development in the state. The shift to PBR was initiated by the state legislature, which in 2020 directed PURA to develop a comprehensive PBR framework after Tropical Storm Isaias triggered extended power outages across the state.

PURA approved a more general set of goals, considerations and key outcomes for PBR in 2023 (*21-05-15*) and is nearing final votes on three follow-up dockets to establish specific performance metrics, revenue adjustment mechanisms and integrated distribution system planning requirements.

Throughout the process, utilities have frequently criticized PURA for failing to adequately consider their input, while environmental and consumer groups praised the agency for taking a collaborative approach. (See *The Rocky Road to Performance-based Regulation in Connecticut*.)

PURA issued draft decisions in each of the three second-phase dockets in July and August (*RE01*, *RE02*, *RE03*). Final decisions for each of the three dockets are scheduled for Oct. 8, two days before Gillett is set to resign.

Noah Berman, utility innovation program manager at the Acadia Center, said he would be "surprised to see a major pivot" in the PBR dockets from the proposed rulings.

"The question is whether the utilities decide to act in good faith on what is being established, or to put aside the years of work that have gone into these frameworks in favor of trying to delay and relitigate under a new chair," Berman said.

He expressed concern about a "post-resignation inquiry" that Avangrid submitted in the three PBR dockets, which argues Gillett "must have no further involvement" in all open dockets involving the company.

"Chairperson Gillett's multiple public statements evidencing bias and prejudgment of issues that she is required by law to adjudicate on an impartial basis are well known and are already the subject of pending litigation," Avangrid wrote. It added that, following the impeachment inquiry and Gillett's resignation, "if there was any doubt as to whether Chairperson Gillett could fairly adjudicate any of our matters, it is now extinguished."

Gillett's involvement in remaining proceedings, including the open PBR dockets, "will not only compound existing legal challenges to PURA's conduct but will result in new, unnecessary litigation," Avangrid wrote.

The company added it has "credible concerns about the conduct and bias of other high-ranking PURA personnel," and asked PURA to explain "what steps the agency will be taking to ensure that PURA staff who are unable to be objective about our matters are not hereafter involved in those matters."

Both Eversource and Avangrid declined to comment directly on Gillett's resignation, or the effects it will have on utility regulation in the state. The companies have denied all allegations that they attacked Gillett personally.

Clean energy and utility accountability advocates have been quick to push back on the allegations of impropriety or bias by Gillett and PURA staff.

"Nothing produced from the utility-led [Freedom of Information Act] campaign against Gillett showed anything but a regulator resolute in her commitment to ratepayers," Pomerantz of EPI argued.

He added that, in 2022, Avangrid's CEO *allegedly offered* to provide Gillett with opportunities for "international exposure" in advance of a rate case, while simultaneously threatening to pull investment in the state in the event of an unfavorable decision. Avangrid has denied any wrongdoing.

In an interview, Pomerantz said Gillett's replacement as chair, along with regulators selected to fill two additional open commissioner seats at PURA, will have a major influence on how PBR is ultimately used in the state.

"Performance-based regulation, generally speaking, is really only as good as the regulators that are there to implement it," Pomerantz said.

While PURA's PBR framework would be "best-in-class in the country," if the framework is ultimately approved, it will be "up to a new PURA and a new chair to decide how to implement that new regulatory model over time," he said.

Lindsay Griffin, northeast regulatory director for Vote Solar, said the "utilities' resistance to PBR is entirely predictable," noting that it would introduce revenue penalties for poor performance, along with bonuses for strong performance.

"With Chair Gillett's departure, implementing robust performance-based regulation becomes more critical than ever," Griffin said. "PBR represents the institutional safeguard that can continue protecting ratepayers even when regulatory leadership changes."

Broader Implications

Griffin also expressed concern about the ripple effects Gillett's resignation could have on utility regulation throughout the country.

"This resignation sends a chilling message: that sustained legal warfare and public pressure campaigns can drive exceptionally qualified public servants from office when they hold powerful interests accountable," Griffin said.

She emphasized the importance of "robust regulatory scrutiny," adding that utilities "should embrace regulatory oversight, not weaponize litigation to silence it."

Pomerantz offered a similar sentiment, adding that he thinks the "rest of the utility industry will be very happy to attempt to use [Gillett] as an example, to say to any other regulator, or potentially a governor, that 'we can do that to you too.'"

He said other regulators also appear to have been pushed out of their jobs after clashing with utility companies, citing Michigan Gov. Gretchen Whitmer's decision to *replace* Alessandra Carreon on the Michigan Public Service Commission with a political staffer who had worked for a former Michigan House speaker who took large campaign contributions from utility executives.

Instead of feeling intimidated by Gillett's resignation, Pomerantz expressed his hope that regulators across the country will have the opposite reaction.

"It would be really nice if more of the regulatory community took offense to what the utilities have done here in Connecticut and felt galvanized by it," Pomerantz said. "I don't know if that's happening or not." ■

Advocates Defend Energy Efficiency Programs in Massachusetts

By Jon Lamson

Climate and consumer advocates are calling on Massachusetts lawmakers to preserve the state's energy efficiency programs as legislators work to develop an energy affordability bill in response to high gas and electricity costs over the past winter.

Advocates have expressed concerns that lawmakers may roll back efficiency spending to provide short-term relief to ratepayers. They defended the state's Mass Save efficiency program at a *hearing* held by the legislature's Joint Committee on Telecommunications, Utilities and Energy (TUE) on Sept. 25.

While Massachusetts' energy efficiency programs frequently rank among the best in the country — with the state placing second on the American Council for an Energy-Efficient Economy's (ACEEE's) *2025 State Energy Efficiency Scorecard* — the programs have drawn some increased scrutiny over the past year amid increased affordability concerns.

Over the past winter, sustained lower-than-average temperatures drove high energy prices across New England. In Massachusetts, higher gas supply rates coincided with increased distribution rates, which were largely driven by investments in Mass Save and a state program to replace leaky gas pipes.

Following public pressure for immediate rate relief, the Massachusetts Department of Public Utilities in late February ordered $500 million in cuts to the Mass Save budget. The utility-administered program is funded through charges on gas and electricity rates, and it offers rebates and incentives for building insulation, efficient appliances and heat pumps.

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Why This Matters

Massachusetts Gov. Maura Healey and legislators are working to develop a wide-ranging energy affordability bill, which includes significant changes to the state's energy efficiency programs.

While the 2025/27 budget — totaling $4.5 billion after the cut — is still higher than the $4 billion for 2022/24, the reduction drew some criticism from efficiency advocates, who argued it would reduce the long-term benefits of the investment.

The Massachusetts Department of Energy Resources estimated that the original $5 billion investment would return $13.6 billion in overall *benefits*, including $5.4 billion in direct energy savings. The 2025 ACEEE scorecard estimated that Mass Save investments have *returned* $3.50 for every dollar invested since 2013.

Political battles over energy efficiency funding are not limited to Massachusetts; Rhode Island Energy has proposed to *cut* its program's funding by 18% in 2026 compared to 2025 levels.

Meanwhile, the federal One Big Beautiful Bill Act *eliminates* significant tax credits for HVAC equipment — including heat pumps, electrical upgrades and insulation — at the end of 2025.

At the TUE Committee hearing Sept. 25, advocates argued that additional efficiency spending must not be put on the chopping block as lawmakers look for near-term rate savings.

Amy Boyd Rabin, vice president of policy and regulatory affairs at the Environmental League of Massachusetts, advocated for legislation to "create a mechanism to fund energy efficiency and decarbonization efforts beyond our electric and gas bills, taking the burden of Mass Save off of ratepayers' backs, without hurting the programs or the benefits they can deliver for consumers and the climate."

She estimated that Mass Save "has reduced Massachusetts' energy use by 13.9 billion kWh annually, or 28% of current electricity sales. That's equivalent to the annual production of all our renewables in ISO-NE each year."

Boyd Rabin added that, since its inception, the program has provided "$40.3 billion in benefits" from $11.8 billion in spending, a 3.4-to-1 return on investment.

"No financial adviser on Earth would urge us to pull out of a fund returning $3.40 for each dollar you put in," Boyd Rabin said.

Kyle Murray, director of state program implementation at the Acadia Center, emphasized the regionwide wholesale markets price suppression benefits of these investments.

He pointed to the ISO-NE capacity scarcity event June 24, when locational marginal prices spiked to $1,110/MWh between 6 and 7 p.m., and highlighted an Acadia analysis estimating that demand reductions associated with behind-the-meter solar saved the region $19.4 million during the day. (See *Extreme Heat Triggers Capacity Deficiency in New England* and *Behind-the-meter Solar Shines in ISO-NE Capacity Deficiency Event*.)

"ISO-NE does not similarly track the impact of energy efficiency. However, make no mistake: But for those critical investments we have made in energy efficiency over the years, those price spikes would have been dramatically worse," Murray said.

Responding to public comments, Sen. Mike Barrett (D), TUE co-chair, spoke favorably about energy efficiency investments, noting that, by statute, Mass Save spending is justified only "when it's the least expensive alternative" to meeting power demand.

He expressed concern that, while the costs associated with Mass Save are outlined on electricity bills, the savings are not easily apparent to ratepayers, masking the program's benefits.

"Mass Save is not Robert Redford; Mass Save is a character actor that gets lost in the scene precisely because they're effective," Barrett said.

Rep. Mark Cusack (D), who is in his first year as the House co-chair of the TUE Committee, largely did not respond in substance to the public comments at the hearing, which were overwhelmingly supportive of preserving or expanding the state's energy efficiency and building decarbonization programs.

Rep. Jeffrey Turco (D) appeared more skeptical about efficiency investments, saying that "to the consumer, we keep hearing that we're saving $3.41 for every dollar invested, but the cost of electricity is going up every year, and it's by design."

Increasing the cost of electricity in the short term in pursuit of long-term benefits causes consumer frustration "because the utility keeps going up, and despite saying, 'Yes, we're saving you money,' the proof is not in the pudding on a monthly basis," Turco said.

In response, Murray said, "One of the most difficult challenges of energy efficiency is that it's difficult to prove a negative."

He stressed that while the value of efficiency can be hard to quantify precisely, "if we don't continue to do this, you're asking constituents in five, 10, 15, 20 years to bear significantly higher costs." ■

MISO: More Time Needed to Perform 8-year Resettlement of TOs' ROE

By Amanda Durish Cook

MISO says it needs more time to finish meting out refunds to transmission customers nearly a dozen years after a complaint was first raised to lower its transmission owners' base return on equity (*EL14-12, et al.*).

The RTO and TOs requested an extension until June 30, 2026, of the current Dec. 1 deadline to complete refunds under a FERC-ordered ROE in transmission rates.

In an October 2024 order, FERC set MISO's base ROE at 9.98%, down from the previous 10.02%. That figure is the latest in a complicated carousel of ROE percentages the commission has set in the last decade.

© RTO Insider

MISO transmission customers first complained in late 2013 that the 12.38% ROE in use since 2002 was excessive. A second complaint challenging the ROE followed in 2015; that complaint was dismissed as FERC set and reset ROEs from 2016 onward (10.32% beginning in 2016, 9.88% in 2019 and 10.02% in 2020).

In the 2024 ROE order, FERC upheld an original 15-month refund period from Nov. 12, 2013, to Feb. 11, 2015, while prolonging a second refund period from Sept. 28, 2016, through Oct. 17, 2024. The TOs are challenging the eight-year refund period. (See *MISO TOs Take ROE Battle to DC Circuit Court Again*.)

MISO said more time is necessary to complete the complicated resettlements and accurately disperse refunds with interest for the eight-year period.

The grid operator said, "The number of affected transmission owners, the number of months involved and the number of affected schedules have all increased." The affected TOs are up to 89, from 75, while the months needing resettlement are up to 181, from 110, it said.

"The tasks have been organized as efficiently as possible but involve 'thousands of files and communications,'" the RTO told FERC, quoting an attached affidavit from its manager of transmission settlements, Erin Peddicord. "Coordination must take place between MISO and its many TOs, 'with the exchange of hundreds of files between MISO and its transmission owners for every resettlement year [from] 2013 through Oct. 17, 2024.'"

Peddicord said that although the RTO has been making progress, the base ROE is "fundamental to MISO's transmission billing." She said FERC's changes impacted several revenue schedules and tariff attachments, which are used in part to develop zonal transmission rates, MISO's systemwide rates and compensation for the 2011 batch of Multi-Value Projects.

She added that transmission formula rates are not standardized in MISO, and TOs have different refund obligation dates, resulting in partial month settlements in some cases. She said the refunds are set to affect all TOs, whether they use historical, forward-looking or hybrid test years to calculate their annual transmission revenue requirements. ■

What's Next

FERC will decide if MISO and its transmission owners actually need an extra six months to make refunds following a change to the return on equity in transmission rates.

MISO Cuts Renewable Estimates in Tx Planning Scenarios

By Amanda Durish Cook

MISO has slashed earlier renewable energy estimates and boosted natural gas contributions in its transmission planning futures in a rethink brought on by the Trump administration.

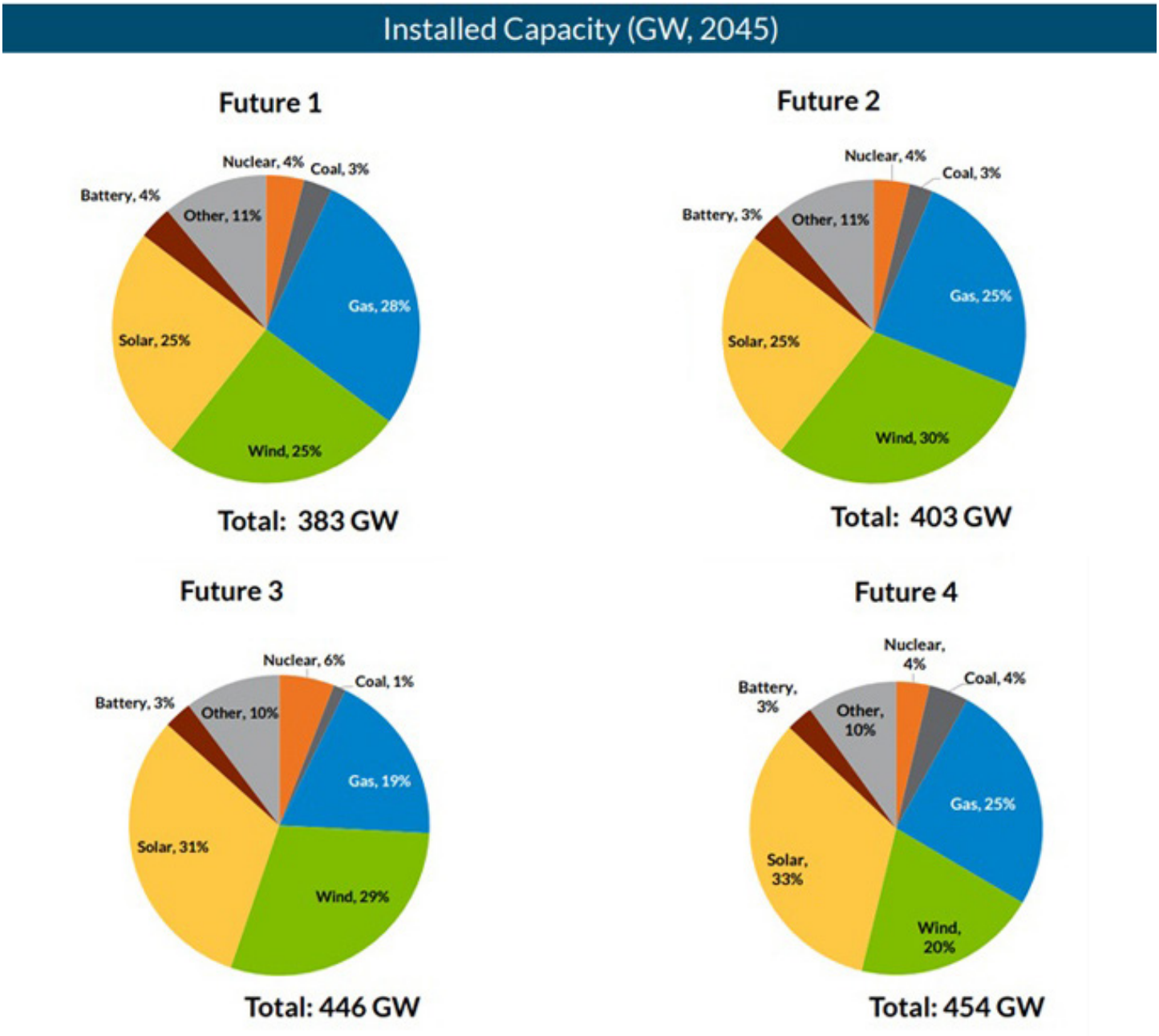
Director of Economic and Policy Planning Christina Drake told stakeholders that MISO took a "very hard pivot" to incorporate the One Big Beautiful Bill Act into its four, 20-year futures, which are used to plan long-range transmission.

Why This Matters

Future renewable energy estimates were pared down while gas generation gained momentum in the newest version of MISO's long-term transmission planning scenarios.

MISO was on its way to completing the futures and publishing capacity expansion estimates when the bill was passed in July. Staff have added months to the process and expect to deliver final futures sometime in early 2026. (See *MISO Seeking Realistic Gen Buildout for Tx Planning Futures*.)

"There is quite a bit of reduction in some of the renewable buildout," Drake said



MISO's preliminary installed capacity estimates in its four transmission planning futures | *MISO*

before a Sept. 24 stakeholder teleconference. She also said MISO is reflecting increases in natural gas buildout in its members' resource planning.

MISO Senior Manager of Policy and Regulatory Planning RaeLynn Asah said gas now represents a much higher share of the capacity expansion than when MISO last updated its futures in 2022.

MISO's preliminary capacity expansion estimates by 2045 now include:

- For Future 1, a total of 383 GW in installed capacity derived from 28% gas, 25% solar, 25% wind, 11% other, 4% battery, 4% nuclear and 3% coal at 911 TWh of output, with 224 GW built between now and 2045.
- For Future 2, a total of 403 GW in installed capacity from 25% gas, 25% solar, 30% wind, 11% other, 3% battery, 4% nuclear and 3% coal at 1,075 TWh of output, with 254 GW constructed in 20 years.
- For Future 3, a total of 446 GW from 19% gas, 31% solar, 29% wind, 10% other, 3% battery, 6% nuclear and 1% coal at 1,253 TWh of output, with 318 GW built between now and 2045.
- For Future 4, a total of 454 GW from 25% gas, 33% solar, 20% wind, 10% other, 3% battery, 4% nuclear and 4% coal at 1,079 TWh of output, with 281 GW constructed.

MISO's futures are fashioned through a "fast, faster, fastest" methodology for fleet change and demand in Futures 1-3. Future 4 — new for 2026 — anticipates continued supply chain hindrances and only includes member-announced generation retirements. Unlike the other futures, it doesn't assume age-based retirements of thermal generators, resulting in about 23 GW of additional thermal generation compared to the other three futures.

MISO's members have announced intentions to build 171 GW in resources by 2045. MISO's modeling had to add the most supplemental resources to Future 3, where only 58% of capacity needs would be met using the 171 GW.

The RTO's fleet prediction in 2022 under Future 2 for 2042 was 471 GW of installed capacity, consisting of 14% gas, 24% solar, 34% wind, 11% other, 9% hybrid resources, 6% standalone batteries, 2% nuclear and 2% coal. That future formed the basis for MISO's nearly $22 billion long-range transmission plan for MISO Midwest.

MISO said sustainability goals from states and members, not federal incentives, would drive future capacity expansion.

Drake said as it stands across all futures, milestone goals from 2026 to 2028 in Illinois' Climate and Equitable Jobs Act and New Orleans' renewable portfolio standard were unattainable. MISO said lead times to build units made the goals infeasible in the near term. Illinois has set out to achieve 100% carbon-free energy by 2050, with interim targets of 40% renewable energy by 2030 and 50% by 2040. New Orleans, on the other hand, is attempting to achieve net carbon neutrality by 2040 and 100% carbon-free electric generation by 2050.

MISO's Environmental Sector requested a sensitivity study on the futures where natural gas prices rise, prompting an energy storage expansion.

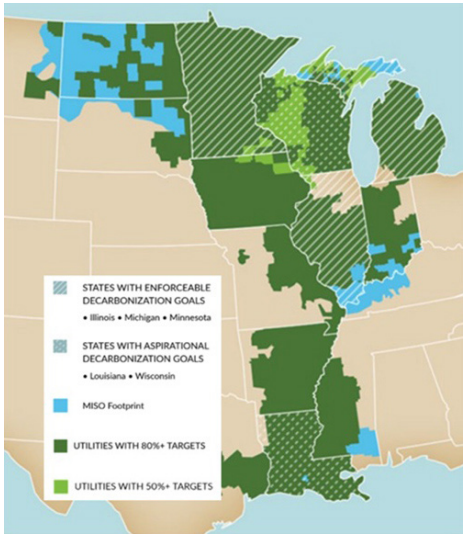
Sustainable FERC Project's Natalie McIntire said she wondered whether the futures for use in scenario-based planning should be more "diverse" from one another and contemplate a wider range of possibilities. She said MISO should contemplate variables like rising gas prices and falling battery prices, along with the possibility of a reinstatement of tax credits for renewables.

Drake said MISO will check in with stakeholders once futures are more developed. She added that MISO planners have asked themselves the same questions.

"If we get to the end of this process and we don't have broad bookends, we will revisit," Drake promised. She stressed that MISO's numbers aren't final yet.

Drake said MISO is halfway through the recalibration of its futures. She said initially, removal of tax credits for wind and solar resulted in MISO's model building a hypothetical 100 GW within a single year to take advantage of the fading perks. Drake said after MISO staff "laughed" at the results, they removed the possibility for renewable production and investment tax credits for generation not already in the queue.

"The rationale for that is if it's not already in queue … it won't be in the ground and ready to go by 2028," she said.



Decarbonization goals across MISO states | *MISO*

Drake also said MISO must complete generation siting and large load siting for use in its transmission models alongside completing energy adequacy assessments to develop the futures. She said MISO would discuss the locations of large loads in the footprint in November.

MISO Senior Vice President of Planning and Operations Jennifer Curran said members recently have swapped lower accredited renewables for higher accredited dispatchable plants in their plans. She also noted that the U.S. Department of Energy has become "directly involved" in resource retirements, issuing a second extension of Consumers Energy's J.H. Campbell coal plant in Michigan.

"There has been a lot of activity on the federal front," Curran acknowledged at a Sept. 17 Advisory Committee meeting in Detroit, part of MISO's quarterly Board Week.

Curran said it became apparent that a repurposing of futures was necessary in July, when the early expiration of tax incentives became clear.

"We're putting a lot of eggs in the gas development basket," Clean Grid Alliance's Beth Soholt said in response to MISO's remarks, asking whether the RTO would factor in pipeline capacity issues and fuel availability limits.

Curran said MISO would try to capture the fuel availability associated with "explosion" in gas development and pipeline constraints in the resource's capacity accreditation. ■

Entergy Uses Ark. Energy Emergency Laws to Justify Gas Plant Plans

By Amanda Durish Cook

Entergy Arkansas says a recently enacted Arkansas law strengthens the case for its plan to build a new natural gas plant, a proposal that has drawn criticism from the state's attorney general and regulatory staff.

The utility applied to build the 754-MW Jefferson Power Station near Redfield, Ark., in early August, but staff with the Arkansas Public Service Commission and state attorney general's office asked the PSC in early September to deny the utility's proposal.

The two agencies cited underdeveloped studies, a neglected analysis of alternatives, uncertain costs and a lack of ratepayer protections (*25-047-U*). The proposed plant would be adjacent to the utility's White Bluff coal-fired power station, which is slated for retirement in 2028. Entergy envisions the gas plant would begin operation in 2029.

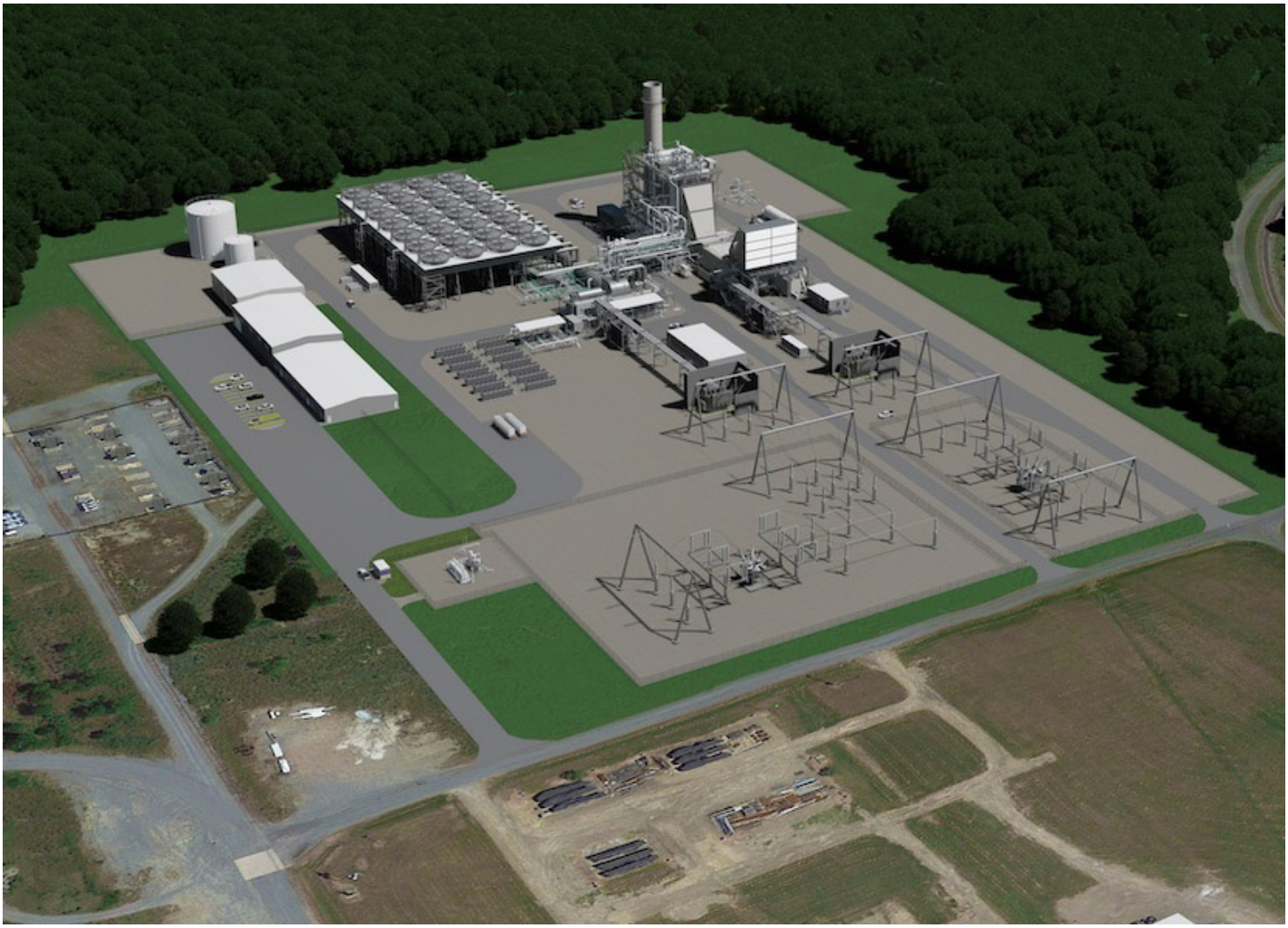
In a Sept. 19 round of filings, Entergy Arkansas' rebuttal to state officials invoked acts 373 and 940, both passed by the Arkansas legislature in 2025.

Act 373, also known as the Generating Arkansas Jobs Act, makes it easier for electric utilities to finance new construction projects, while Act 940 adds review for retiring dispatchable generation and emphasizes a reliable, adequate and affordable power supply with the PSC fostering development. Both laws contain emergency clauses.

Why This Matters

Entergy Arkansas is steadfast in arguing that the new Jefferson Power Station is the best route to meeting capacity needs in 2030 despite disapproval from regulatory staff and the state's attorney general.

John Bethel, director of public affairs at Entergy Arkansas, said the Jefferson Power Station is exactly the type of



Entergy Arkansas' rendering of its proposed Jefferson Power Station | *Entergy Arkansas*

resource the state legislature envisioned and will be "critically important" as the utility's largest gas plant.

Bethel said the plant is "undoubtedly necessary for [Entergy Arkansas'] long-term ability to provide adequate supplies of reliable, affordable and dispatchable power to all customers."

In accordance with the two laws, he said, Entergy is prioritizing speed to market for new, dispatchable generation to serve economic development. He added that the utility was able to secure in-demand components for the plant "at a time when it is very difficult to procure new gas resources of this kind."

Entergy hasn't publicly disclosed the cost of the plant, citing an incomplete engineering, procurement and construction agreement. The utility has redacted total price estimates in public filings.

Entergy has also proposed that the Cypress Solar project — consisting of a 600-MW solar array and a 350-MW battery energy storage system — be paired with the natural gas project. The utility estimates that both projects would add $4.87 to an average residential customer's monthly bill.

Kandice Fielder, Entergy Arkansas' senior manager of resource planning, said no one has disputed the utility's need for the new capacity. She said Entergy's analyses show that adding the gas plant would "yield substantial net benefits to customers" by using land the utility already owns and White Bluff's interconnection rights.

Fielder said more than 80% of project costs would originate from two competitive solicitations Entergy Arkansas conducted.

'Methodological Flaws'

Jeffrey Bower, a consultant with Daymark, in early September filed testimony on behalf of the Arkansas PSC contending that Entergy failed to meet the commission's resource planning guidelines because it didn't compare the self-built resource to "market opportunities." He said also that Entergy didn't propose any cost containment or consumer protections or compare the new gas plant with a conversion of White Bluff to burn an alternative fuel.

"The attempts by the company to compare the project to alternative options are either inadequate or contain methodological flaws," Bower said. He noted that Entergy appeared to assume EPA regulations eventually requiring carbon capture technology would be repealed even though they're not yet dismantled.

Bower asked the PSC to order Entergy to supplement the application with additional analysis and protections for ratepayers.

But Bethel said Bower's stance "must be revisited" given that the legislature has charged the Arkansas PSC with eliminating obstacles to developing a "diverse" generation fleet that includes "cost-effective dispatchable electric generation."

Bethel also said Entergy may additionally consider converting White Bluff's coal units into a natural gas peaker plant. However, that conversion would not be enough of a substitute for the Jefferson Power Station. He said ordering a comparison of the coal plant conversion to the new gas plant "is a red herring because the resources are not directly comparable."

Arkansas Attorney General Tim Griffin similarly opposed Entergy's proposal. Scott Norwood, an energy consultant who filed testimony on behalf of Griffin's office, said Entergy hasn't shown the Jefferson plan would come in at a reasonable cost or "is the best available resource for meeting [Entergy's] system capacity need in 2030."

Norwood said also that the utility did not explore the alternative of converting White Bluff from coal to gas, which "would have a far lower cost." He added that Entergy's other economic analyses of the plant are "based on unreasonable cost assumptions that serve to overstate the benefits."

Meanwhile, in its Sept. 22 report, *The Dirty Truth*, the Sierra Club faulted Entergy for overcommitting to natural gas and backpedaling on sustainability goals.

Entergy in 2019 committed to reducing its emissions by 50% by 2030, followed by a 2021 commitment to 50% carbon-free generating capacity by 2030. However, in late 2024, the utility said its capacity goal would be "delayed for an as-yet undetermined period beyond 2030" and said its emissions timeline could slip based on growing demand. Entergy said it recognized that "some of our new generation resources will be cleaner but not carbon-free."

The utility said it remains committed to its long-term carbon target of net-zero emissions by 2050.

The PSC has scheduled a public hearing for the Jefferson plant Oct. 30 and expects to issue a final order near the end of January 2026. ■

NYISO Dogged by Uncertainty in Comprehensive Reliability Plan

Draft Includes Range of Scenarios, but Most Show Declining Reserve Margins

By Vincent Gabrielle

NYISO's draft 2025-2034 Comprehensive Reliability *Plan*, released Sept. 25, shows a wide range of possible scenarios for resource adequacy in New York, with the most negative outlook showing a deficit of up to 10 GW by 2034.

The ISO is contending with aging generation, climate change causing heightened weather variability, generator and transmission project delays, and large load additions.

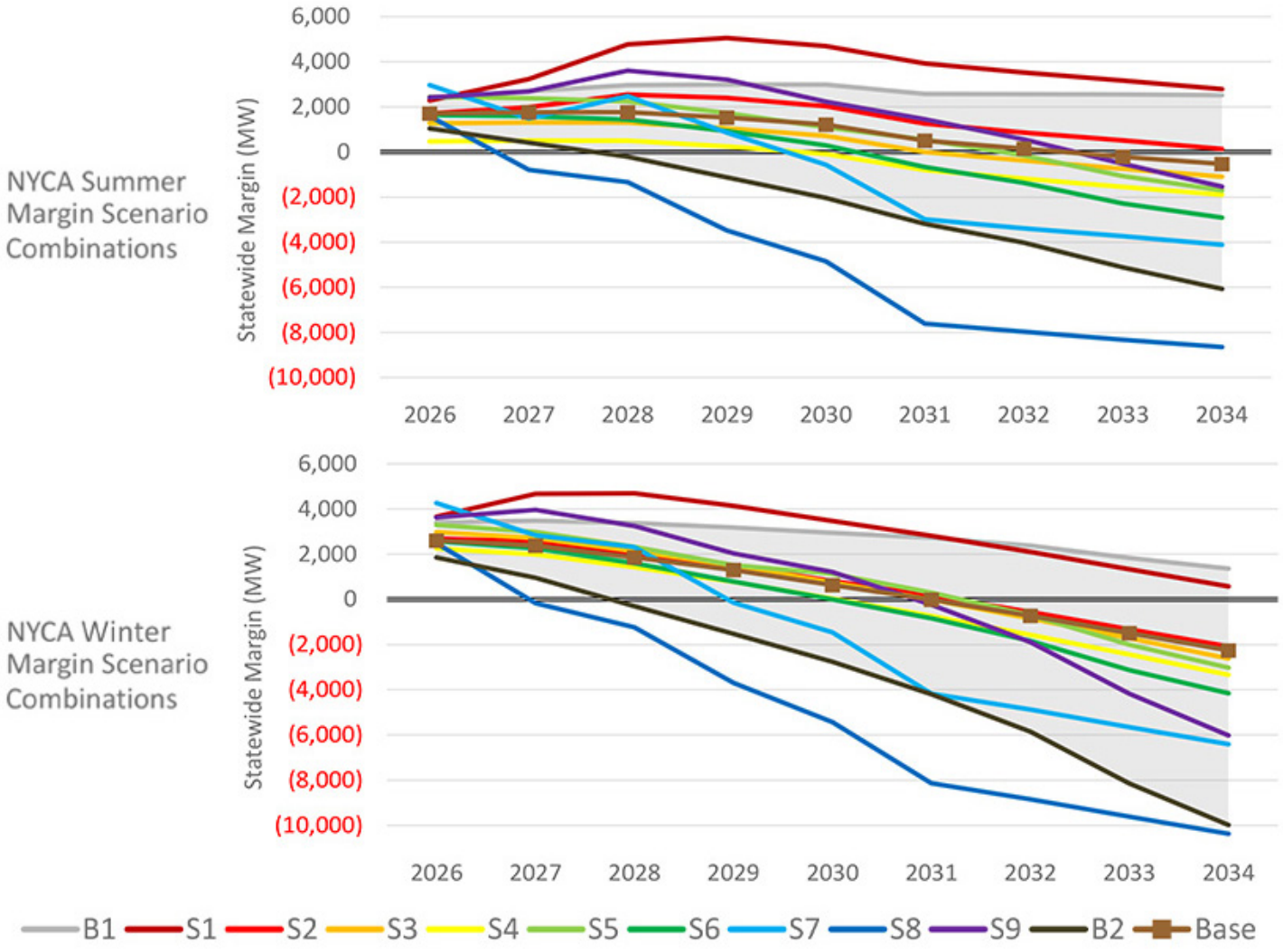
"While each of these factors presents its own set of risks, their combined effects can be far more consequential," the draft says. "A single uncertainty may reduce reliability margins, but multiple uncertainties occurring together — such as higher demand coinciding with delayed transmission projects or overreliance on aging generation — can result in critical supply shortfalls."

Why This Matters

Uncertainties in long-term climate, demand growth, and generation and transmission buildouts are compounding to make NYISO's Comprehensive Reliability Plan challenging.

"The one thing I hope you take away from this presentation is that 'uncertainty' is the key theme of the CRP," Ross Altman, NYISO senior manager of reliability planning, told the Transmission Planning Advisory Subcommittee. "It's quite critical in how we view reliability with such shrinking margins that we are seeing."

To illustrate this, Altman pointed to the 2024 Reliability Needs Assessment that identified a reliability need in New York City for about 97 MW by 2033 because



These graphs show how different scenario assumptions impact system reliability margins beyond the assumed baseline system condition until 2034. | *NYISO*

of transmission security problems. A change in the demand forecast modeling eliminated the need. (See *NYISO Cancels 2033 Reliability Need for NYC*.)

"That's not a very comfortable place to be, but it did resolve the reliability violation," Altman said.

The draft evaluates each identified risk's impact on the statewide reliability margin before examining several combinations of the best- and worst-case scenarios from each. It includes 11 scenarios forecasting different system conditions and combinations of demand, new generation, retirement, transmission upgrades and weather conditions. Of these scenarios, only two saw summer and winter sufficiency by 2034. One of them is a lower-boundary scenario where load growth follows the Lower Demand forecast in the 2025 Gold Book. The other is a scenario in which all generation in the queue is constructed on schedule, and all battery storage is able to be discharged at maximum during peak hours.

"Most of the combinations of scenarios show decreasing margins through 2034, with the range of future margins growing over time. The most optimistic scenario combinations show positive margins by 2034 that are roughly equivalent to today's margins in the positive 2,000-MW range," the draft says. "On the other hand, the most pessimistic scenario combinations show deficiencies of up to 10,000 MW by 2034.

"While a negative statewide system margin is not, on its own, a violation of a reliability criterion, it is a leading indicator of the inability to securely meet system load under applicable normal system conditions."

"We're really concerned about this whole analysis," responded Kevin Lang, a lawyer from Couch White representing New York City. He said the margins that determined reliability needs were extremely small. While he said he appreciated the various scenarios and sensitivities included in the draft, he argued that NYISO had a responsibility to explain all of it to the public. The tight margins and differences in outcomes because of different assumptions made "material differences" to whether action had to be taken now.

"This idea that we look at one baseline and say, 'There's no reliability need, no need to do anything' — I think we need to reconsider that," Lang said. "Because many of your scenarios suggest that there is something."

Altman agreed and said the ISO should not focus on a single determination or set of assumptions when there is a wide range of possibilities for how the system could evolve. The final CRP's recommendations would make that clear, he said.

One stakeholder said he hoped the ISO would emphasize that the uncertainties go in both directions so the public would not view forecasting uncertainties in "an overly negative light."

The draft shows several blank pages and notes about what will be included in the final report.

"There's no way we're voting on this in October," said Doreen Saia, chair of the environmental law practice at Greenberg Traurig. "We cannot rush this. We just got this information. It's a lot of information. It's going to be critical to formulate it correctly and responsibly."

She pointed out that the draft did not include an executive summary, conclusion or recommendations yet. ■

Latest NY Renewables Solicitation a Race Against Time

State Seeks to Fill out Pipeline Before Federal Tax Credits Sunset

By John Cropley

New York has launched a *renewable energy solicitation* enlisting multiple agencies to expedite the process and get projects approved while they still can qualify for federal tax credits.

Developers with shovel-ready projects are the target audience in the new request for proposals. Gov. Kathy Hochul announced Sept. 26 that she is directing state agencies to work together to advance as many of them as possible as quickly as possible. The whole-of-government approach is intended to streamline permitting, interconnection, financing and contracting processes.

Applications are due Oct. 21, and final proposals are due Dec. 4. Initial award notifications are expected in February 2026.

This time frame leaves a narrow margin before a key Trump-era deadline for solar and wind projects: They must begin construction by July 3, 2026, to qualify for 45Y and 48E production and investment credits.

The New York State Energy Research and Development Authority, which manages the state's renewables solicitations, said this ninth large-scale, land-based RFP is expected to result in a $5 billion investment in projects with a combined capacity of at least 2 GW.

A NYSERDA spokesperson could not estimate how many projects are in so advanced a stage of planning that they could begin construction within a few months of a contract award. But many New York projects were paused during the financial turmoil that hit the renewable energy sector in 2023.

A state *database of large-scale renewable projects* over the past two decades provides the tally: Of the 311 projects listed through Aug. 28, 112 are completed or operational, and their combined rating is only 2.78 GW. The 65 projects under development would have a capacity of 8.21 GW. The 134 projects listed as canceled could have produced 17.52 GW.

Wind turbines dot a ridgeline in upstate New York. | *Shutterstock*

The disparity is not as great as it seems: Some of the projects listed as "canceled" were not canceled at all; their contracts were. The projects themselves were rebid in later solicitations, won new contracts and are now "under development."

Meanwhile, NYSERDA cites yet another number: 102 projects totaling 9.7 GW in operation or under development.

But even if the aggregate totals of the numbers are mismatched, the numbers themselves paint a picture of a renewable energy campaign that has had more than its share of setbacks.

The latest setback is the re-election of President Donald Trump, with his embrace of fossil fuels and his active efforts to thwart renewables.

New York is not onboard with this, Hochul *said in a news release*: "While the federal government takes us backward on energy policy, New York will not be thwarted in its commitment to clean energy."

But the loss of 45Y and 48E may have a greater impact than the rhetoric on either side of the fossil/renewable debate, as it will make an already expensive state more costly for renewables development. So the state is racing to beat the clock and take advantage of the credits.

Marguerite Wells, executive director of the Alliance for Clean Energy New York, told *RTO Insider* the organization is happy with the solicitation and the details of it. Her members have been racing to buy equipment and looking for ways to start work, both in hopes of beating the July 3 cutoff date for tax credits.

Wells said it was a bold move by Hochul to order a whole-of-government effort to fill the state's renewable energy pipeline, as it might raise the Trump administration's ire with her and the state.

Why This Matters

Renewable energy developers have eight months to start construction in order to qualify for lucrative federal tax credits.

But it was a necessary move, Wells said, because while the state agencies central to energy development have been working as a team to expedite renewables, some of the adjoining agencies have been focusing on their own core responsibilities rather than their limited role with renewables, which has slowed down the regulatory process.

"And having it be not just something that agencies are quietly doing but something she is exhorting them to do," Wells said, "actually really helps the private sector also encourage their funders to keep investing, because there's a lot of people who are skittish about the U.S. market broadly and New York specifically."

Wells confirmed that there has been a significant attrition rate for developers recently: Roughly a third of projects in the NYISO interconnection queue have dropped out in the past six months.

But this is not entirely from the chilling effect the Trump administration's policy changes have had on the industry, she said. It is more from the changes NYISO implemented for FERC Order 2023 and its own parallel reforms, Wells said, which penalize developers for parking immature projects in the queue before they are ready to commit to construction.

Many have dropped out for that reason, she said, although the reason some are not ready to commit is Trump's anti-renewables stance.

"Some of the withdrawals are delays, deferments if you will, and some of the withdrawals are genuine cancellations," Wells said. "I couldn't say what percentage are which, because I truly don't know, but I think it's some of each." ■

PJM Members Confirm 2 Board Nominees; States Call for Governance Overhaul

By Devin Leith-Yessian

The PJM Members Committee overwhelmingly voted to appoint Robert Ethier, a former ISO-NE executive, and Le Xie, faculty co-director of the Power and AI Initiative at the Harvard School of Engineering and Applied Sciences, to fill two vacant positions on the RTO's Board of Managers.

Robert Ethier | *ISO-NE*

Both nominees were elected with 97% sector-weighted support during the MC's Sept. 25 meeting. (See *Robert Ethier, Le Xie Nominated for PJM Board*.)

Their ascension brings the board back to its full 10-member roster after the membership declined to re-elect Chair Mark Takahashi and Terry Blackwell during the 2025 Annual Meeting in May, citing transparency concerns and frustration with the capacity market design. (See *PJM Stakeholders Reaffirm Board Election Results*.)

In the weeks leading up to the election, several governors of PJM member states requested that PJM's Nominating Committee consider naming former FERC Commissioners Mark Christie and Allison Clements to be considered for the board. During a multistate technical conference on Sept. 22, Virginia Gov. Glenn Youngkin called for PJM to reopen the nomination process. (See *Governors Call for More State Authority in PJM*.)

Prior to the MC vote, Philip Sussler, of the Maryland Office of People's Counsel, said PJM needs deep governance reform, and holding an election on board candidates without accompanying statements from the RTO about how it will change its path is disappointing.

Following the election, Xie told stakeholders that he aims to begin his tenure with a comprehensive listening tour across the region. He said PJM is facing complex, urgent challenges that will require the membership to think about what unites them.

Xie began teaching at Harvard in 2024, before which he was a professor at Texas A&M University starting in 2010. He previously held roles at the Massachusetts Institute of Technology and the University of California, Berkeley. He is also a fellow and distinguished lecturer at the Institute of Electrical and Electronics Engineers and has served as an editor for the group's *Transactions on Power Systems* journal.

Le Xie | *Harvard John A. Paulson School Of Engineering And Applied Sciences*

During his more than 24 years at ISO-NE, Ethier filled three vice president positions — system planning, market operations and market development — between 2008 and 2024. He is now a principal at Stickney Brook Consulting, based in Florence, Mass.

Technical Conference Calls for Overhaul of PJM Governance

Headlined by governors calling for a greater role for the states in PJM decision-making, panelists participating in the multistate technical conference debated the future of the RTO's governance structure and whether it is prepared to rise to the challenge of accelerating data center load.

Former FERC Chair Mark Christie said a crisis of confidence should be apparent when both the governors of Pennsylvania and Virginia speak about the need to either reimagine PJM or a future outside of it. The issue is not economic or technical, he said, nor does it lie with the experts at Valley Forge, but a problem of governance.

PJM started as a power pool, then morphed into a system operator focused on coordinating power flows; over time it has been empowered to take a more proactive role in planning resource adequacy as well. Christie said that has put it in the position of becoming a policy-making body when it determines how to allocate transmission costs and how it integrates the load forecast into the variable resource requirement curve that sets capacity prices.

Legislation over the Transource Independence Energy Connection transmission project underscores that point, he said, with the courts finding that the Pennsylvania Public Utility Commission violated the Constitution's Supremacy Clause in denying permits for the project. If states cannot make their own determinations on the need for transmission within their borders, he said, it underlines the governors' message that the states need more of a role in PJM decision-making.

"The states in PJM simply do not have a substantive role in PJM governance," he said.

He cautioned that his message isn't that state legislatures should be running PJM; it was to recognize that the question of how to address the interconnection of large loads and the associated costs is a technical and policy question. At a minimum, PJM states should have the same Federal Power Act Section 205 filing rights as member states of SPP and MISO, he said.

Joshua Macey, associate professor at Yale Law School, said granting Section 205 filing rights to the states is one of the most powerful governance changes that could be made. He said FERC defers to the entity filing a tariff change under Section 205 so long as it falls within a zone of reasonableness, while the bar for making changes under FPA Section 206 is much higher.

He said filing rights are not the end of the conversation between PJM and the states, who hold their own negotiating power through their ability to liquidate and restructure utilities to no longer be part of an RTO. He said there is a risk in taking too much autonomy away from PJM, which does hold deep expertise on technical issues. He said there are often actuarily correct cost allocation methodologies that have not been adopted because of political fighting.

During a "fireside chat" with Clements during the conference, PJM CEO Manu Asthana said the RTO does not hold the unilateral power to grant the states Section 205 filing rights; that would have to be endorsed by the MC and approved by


Manu Asthana, PJM CEO | © RTO Insider

FERC. He said governance reform is a conversation worth having, but there should be a parallel focus on the actual rule changes that are needed to address the resource adequacy problem in front of PJM.

Panelists also debated whether states should be granted voting rights in PJM's stakeholder process, with some arguing it would grant them both a voice and skin in the game.

Macey argued that PJM's stakeholder process favors incumbent asset owners, through dominance of the five membership sectors at the MC and holding even more power in the lower committees where votes are also allowed for affiliates.

Stacey Burbure, vice president of FERC and RTO strategy and policy for American Electric Power, said her company owns more than a quarter of the transmission in PJM, but holds only 2% of the votes.

Vincent Duane, principal at Copper Monarch and former general counsel for PJM, said the RTO is already ungovernable, and adding more votes to an already crowded body would likely leave the states disappointed. Instead, he said the focus should be on developing strong executive decision-making. He said the transmission owners should have a substantial role because of their place at the intersection of private capital and accountability to their states.

During his time at PJM, he said he regularly received questions from board members about who they owed their fiduciary duties to, and he found it difficult to give a specific answer. Until that can clearly be determined, along with the question of who manages the stakeholder process, he argued governance should take a back seat.

Dan Scripps, chair of the Michigan Public Service Commission, said MISO's requirement that one seat on its Nominating Committee be appointed by its member states allows them to have a seat at the table, rather than criticize the results from the sidelines.

"If you're locked out, you end up throwing rocks from outside," he said.

Maryland Del. Lorig Charkoudian said legislators and public utility commissions are charged with managing the resource mix in each state, but their efforts can be undermined by PJM decisions, which are made through an opaque stakeholder process. She said the primary cause of instability in PJM's market has been an interconnection queue unable to keep up with the pace of new requests. Now that PJM has put reforms in place to speed processing those requests, she argued the blame should not be shifted to state clean energy efforts, but to federal policies creating barriers to developing wind and solar generation.

Without more confidence that the transmission projects planned by PJM are truly necessary for reliability, she said it will be a hard sell to convince elected representatives to advocate to skeptical voters.

Duane said PJM is one of the most transparent organizations he has been a part of, with a deluge of information published. He said the complexity of those postings should not be mistaken for a lack of transparency.

PJM Stakeholders Discuss Governance

The MC and board discussed the issues raised during the technical conference during the Sept. 25 meeting — a standing agenda item recently established by board Chair David Mills in response to the calls for more transparency and accessibility to board members.

John Horstmann, senior director of RTO affairs at AES Ohio, said he heard a lot of criticism and finger-pointing at PJM's leadership, but little in the way of solutions to the issues the states and RTO face together. He said there seems to be little interest in being involved in the stakeholder process to advance their causes.

"The real issue is load is growing faster than we can make supply … and they don't like it, but I didn't hear how they would fix it if you handed them the keys today," he said.

He said he did not see how creating a governors' organization is going to be any different from the deference PJM and its membership already provide to the Organization of PJM States Inc. (OPSI).

Manager Matt Nelson said the governors want to bring load growth to their states and see it interconnected at the least cost.

"There's a real goal of making sure we can show the value of PJM, and that isn't just PJM itself but this whole process. And when I hear governance, I hear them say they want a way to engage in this process," he said.

Sophia Dossin, manager of regulatory affairs for Middle River Power, said the growth of large load customers felt like a hot potato at the technical conference, and while PJM will have a role to play in how to manage that growth, it is limited by its jurisdiction.

"Everybody wants the benefits; nobody wants the cost," she said.

Dossin also said the membership should consider what Christie said at the conference: that individuals the PJM membership might call "consumers" are referred to as "voters" by elected officials. Communications between PJM and state leadership would be well served by approaching those conversations as speaking to voters, she said.

OPSI Executive Director Gregory Carmean said PJM should provide easily understandable information about rule changes being considered. Pointing to the slate of Quadrennial Review proposals voted on during the Sept. 25 meeting, he said a short description could have been provided on each, along with a statement on how it would benefit the public.

Asthana told the MC that his interpretation of what states are requesting from PJM is a measure of control over the RTO and lower prices, which he said the membership should keep in mind and consider how those goals can be addressed. That control is not PJM's to give, he said, and is instead under the purview of the membership, with management considering how to facilitate that conversation.

To address the need for a tenfold increase in the amount of capacity coming online, he said solutions spanning the state and federal jurisdictional boundary will be needed, creating an opportunity for PJM to partner with the states in a different way than it has in the past. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Widened Provisional Interconnection Service

PJM's Markets and Reliability Committee endorsed by acclamation a set of *manual revisions* to expand when a new resource could be granted provisional interconnection service to allow for early operation when it becomes capable of injecting a portion of its output while its network upgrades are still underway.

PJM Director of Interconnection Planning Donnie Bielak said the RTO brought the changes against a backdrop of an increasing number of emergency procedures with the objective of making as many resources as possible available to dispatchers in the coming years.

The Planning Committee endorsed the quick fix proposal Sept. 9, including an issue charge to explore creating a process for PJM to proactively identify resources which could take advantage of provisional service. (See *PJM Stakeholders Endorse Expansion of Provisional Interconnection Service*.)

Interim deliverability studies are conducted to determine if resources that have been completed, but are still awaiting completion of assigned network upgrades, can operate without triggering transmission violations.

Under current rules, if a unit cannot reliably inject its full output, it is denied provisional service. The proposal would create a second round of analysis to determine if a resource not capable of full operations could provide output at a fraction of its nameplate. If so, an operational guide would be produced to inform dispatchers how the unit could be operated. Project developers must request, and pay, for PJM to conduct the studies, which would not be changed by the proposal.

Bielak said PJM is processing studies for the 2026/27 delivery year and is planning to present the results in the next few weeks. If the change is approved, it will be applied to the results and no further action is needed from developers who have already sought provisional service for that year.

PJM board Chair David Mills | © RTO Insider

Stakeholders debated an amendment PJM proposed to add the phrase "consistent with PJM's governing documents" to language outlining the information the RTO would publish about individual requests for interim deliverability studies, including the location and provisional output desired. After a dialogue with stakeholders, PJM revised the amendment to instead state that applicants "agree to waive their rights to confidential treatment of such requests" and agree to the publishing of that information.

Proponents of requiring the disclosures argued transparency is needed around the requests to ensure applicants would not have insider information about the resources likely to be in operation months before other market participants become aware.

Independent Market Monitor Joe Bowring said the proposal is a great step forward on PJM's part but contended that the resource owner should be obligated to perform when dispatched by PJM. Without such a requirement, the RTO could not rely on any possible reliability benefit from provisional resources.

Committee Approves Changes to DR Participation in Regulation Market

Stakeholders endorsed a *proposal* to allow demand response resources to enroll to provide regulation-only service when there are energy injections at the point of interconnection. (See "PJM Reviews Proposal on Regulation Resources at NEM Sites," *PJM MRC/MC Briefs: Aug. 20, 2025*.)

The changes would allow a DR resource to participate in the regulation market when there is no load or a net injection at its POI with the consent of its relevant electric distribution company memorialized in a net energy metering agreement.

Intelligent Generation CEO Jay Marhoefer said the proposal would restore a mode of DR participation that was lost in previous FERC orders on the regulation market.

During the July 9 Market Implementation Committee meeting, he said some EDCs changed their tariffs in a manner that inadvertently prevented behind-the-meter

storage from participating in the regulation market while injecting. (See "Stakeholders Endorse Changes to Storage Participation in Regulation Market," *PJM MIC Briefs: July 9, 2025*.)

Bowring said advancing one element of PJM's Order 2222 compliance filing would provide special treatment for one class of market participants and open the door for others to ask for expedited treatment for their preferred components.

"Clearly the FERC thought it was reasonable to do this, but in 2029," he said.

Cost Allocation for DOE Emergency Orders

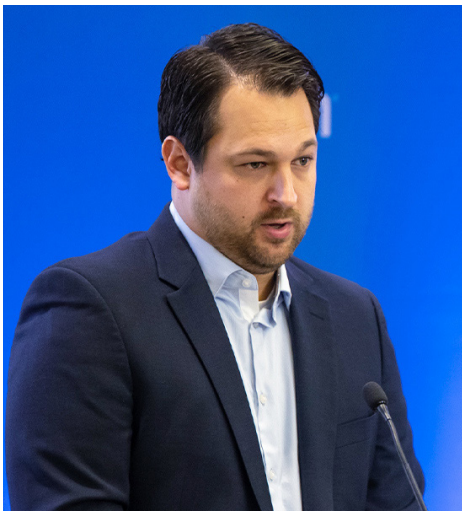
The MRC and Members Committee endorsed a *proposal* to define how PJM would determine how to allocate the costs associated with operating generators under a DOE emergency order. (See *PJM Stakeholders to Examine Rules for Future DOE Emergency Orders*.)

For orders addressing an RTO-wide resource adequacy issue, PJM would use a *pro forma* cost allocation that splits the costs a resource owner incurs under the emergency order across all RTO load based on each entity's share of the monthly unforced capacity obligation. The *pro forma* approach would be used only when resource owners and PJM agree to use the deactivation avoidable cost credit (DACC) compensation model.

If the RA concern affects specific regions, PJM would initiate an "abbreviated stakeholder consultation" with the goal of drafting Reliability Assurance Agreement (RAA) revisions addressing cost allocation. The process would pick up where the PJM DOE 202(c) Cost Allocation Senior Task Force left off on identifying recommended approaches for the RTO's Board of Managers to consider.

If there is an emergency order unrelated to RA, PJM would initiate a Critical Issue Fast Path (CIFP) process, similar to how it proceeded after the U.S. Department of Energy ordered Constellation Energy and PJM to keep the Eddystone Generation Station outside Philadelphia online past its scheduled deactivation at the end of May. (See *FERC Approves Cost Allocation for Eddystone Emergency Order*.)

The abbreviated stakeholder consultation would be considered a workshop under a new section to be added to Manual 34: PJM Stakeholder Process,



Donnie Bielak, PJM | © RTO Insider

with voting at the MC. The *pro forma* cost allocation would be added to the RAA under Section 7.2A Responsibility to Pay 202(c) Charge.

Denise Foster Cronin, EKPC's vice president of federal and RTO regulatory affairs, said she is glad PJM adopted a wider perspective on how it could proceed under different scenarios, but argued the proposal remains flawed without any way for PJM to determine the cause of an RA emergency order without direction from DOE. She said the department is unlikely to delve into the drivers of RA needs.

Sophia Dossin, of Middle River Power, said the RTO should think about how to proceed if there is disagreement between PJM and stakeholders about whether to move ahead with the pro forma.

Phil Sussler, of the Maryland Office of People's Counsel, argued stakeholders should have an opportunity to gain more insight into what costs can be recovered under the DACC methodology. He said units whose deactivations are being deferred are more likely to be older and run into unexpected problems that substantially increase costs. Consumer advocates protested PJM's cost allocation filing for Eddystone, arguing that the compensation should be subject to FERC oversight rather than a bilateral agreement between PJM and the resource owner.

Responding to a stakeholder question, PJM's Lisa Morelli said the costs to keep Eddystone online in June were covered by the revenues it received in PJM's markets.

Regulation Market Manual Revisions Approved

The committee endorsed by acclamation a *revision* to Manual 11: Energy & Ancillary Services Market Operations to reflect the adoption of a tracking metric for the amount of regulation a resource should be providing. The change was included in the first phase of PJM's redesign of the regulation market; however, language detailing the calculation of lost opportunity cost credits did not reflect the tracking regulation set point. PJM's Brian Chmielewski said the changes are to be rolled out at the beginning of October. (See "Update on Regulation Market Design," *PJM OC Briefs: April 3, 2025*.)

Members Committee

Stakeholders Endorse Revisions to CIR Transfer Filing

PJM's Members Committee endorsed a set of *revisions* to a proposal to rework how capacity interconnection rights (CIRs) can be transferred from a deactivating resource to a replacement following FERC's rejection of the original tariff changes (*ER25-1128*). (See *PJM Preparing Alterations to Rejected CIR Transfer Proposal*.)

The changes to the proposal center on two exemptions from the commercial operational date requirements for the replacement resource — one for resource types known for long development timelines and a one-time allowance for an indefinite COD delay. In its Aug. 8 denial, the commission found that allowing developers deferrals that could last years could open the door for owners to withhold CIRs by tying them up in theoretical planned resources.

The new COD requirement would mandate the replacement unit be in service by the greater of four years from the submission of the replacement generation application or three years from the deactivation date of the original resource. An amendment offered by Vistra added a requirement that the resource be online within three years of its planned in-service date and reserves the right for a developer to seek a FERC waiver from the COD requirements.

Vistra's Erik Heinle said the change provides room for PJM and developers to negotiate the milestones.

PJM's Jason Shoemaker said staff de-

signed the revisions around the Reliability Resource Initiative (RRI), a one-time window PJM opened to allow 51 resources to have their interconnection studies processed under Transition Cycle 2. Like the CIR transfer proposal, RRI was intended to allow resources likely able to come quickly into service to have their interconnection process expedited.

The larger proposal aims to speed the process for studying whether a replacement resource requires network upgrades and offer an interconnection agreement within nine months of a request to transfer CIRs. A resource would be permitted to pursue the expedited process even if minor network upgrades are identified, and a categorical prohibition on storage resources would be eliminated. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

Discussion with Board Members on Large Load Growth

The Board of Managers discussed with stakeholders an ongoing CIFP process addressing large load growth, continuing a standing item on the MC agenda that board Chair David Mills sought in an effort to improve the transparency and accessibility of the body.

Opening the conversation, Mills said much of the CIFP meetings thus far have focused on the RTO's non-capacity backed load (NCBL) and bring your own generation proposals, but many of the comments submitted at the onset of the process focused on the load forecast and the need to ensure understanding of the scale of the problem. He questioned how the membership prioritizes improving the load forecast relative to solutions focused on serving large loads.

Asthana said PJM has removed NCBL from its CIFP proposal based on opposition from much of the membership. *Materials* for the Oct. 1 CIFP meeting say PJM is shifting the focus to a price-responsive demand model similar to a voluntary NCBL model and a parallel expedited interconnection queue.

Heinle said the load forecast will dictate the range of solutions stakeholders should focus on, scaling to the size of the problem, and recommended that PJM integrate a "ground-up" perspective on the amount of data center load expected in the region. He said there seems to be an assumption that every data center load is coming to PJM, even while that industry sees many of the same supply chain issues plaguing the electric industry.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said this is one of the biggest discussion points stakeholders face, with load growth expected in the next five to seven years exceeding the total load served by CAISO. If those estimates are accurate, he said he's not aware of any changes PJM can make to bring on sufficient generation in time.

Exelon's Alex Stern said the load forecast is an important data point but is one of many the states and utilities use to guide their decisions around ensuring load is served. He said there has been a great deal of work done already at the Load Analysis Subcommittee to improve the transparency of the data presented there, as well as on the large load adjustment submission process. ■

— Devin Leith-Yessian

SPP Considers Deferring 765-kV NTCs to 2026

2025 ITP Portfolio's Hefty Costs Approach $19B

By Tom Kleckner

SPP says accelerating load projections will result in a 2025 transmission plan that dwarfs the previous year's record $7.65 billion portfolio — so much so that it is considering deferring some projects until 2026.

Staff said during a Sept. 23 education session on the *2025 Integrated Transmission Planning assessment* that they may recommend delaying construction permits for five 765-kV projects, totaling more than $5 billion in building costs, to the 2026 ITP.

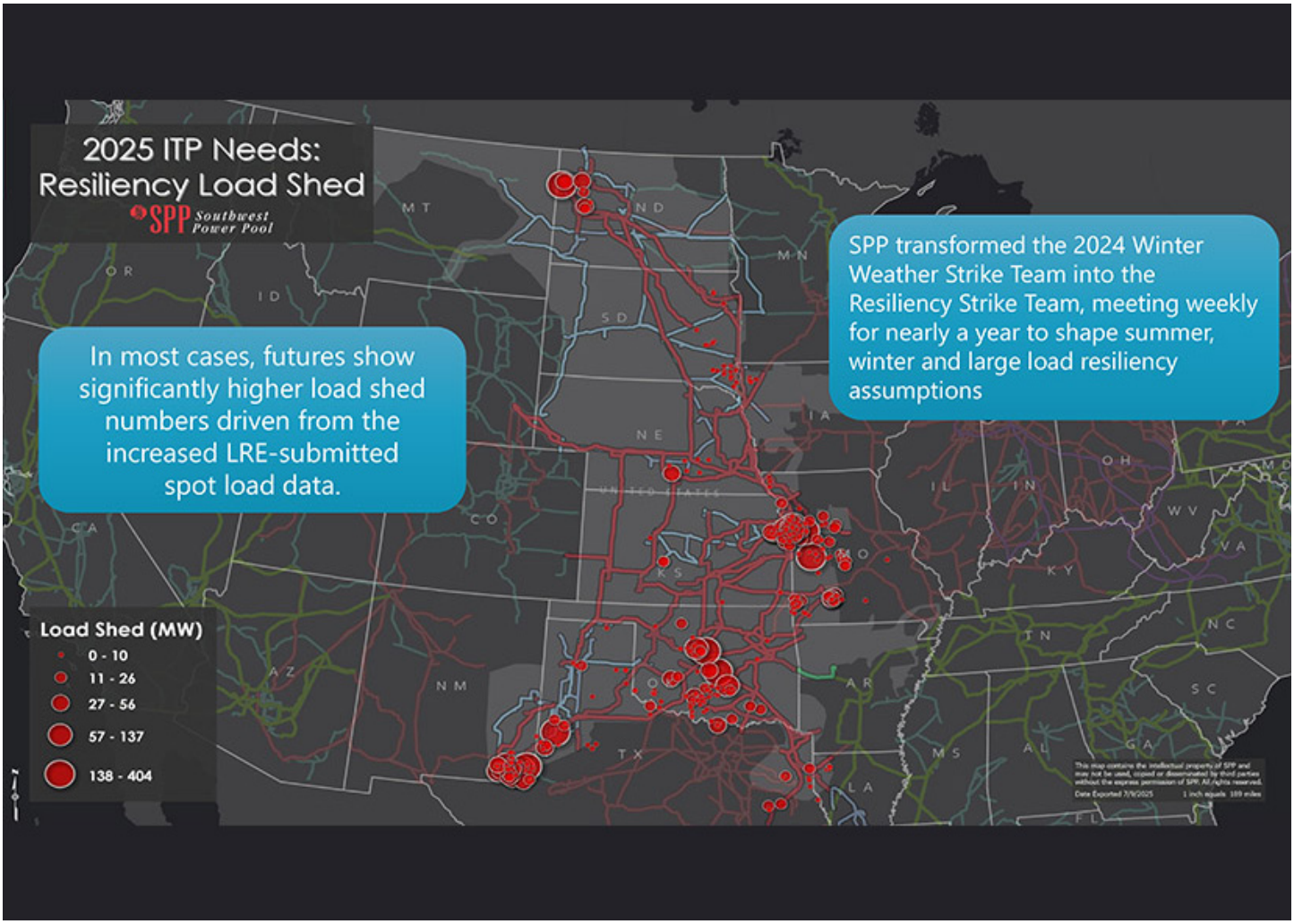
Having only received approval for its first 765-kV project in February 2025, Southwestern Public Service's 354-mile transmission line crossing the New Mexico-Texas border, SPP staff have experienced firsthand the vagaries of the facilities' high costs.

The project initially was projected to cost $1.69 billion. SPS revised the estimate to $3.62 billion in June. It took several months and more meetings and discussions with stakeholders before the Board of Directors eventually approved the revised cost estimate in September. (See *SPP Board Approves 765-kV Project's Increased Cost*.)

"We realize that these projects are very costly … we do expect to continue to show some additional cost sensitivities," transmission-planning manager Kirk Hall said during the Markets and Operations Policy Committee's education session. "We've talked a lot about the costs of the portfolio and obviously, affordability is top of mind. We've heard that loud and clear from stakeholders. We realize this is a significant investment."

"You can add as many projects as you want, and you are going to get some benefit, but at some point, that amount of reliability is not affordable to customers," Oklahoma Gas & Electric's Brad Cochran said, referring to the discussions over the SPS project. "You guys did a good job of putting some deferrals in there, but we need to make sure that not only [are we] making the system reliable, but we're making it affordable so that customers can actually pay their bills."

SPP said the draft portfolio costs $19.1 billion but provides about $80 billion in benefits, a benefit-cost ratio of between



Map shows where SPP expects load-shed events if it doesn't build transmission to meet needs in its resiliency model. | *SPP*

5.8 and 9.5. That doesn't include reliability benefits or the cost of outages.

Having identified the need for 765-kV transmission in the 2024 ITP, staff developed the EHV overlay and shared it with the board, state regulators and members in September. (See *SPP, Members Developing 765-kV Transmission Overlay Plan*.)

Hall said staff will vet their deferral recommendation with the Transmission and Economic Studies working groups before MOPC's October meeting.

SPP told the committee that the 2025 portfolio is the result "of our most comprehensive ITP process in history." Staff began with more than $20 billion in projects identified to meet all needs. It may end up with between $14 billion and $18 billion in projects that are issued notifications to construct, more than double the 2024 portfolio.

Casey Cathey, SPP's vice president of transmission, said the hefty portfolio is necessary. He recalled a time less than 10 years ago, when SPP was "excited" by 1.2% load growth year over year.

"We're seeing more than double that today, and we're seeing a lot higher, accelerated growth in the future," he said.

Cathey told MOPC that the 10-year firm load projections for 2033 that drove the record 2024 portfolio are expected to occur six years earlier in the latest forecasts. He pointed to voltage and transfer issues the grid operator faces, three load sheds in 2025, three winter peaks in the past five years and load-responsible entities forecasting new large loads that will require more transfer capacity: "We currently peak at 56 GW, and adding the amount of load that we have on the horizon … is, quite frankly, breaking the system. We will need to build transmission. Generation alone cannot solve our challenges."

The RTO expects future loads to increase. Staff referenced President Donald Trump's *executive order* to "pursue bold, large-scale industrial plans" that "vault" the U.S. "further into the lead" on critical manufacturing processes and the Department of Energy's *Speed to Power initiative*.

According to the DOE, data centers used 58 TWh in 2014. That number increased to 176 TWh in 2023, 4% of all U.S. electricity. By 2028, the agency expects data centers to need between 325 and 580 TWh, which would be 6 to 12% of the nation's annual energy.

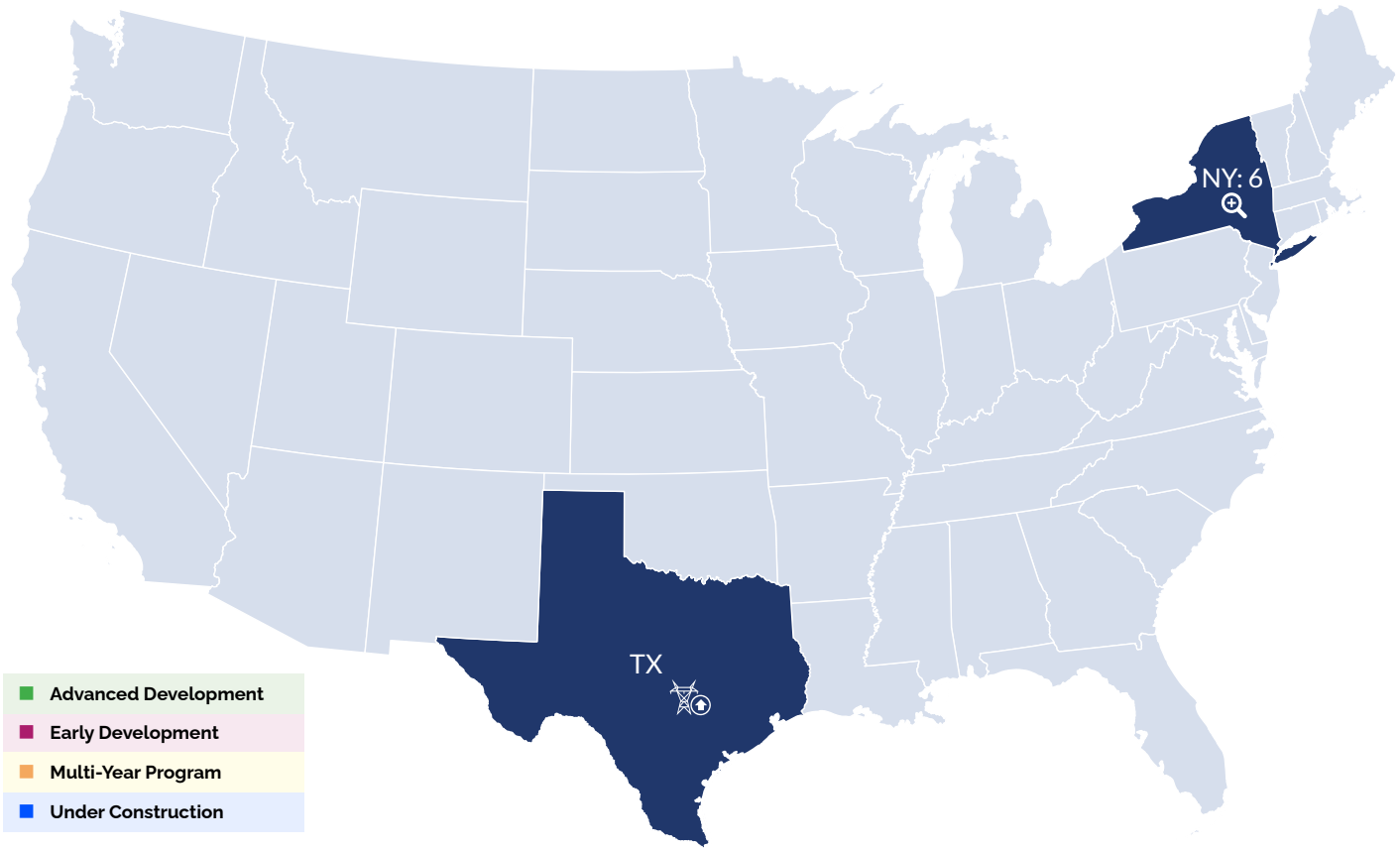
Data centers account for 23% of SPP's large loads in the ITP (2.5 GW of 11 GW), but oil and gas electrification in the Permian Basin and the Dakotas is responsible for double that. Combined, projected large loads are equivalent to 20% of the grid operator's current peak.

"There is heavy pressure to ensure that we're not only reassuring critical manufacturing but also doing what we can to provide bold infrastructure plans for large loads," Cathey said. "We're looking at this and seeing what opportunities we might have as we continue to plan the system out, not only for 765 kV but, just ultimately, the overall transmission infrastructure that we need."

The grid operator plans to release the ITP draft report Sept. 24. ■

T&D Projects Added in the Past Week

YES ENERGY



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
	Station 5 Upgrade	Avangrid	Rochester Gas and Electric	12	2027	NY
	Transmission Line L795 Upgrade	Avangrid	Rochester Gas and Electric	35	2029	NY
	Transmission Line L701 Upgrade	Avangrid	Rochester Gas and Electric	35	2027	NY
	RG&E Substation Major Program 2031 - 2035	Avangrid	Rochester Gas and Electric	35	2035	NY
	RG&E Distribution Line Inspection Repairs 2029 - 2033	Avangrid	Rochester Gas and Electric	35	2033	NY
	Station 192 Circuit Upgrades	Avangrid	Rochester Gas and Electric	12	2027	NY
	Buda - Rutherford Line Upgrade	Pedernales Electric Cooperative, Inc.	Pedernales Electric Cooperative	138	2028	TX / TX

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

Company Briefs

Amazon, Avangrid Announce Solar PPA

Amazon and Avangrid last week announced a solar power purchase agreement that will power more of the company's Oregon data centers.

Avangrid's Oregon Trail Solar project will generate 57 MW when it becomes operational in 2027. Amazon also signed a separate deal last year to buy power from Avangrid's 100-MW wind farm in Gilliam County.

More: *The Oregonian*

Blue Ridge Power Laying Off 517 Workers, Ending Business

Blue Ridge Power, an engineering, procurement and construction solar company created by Pine Gate Renewables, will lay off 517 workers in Asheville and Fayetteville as it ends its business, according to a notice filed with the North Carolina Department of Commerce.

The company will eliminate 348 positions in Fayetteville and 169 in Asheville by Nov. 18.

Pine Gate formed Blue Ridge Power in 2021.

More: *Business North Carolina*

Green Plains Completes Sale of Ethanol Plant

Green Plains last week announced it has completed the previously announced sale of its ethanol plant in Rives, Tenn., to POET Biorefining - Obion.

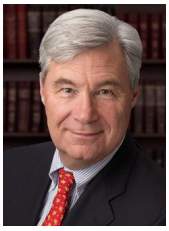
The sale was for $190 million in cash and includes $20 million in working capital.

More: *Green Plains*

Federal Briefs

Democratic Sens. Oppose EPA Plan; GOP AGs Dispute Climate Science

Every Democratic senator last week signed a letter in opposition to the Trump administration's proposal to axe a 2009 endangerment finding, an EPA determination that concluded the accumulation of six greenhouse gases posed a serious threat to public health.



The effort, led by Sen. **Sheldon Whitehouse** (D-R.I.) and Senate Minority Leader Chuck Schumer (N.Y.), comes after the administration said it would axe the finding in July. The administration allegedly used studies authored and published by scientists who deny the existence of climate change to justify the decision.

Conversely, GOP attorneys general from 26 states submitted a letter supporting the move. The letter also stated the EPA finding has underpinned "some of the worst policies of the last decades," citing the Clean Power Plan that aims to curb carbon emissions from existing power plants and federal electric vehicle "mandates."

More: *The Hill*; *Kentucky Lantern*

U.N. Climate Chief: New National Climate Plans will Fall Short

With governments announcing ambitious emissions reduction targets at a U.N. summit in New York last week, U.N. climate chief Simon Stiell warned they will not add up to what is needed to keep global warming to the limits in the Paris Agreement.

"We know [the national climate plans] are going to be softer than what science dictates," Stiell told the opening of Climate Week in New York.

Despite the expected emissions gap, growing criticism of the U.N. climate process and rising global temperatures, Stiell maintained the 2015 Paris Agreement is working to curb global warming. Projections before it was adopted suggesting a 5-degree Celsius rise are now down to around 3 degrees.

More: *Climate Home News*

DOE Adds 'Climate Change,' 'Emissions' to Banned Words List

The Energy Department last week added "climate change," "green" and "decarbonization" to its "list of words to avoid" at its Office of Energy Efficiency and Renewable Energy, according to an email.

Other terms officials must stay away from include "energy transition," "sustainability/sustainable," "'clean' or 'dirty' energy," "Carbon/CO2 'Footprint'" and "Tax breaks/tax credits/subsidies."

"Please ensure that every member of your team is aware that this is the latest list of words to avoid — and continue to be conscientious about avoiding any terminology that you know to be misaligned with the administration's perspectives and priorities," the directive from acting Director of External Affairs Rachel Overbey said.

More: *POLITICO*

National/Federal news from our other channels

Six Reports Paint Picture of Slowing Energy Transition

NetZero Insider

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

State Briefs

CALIFORNIA

CARB Repeals Private EV Truck Rule

The Air Resources Board last week voted to repeal its zero-emission purchasing rule for private fleets.

CARB released data showing manufacturers sold 30,026 zero-emission trucks in 2024, a 7% increase compared to 2023. The medium-duty sector accounted for nearly all those sales. The nation's four-largest truck manufacturers — Daimler Truck North America, International Motors, Paccar and Volvo North America — also sued the state last month to break a 2023 voluntary agreement to follow the ZEV rules.

More: *POLITICO*

COLORADO

Xcel Energy Settles Marshall Fire Lawsuit for $640M

Xcel Energy last week settled a lawsuit from victims of the 2021 Marshall fire ahead of trial, with Xcel paying $640 million without admitting any fault.

An investigation by the Boulder County Sheriff's Office concluded there were two sources for the fire. An old trash fire at a Twelve Tribes compound was reignited by high winds, and less than a quarter of a mile away an arcing Xcel Energy powerline set a second fire.

The Marshall fire was the state's most devastating wildfire, as the Dec. 30, 2021, blaze burned 6,000 acres, destroyed more than 1,000 homes and commercial buildings, and left two people dead.

More: *The Colorado Sun*

CONNECTICUT

DEEP Approves Energy Savings Plan

The Department of Energy and Environmental Protection has approved the state's 2025-2027 Conservation and Load Management Plan.

The three-year plan is a comprehensive strategy which guides the priorities, design and incentives for the state's energy efficiency and demand management programs. The programs are administered by Eversource and Avangrid.

More: *WTIC*

MAINE

Governor's Office Launches New Department of Energy Resources

Sept. 24 marked the official launch of the state's Department of Energy Resources.

The state joins more than 40 other states with a department specifically dedicated to energy planning and sourcing.

More: *Maine Public Radio*

State Celebrates Completion of Downeast Wind Project

Community leaders gathered last week to celebrate the completion of Downeast Wind, a clean energy project nearly a decade in the making.

The $300 million project, developed by Apex Clean Energy, features 30 turbines producing 126 MW.

More: *WFVX*

MINNESOTA

PUC Approves Solar-plus-storage Project

The Public Utilities Commission last week unanimously approved Primergy Solar's Northern Crescent Solar and Storage project.

The facility will produce up to 150 MW of solar capacity paired with 50 MW of battery storage.

The project is expected to be operational in 2028.

More: *MPR News*

NEW YORK

Judge Voids Law Curbing Radioactive Indian Point Discharges

U.S. District Judge Kenneth Karas last week ruled in favor of Holtec International, the company dismantling the Indian Point nuclear power plant, saying a state law designed to limit potential contamination of the Hudson River was preempted by federal law.

Karas said the state law could not stand because it significantly constrained Holtec International's decision-making in how to dispose of radioactive materials safely.

Holtec sued to block a 2023 law signed by Gov. Kathy Hochul that made it illegal to discharge radioactive materials into the Hudson in connection with the decommissioning. The company said its plan to dispose of millions of gallons of tritiated water complied with Nuclear Regulatory Commission licenses and regulations.

More: *Reuters*

RHODE ISLAND

Energy Efficiency Council Votes Against RI Energy's Proposed Cuts

The Energy Efficiency Council last week voted not to endorse Rhode Island Energy's 2026 plan, which included cuts to energy efficiency programs.

Rhode Island Energy reps said the company suggested its energy efficiency cuts after hearing concerns from customers and that the cuts would affect programs not being used fully by customers. However, dozens of lawmakers, including House Speaker Joe Shekarchi, were vocal against the plan.

The council is expected to meet again in October.

More: *WPRI*

VIRGINIA

Dominion's Chesterfield Gas Plant Case Begins at SCC

A case before the Corporation Commission involving Dominion Energy's proposed Chesterfield Energy Reliability Center began last week.

The SCC will need to decide if the 1-GW gas plant, which would only run about 37% of the time, is needed and reasonable for ratepayers to cover. The facility is the first of six proposed gas plants Dominion says are needed to meet growing demand.

A decision is expected in the coming months.

More: *Virginia Mercury*