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CAISO/WEST

Pathways Bill Passes Calif. Legislature in Lopsided Votes

Office of Assemblymember Cottie Petrie-Norris

While the new bill still gives California an out from participating in the RO, its contents largely align with the principles and plans set out by the Pathways Initiative.

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FERC/FEDERAL

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Swett and LaCerte Nominations Clear Committee on Party Line Votes (p.6)

The two nominees need to get approved by the entire Senate in floor votes before they can move into offices at 888 First Street NE.

MISO

Enbridge Gas Distribution and Storage

MISO Discloses $280M Error, Over-procurement in 2025/26 Capacity Auction (p.29)

A software error discovered in the complex calculations for MISO's loss-of-load expectation likely means that the RTO has secured more capacity than necessary in auctions dating back to the 2018/19 planning year.

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Georgia Power

The Long-Awaited Nuclear Renaissance Shows Signs of Promise, But Still has a Long Way to Go (p.3)

To succeed, new nuclear plants will need to be cost-competitive, says Peter Kelly-Detwiler. Manufacturers will have to build the manufacturing facilities to make all the parts and entice enough firm orders to create the necessary economies of scale.

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In this week's issue

The Long-awaited Nuclear Renaissance Shows Signs of Promise, But Still Has a Long Way to Go

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

Amid the growing push for new sources of power generation — especially from the data center sector — we have seen an extraordinary number of announcements concerning nuclear power. At this point, they are occurring almost weekly, something few would have anticipated just a few years ago.

These announcements generally fall into one of three areas: rehabilitation of closed nuclear facilities, potential development of new large-scale facilities such as the AP 1000 technologies currently deployed across the country, and development and deployment of an entirely new class of smaller reactors commonly referred to as small modular reactors (SMRs) or modular nuclear reactors (MNRs). The buzz in the space is considerable, but there still are numerous hurdles to be overcome before we can declare a win for the much anticipated "nuclear renaissance."

Plant Vogtle Units 3 and 4 | *Georgia Power*

Not Dead Yet

In recent years, numerous nuclear plants were struggling to survive, especially in competitive power markets where low-cost gas-fired and renewable plants were seriously denting their economics. Indeed, the economic outlook was so poor that five states (Connecticut, Illinois, New York, New Jersey and Ohio) *threw their nuclear plants lifelines* and created subsidy programs to keep 14 nuclear plants operating.

Several other states, though, chose to let plants be taken out of service. The typical decommissioning process is to remove and store the fuel, dismantle the plants and decontaminate the sites. In fact, *that process* has been followed by dozens of sites over recent decades.

However, as forecast power demand has rapidly increased recently, several recently decommissioned sites are now being pressed back into service. These include the *837-MW Three Mile Island 1* in Pennsylvania that is slated to deliver power to Microsoft for 20 years, the 800-MW Palisades plant in Michigan and the *615-MW Duane Arnold facility* in Iowa. And most recently, Holtec International, the owner of the 2,000-MW decommissioned Indian Point nuclear plant in New York, *suggested the possibility* of rehabilitating the facility for an estimated $10 billion.

While these efforts eventually may bring back over 4,000 MW of capacity online, there may not be many other resurrection efforts to follow, since many of the other decommissioned plants are either too far along in the process or may not prove economically viable.

An addition to this category might include the uncompleted *V.C. Summer plant* in South Carolina, which was abandoned in 2017 after burning through $9 billion of investment capital. That facility was thought to be dead until January 2025, when utility Santee Cooper issued a request for proposals seeking "to acquire and complete, or propose alternatives, for two partially constructed generating units at the VC Summer Nuclear Station." In May, the utility said it had received responses to the RFP but offered few details.

Revisiting Large Light Water Reactors

New nuclear power supply may come from the traditional light water reactors that have been employed by the U.S. power industry for many decades. For example, the proposed gargantuan 11,000-MW Fermi Project in Texas recently *submitted an application* to the NRC that includes four, 1,000-MW Westinghouse AP1000 nuclear reactors. (The last such units deployed were in the Vogtle plant in Georgia back in 2023, coming in more than seven years behind schedule and $17 billion over the original budget.) However, it appears that the new smaller and modular nuclear technologies may dominate this space.

Smaller Cookie-cutter Modular Units

In recent years, SMR-related investments and project announcements have surged, with much of this coming from the data industry. Dozens of companies — from large and established energy players such as GE, Hitachi, Rolls Royce and Westinghouse to numerous startups — are vying for success in this industry. They typically distinguish themselves from the existing light water reactor technologies in terms of size and technology, with many boasting fail-safe designs.

Models range in size from so-called "micro reactors" as small as 1 MW to larger units offering almost 500 MW of output. Many startups feature competing technologies that have not yet been tested commercially, and given the large number of contenders, many will fail commercially. But that hasn't seemed to slow the sector of late. In fact, in the frothy SMR waters, just since mid-August the following commitments have been heralded:

- Tennessee Valley Authority *announced a contract* with developer ENTRA1 Energy for a 6,000-MW deployment of MNR startup NuScale's 77-MW reactors, the only ones thus far to have received NRC approval for their design.
- Startup *X-energy hailed a collaboration* with Amazon, Korea Hydro & Nuclear Power and Doosan Enerbility "to accelerate the deployment of new Xe-100 advanced nuclear reactors in the United States," with a stated goal of deploying more than 5,000 MW of new nuclear capacity across the U.S. by 2039, while mobilizing up to $50 billion in public and private investments.
- Data co-location giant *Equinix announced* three separate deals with different modular nuclear companies for nearly 775 MW of new capacity in the U.S. and Europe, with power to come from reactors ranging in size from just over 1 MW to 470 MW.
- Finally, the Utah Office of Energy Development (OED), TerraPower (the Bill-Gates-backed company) and Flagship Companies *signed* a memorandum of understanding "to explore the potential siting of a Natrium reactor and energy storage plant in Utah."

It's increasingly looking like a new generation of nuclear reactors may become part of our energy future.

Big Data, Big Commitments

Much of the recent momentum is directly attributable to the data center companies that are hungry for power, while in many cases striving to maintain commitments to reduce associated carbon emissions. In addition to Equinix's more recent announcements, it also had *signed a deal* to buy up to 500 MW of power from SMR startup Oklo, with a $25 million pre-payment for future power output and a right of first refusal for from 100 to 500 MW of power.

Google also has been active. In May, *it signed an agreement* with nuclear project developer Elementi to commit early-stage development capital to support at least three projects that each would generate more than 600 MW. The company has the option to be a project off-taker once the facilities are commissioned (terms and locations were not specified).

In October 2024, *Google said* it would financially support deployment of seven SMRs from startup Kairos Power that eventually would generate up to 500 MW of output, with a first unit operational by 2030 and additional reactors online within five years. Kairos already *has started* construction of a demonstration project in Oak Ridge, Tenn.

For its part, *Amazon has invested* more than $500 million in SMRs, and took the anchor role in a $500 million *funding round* supporting SMR developer X-energy. And last fall, *Oracle announced* it intended to develop data centers powered by SMRs.

More such announcements are likely to come as the data center industry appetite for new power supplies continues to grow. Data centers are not the only industries showing interest. Among others, *utility Energy Northwest* and materials science company *Dow* both have committed to projects using X-energy's technology, with Dow already having designated a development site in Texas.

Rare Bipartisan Support in Washington

While the promotion of many energy sources fall into red or blue camps, nuclear generally has managed to remain purple. In 2024, *Congress passed* the strongly bipartisan Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy (ADVANCE) Act, which specifically seeks to promote advanced reactor technologies.

In addition, the U.S. Department of Energy has provided significant financial support, including a *$900 million effort* that began during the Biden administration to accelerate the development and deployment of SMRs. In August, *DOE selected* 11 advanced reactor projects for accelerated deployment, streamlined testing and fast-tracking toward commercialization.

A Nuclear Renaissance Won't Happen Unless Certain Conditions are Met

Major challenges remain to be addressed before we can proclaim the nuclear industry as reborn. The thorny nuclear waste issue remains to be solved. So does the issue of security. It's one thing to guard the *50+ nuclear sites operating today* and quite another to secure hundreds of them. There also are the siting challenges and the problem of convincing neighbors to accept these plants in their communities. Nuclear sites also will face the same interconnection challenges that have bedeviled any other generating assets connecting to the grid.

Perhaps most critically, though, these new nuclear plants will need to be cost-competitive. Manufacturers will have to build the manufacturing facilities to make all the parts and entice enough firm orders to create the necessary economies of scale. It will not be enough for companies to build these new nuclear reactors in the single digits. The winners in this race likely will need to build dozens of them *to get the costs down* to where they can become competitive with other sources of generation.

It's one thing to do that with solar modules or batteries, where global supply chains wring out inefficiencies through production of literarily hundreds of millions of the devices. It's quite another to create such efficiencies in a new industry, in which there are many competing companies and technologies.

To succeed, the infant industry will have to migrate from one-off projects to a broad-based, factory-centered production approach, enjoying a large and predictable order book. It also will need to nurture the necessary talent to manufacture, site and operate the plants in the field. We're not remotely there yet, but for fans of a nuclear renaissance, recent events offer encouraging signs. ■

Around the Corner columnist Peter Kelly-Detwiler of NorthBridge Energy Partners is an industry expert in the complex interaction between power markets and evolving technologies on both sides of the meter.

What Does a Reliable Grid Cost?

By Michelle Bloodworth


Michelle Bloodworth

More and more, energy policy analysis seems to be based on finding a preferred answer rather than a realistic answer. Case in point, a recent Grid Strategies *report*, sponsored by several environmental organizations, claims that Department of Energy emergency orders to temporarily keep fossil power plants from retiring could cost either $3 billion or $6 billion annually by 2028.

Each estimate is based on a different assumption about how many fossil fuel power plants might retire over the next three years. For perspective, these costs, even if correct, would represent either 0.6 or 1.2% of annual consumer expenditures for electricity, which total about $500 billion. (*According to EIA*, end use electricity expenditures totaled $488 billion in 2023, which is the most recent data.)

The Secretary of Energy has the legal authority under Section 202(c) of the Federal Power Act to issue orders to prevent "energy emergencies." The potential reliability problems NERC has been warning about qualify as an emergency under the Federal Power Act.

Former FERC Chair Mark Christie *in July warned* that "the reliability threat is not on the future horizon. It is now here."

One of the primary reasons for these serious warnings is the retirement of fossil power plants. That's why it has become increasingly important to stop retiring power plants because they are needed for reliability.

From a cost-benefit standpoint, it's important to consider the benefits of 202(c) orders, which the report ignores. DOE, for example, *estimates* the annual cost of blackouts to be $150 billion.

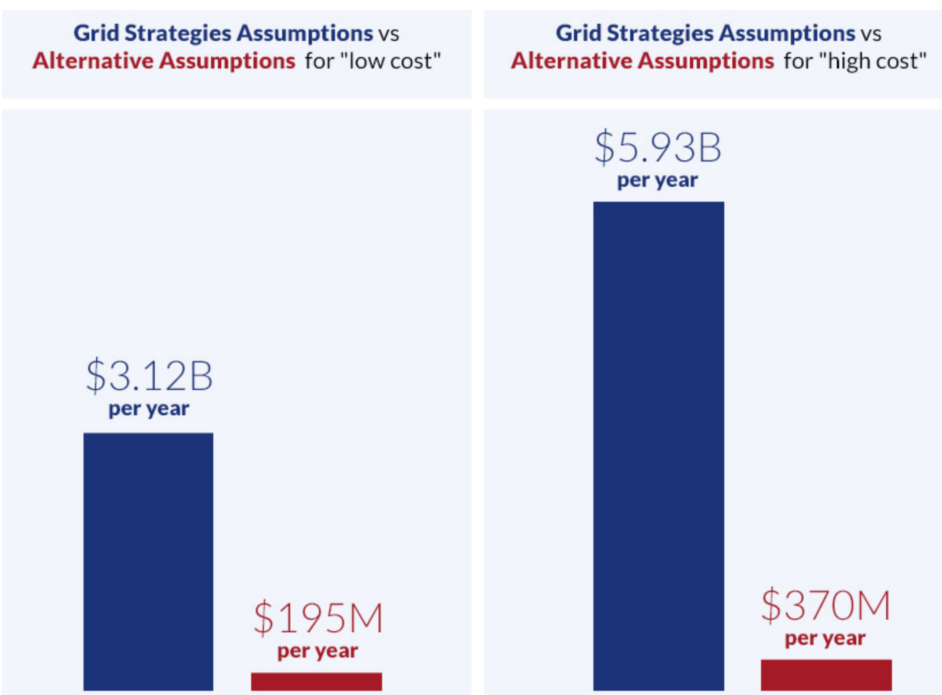
Also, an unreliable electricity grid during Winter Storm Uri *cost* the Texas economy between $80 billion and $130 billion.

As to the possible cost of DOE orders to keep plants running, the report makes a number of questionable assumptions that drive its large cost estimates. One assumption is that all fossil power plants (as many as 90, according to the report) that might retire for one reason or another over the next three years actually will retire.

This seems improbable because fossil power plants will be needed to satisfy load growth driven by data centers, advanced manufacturing, crypto mining and electrification of the economy, and EPA is rewriting rules that were expected to cause the premature retirement of many fossil power plants. In fact, utilities already are changing their minds and, so far, have deferred the retirement of *29,000 MW* of coal-fired generation.

Why This Matters

Suspending plans to retire coal and natural gas power plants is even more critical for grid reliability than issuing temporary 202(c) orders, says Michelle Bloodworth.



| Michelle Bloodworth

Another assumption is that every one of these 90 retiring plants would be directed by DOE to continue operating for a full year. However, we don't really know how many plants actually would receive 202(c) orders, but we know that DOE's authority under Section 202(c) has been used sparingly — *just 27 times since 2000*. Only two of these orders lasted for more than 90 days, so assuming that every retiring plant, regardless of how many there might be, would be directed to operate for one year seems unlikely, if not improbable.

We thought using different assumptions would be an interesting way to test the Grid Strategies cost estimates. So we assumed that fewer retirements would happen (half the number Grid Strategies assumed), that only half of these retirements would receive 202(c) orders and that the orders would direct each of the plants to operate for three months, not a full year.

With these alternative assumptions, the cost estimates are more than an order of magnitude lower. The $3 billion estimate is reduced to a little less than $200 million, and $9 billion is reduced to $370 million.

Obviously, no one knows what will happen by 2028, but suspending plans to retire coal and natural gas power plants is even more critical for grid reliability than issuing temporary 202(c) orders. ■

Michelle Bloodworth is president and CEO of America's Power.

Swett and LaCerte Nominations Clear Committee on Party Line Votes

By James Downing

The two nominees to open seats on FERC, Laura Swett and David LaCerte, both cleared the Senate Energy and Natural Resources Committee in largely party line votes of 12-8 in a hearing Sept. 11.

Swett is widely considered to be named the chair of FERC assuming her nomination gets through a full Senate vote. With LaCerte, the two commissioners would give President Donald Trump a majority on FERC for the first time this term. The committee votes came just a week after Swett and LaCerte testified in another hearing. (See: *Senators Focus on FERC's Independence at Swett, LaCerte Confirmation Hearing*.)

Committee Chair Mike Lee (R-Utah) said FERC has important authority that ensures a reliable and affordable energy system and that the two nominees would help get that work done.

"It performs these and many other functions that in many cases not all of us think about every day. When it performs that duty with discipline within FERC, the country prospers. When it strays from its mission, the bill lands squarely on the kitchen tables of American families. That is the gravity of the task before Ms. Swett and Mr. LaCerte. Both nominees bring with them valuable experience that can serve the commission."

David LaCerte | © *RTO Insider LLC*

Swett has been a FERC attorney at the law firm Vinson & Elkins and has worked at the commission before, including as staff for former Chair Kevin McIntyre and former Commissioner Bernard McNamee. LaCerte lacks direct experience with FERC.

Laura Swett | © *RTO Insider*

Why This Matters

The two nominees need to get approved by the entire Senate in floor votes before they can move into offices at 888 First Street NE.

While Lee said LaCerte is qualified for the job, Ranking Member Martin Heinrich (D-N.M.) noted that FERC nominees are, by statute, supposed to be experienced on the issues before the regulator.

"The commission's independence, its bipartisanship and its members' expertise have always been part of its strength," Heinrich said. "They have contributed to, rather than detracting from, the making of good energy policy, and I believe Ms. Swett has the necessary qualifications for this job."

Normally, Heinrich said, he would have voted in favor of Swett's nomination. He added that LaCerte lacked the qualifications for the job, saying he "does not meet the basic statutory requirements." However, neither of them got his vote and all but one Democrat on the committee voted against the pair.

"These are not normal times," Heinrich said. "This administration is issuing illegal stop-work orders on fully permitted projects. They are creating a grid crisis. They are killing good union jobs, and they are raising electricity prices, and until they are willing to comply with the letter of the law, it will be difficult for me to support their nominations."

The two nominees need to get approved by the entire Senate in floor votes before they can move into offices at 888 First St. NE. Sen. Lisa Murkowski (R-Alaska) asked Lee to impress on leadership the imperative of getting FERC back to a full quorum. ■

Permitting Hearing Shows Tricky Politics of Getting a Bill Passed

By James Downing

Why This Matters

Republicans and Democrats support permitting legislation this year, but partisan rancor around other issues could stop it from happening.

The House Natural Resources Committee held a hearing Sept. 10 on three pieces of permitting reform legislation that showed the political disputes that will have to be solved if any of them are going to pass.

"It's a bipartisan issue," Chair Bruce Westerman (R-Ark.) said in opening remarks. "It's not just people who vote Republican that are coming in my office to tell me that. We had a hearing on this topic in July, and in that hearing, many of my friends across the aisle were calling fouls on the current administration, saying they shouldn't be doing this. But you know what? This time a year ago on our side of the aisle, we were calling fouls on the Biden administration, saying they shouldn't be doing this."

Congress has an opportunity to enact permitting legislation that will improve the process regardless of who occupies the White House, he added.

The committee is not the only one working on the issue, with the House Energy and Commerce Committee planning a *hearing* on other permitting legislation for Sept. 16. Senate committees have been crafting bills as well. (See related story, *Permitting Legislation Effort Picks Up Steam, but Passage Remains Difficult*.)

Two of the bills before the committee, *H.R. 573* and *H.R. 4503*, are focused on modernizing the permitting with new technologies and enhanced data, but Ranking Member Jared Huffman (D-Calif.) said Westerman's bill — the SPEED Act (*H.R. 4776*) — "takes a sledgehammer" to the National Environmental Policy Act's core provisions.

"The SPEED Act treats public input like it is an annoyance, like a hurdle, rather than a resource that can guide better decisions," Huffman said. "It restricts what major environmental impacts can even be considered for review. It eliminates the spotlight that NEPA provides for the public to help government get it right, and by shrinking analysis and compressing timelines without investing in greater agency permitting capacity, you're really just inviting shoddy analysis, and ultimately that's going to lead to more litigation and uncertainty."

The act is meant to cut red tape and relieve the "logjam" caused by onerous reviews under NEPA that have slowed down infrastructure projects, Westerman said.

"NEPA must be further reformed to put definitive guardrails around what agencies are expected to review," he added. "Much like the review documents themselves, the NEPA litigation has gotten out of control. NEPA is the most frequently litigated environmental statute."

The SPEED Act does have a Democrat as a co-sponsor: Rep. Jared Golden (Maine), whose district is among the most conservative in New England, with President Donald Trump winning it in the past three presidential elections. But beyond the opposition from the leading Democrat on the committee, other members of the rank and file questioned why they should work with an administration that is actively working against their states' policies.

"I want to get to 'yes' on this bill," Rep. Seth Magaziner (D-R.I.) said. "I'm not there now, but I want to get there because I understand that … we need to build out our infrastructure, repair our highways and bridges, and achieve the clean energy transition and so much more. We need to make it easier to build in this country again."

The conversation about how to balance against the need for environmental protections and allowing impacted communities a voice in the NEPA process is something that normally Congress should be engaged in, he added.

"But we are having this normal conversation in an abnormal time, a time when the Trump administration is unilaterally and most likely illegally canceling and stopping clean energy projects, including a very important project in my district, the Revolution Wind project that was set to deliver energy to the grid at a below-market rate for consumers and meet a third of my state's electricity demand," Magaziner said.

The bills before the committee have their merits and deficiencies, but they also have to be considered in the context of the administration blocking clean energy, he added. ■

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EPA Moves to End Greenhouse Gas Reporting Program

8,000-plus Emitters would save $303M Annually in Compliance Costs, EPA Estimates

By John Cropley

EPA is moving to end greenhouse gas emissions reporting requirements for electricity generators and dozens of other industrial sources.

Administrator Lee Zeldin *announced the proposal* Sept. 12, saying the reporting is not mandated under the Clean Air Act, has no bearing on the environment or public health, and imposes hundreds of millions of dollars a year in compliance costs on American businesses.

Eliminating the requirement will help streamline operations, unleash American energy and advance EPA's core mission of protecting human health and the environment, he said.

More than 8,000 facilities and suppliers in 47 source categories are subject to the requirements of the Greenhouse Gas Reporting Program.

The move was not unexpected. Zeldin *announced March 12* that EPA was reconsidering the program.

It is the latest of many attempts to roll back regulations and protections, and it fits with the Trump administration's skepticism regarding global climate change.

"It costs American businesses and manufacturing billions of dollars, driving up the cost of living, jeopardizing our nation's prosperity and hurting American communities," Zeldin said Sept. 12. "With this proposal, we show once again that fulfilling EPA's statutory obligations and Powering the Great American Comeback is not a binary choice."

Environmental advocates expressed dismay and vowed to fight.

The *Sierra Club* countered that the program was in fact fully authorized under the Clean Air Act and said: "EPA cannot avoid the climate crisis by simply burying its head in the sand as it baselessly cuts off its main source of greenhouse gas emissions data."

Why This Matters

The move would limit the accounting of emissions blamed for global warming.

The Walter Scott Jr. Energy Center in Council Bluffs, Iowa, produced 5.7 million tons of carbon dioxide emissions in 2023, according to the EPA, which is proposing to lift greenhouse gas reporting requirements for power generation and many other sources. | *© RTO Insider*

The *Environmental Defense Fund* said it would fight the move because "the information shows the sources and scale of pollution that causes climate change, including from oil and gas facilities, landfills, and power plants, allowing for better decisions about how to address that pollution. The Greenhouse Gas Reporting Program allows us to create policies that make life safer, healthier and more affordable for all Americans."

The *proposed amendments* to the Greenhouse Gas Reporting Program run 114 pages. EPA will accept comments for 47 days after it is published in the *Federal Register*.

EPA indicated in a *fact sheet* that it is proposing to permanently remove reporting requirements for 46 source categories because there is no statutory requirement for it to collect that data except for petroleum and natural gas emitters in Subpart W subject to the Waste Emissions Charge.

(Subpart W is being undercut as well: EPA proposes to halt reporting for one of the 10 industry segments and suspend reporting for the other nine until 2034, as directed by the One Big Beautiful Bill Act.)

EPA estimates the proposal will save businesses $303 million a year through 2033. That breaks down to $256 million for Subpart W sources and $47 million for the other 46 sources. ■

EIA Increases Projections of Power Generation Growth

Expected Load Growth in PJM, ERCOT Alters 2026 Outlook

By John Cropley

The U.S. Energy Information Administration is boosting its estimate of national power generation growth to 2.3% this year and 3% next year.

The details are reported in the *September Short Term Energy Outlook* the agency issued Sept. 9. In the outlook published in January, it had forecast an average of 1.5% growth in 2025 and 2026.

EIA said the increase is from a colder-than-expected start to 2025 and load growth assessments by ERCOT and PJM. The latter had the largest amount of generation of any region in 2024: 873 billion kWh. It is expected to have 904 billion in 2025 and 946 billion in 2026.

ERCOT is forecast to have to the largest increase in generation, from 459 billion kWh in 2024 to 560 billion in 2026 — a 22% jump.

The *January STEO* forecasted only 499 billion kWh in ERCOT in 2026 and only 902 billion kWh for PJM.

The predictions for all other grid regions are nearly the same in the September report as in the January report.

To meet this rising demand, utility-scale solar generation is expected to increase 33% this year over 2024, the most of any technology, and then 19% in 2026.

Natural gas generation is expected to be 3% lower in 2025 than in 2024 because of sharply higher gas prices, but it still will be the largest source of electricity by a wide margin, providing 1,698 billion kWh, or 40% of the country's electricity.

Coal-fired generation is expected to be 9% higher this year than last — the first year-over-year increase for coal since 2021. The 2024-2025 decrease in gas and increase in coal both are approximately 61 billion kWh.

Small increases also are forecast in 2025 for wind power (4%) and hydropower (2%). Together with solar, this puts renewable energy at 25% of U.S. electricity generation in 2025 and 26% in 2026, compared with 23% in 2024.

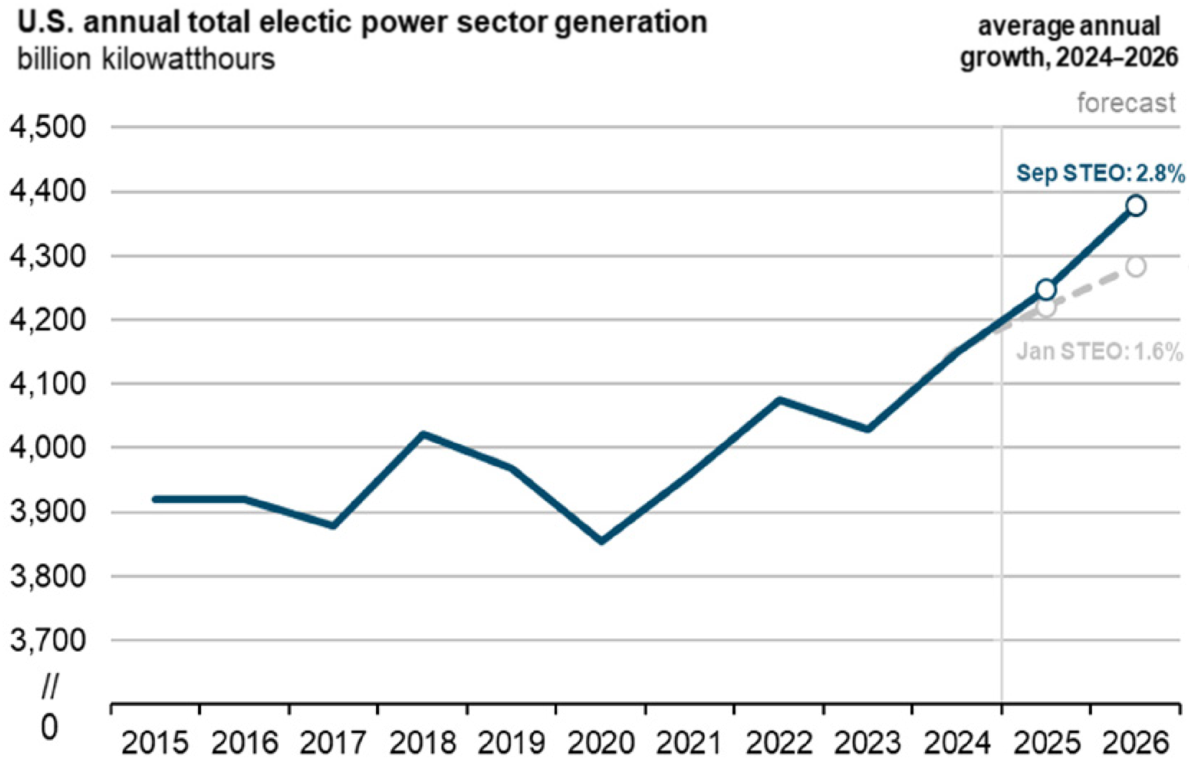
Nuclear fission is expected to produce only slightly more power in 2025 than in 2024 but 2% more in 2026, thanks to the anticipated restart of the Palisades Nuclear Plant in Michigan.

The average price per kilowatt-hour is projected to increase from 16.48 cents in 2024 to 17.22 cents in 2025 and 17.9 cents in 2026 for residential customers; 12.85 to 13.36 and 13.5 cents for commercial customers; and 8.15 to 8.49 to 8.54 cents for industrial customers.

Nationwide average electricity prices for the three classes are projected to be 13.53 cents/kWh this year and 13.79 cents next year. The West South Central region — Texas, Oklahoma, Arkansas and Louisiana — retains the lowest average in 2025, at 9.87 cents/kWh, and New England remains highest, at 25.12 cents. ■

Why This Matters

The projections reflect rising power demand expected in parts of the country.



The U.S. Energy Information Administration in January estimated annual electric power generation would average 1.6% in 2025 and 2026. In September, it has increased the forecasted average to 2.8%. | *EIA*

EPRI, NEI Update Roadmap for Advanced Nuclear Buildout

Blueprint Identifies Priorities, Challenges and Solutions

By John Cropley

The Electric Policy Research Institute and Nuclear Energy Institute have issued an update to the *Advanced Reactor Roadmap* they launched in 2023.

The update comes after a period of steady progress by the nuclear power industry as well as rapidly increasing interest in and support for it.

In their *Sept. 9 announcement*, EPRI and NEI said the blueprint could help enable buildout of more than 300 GW of advanced nuclear generation capacity in North America. It identifies completed actions, new priorities and evolving industry needs over the past two years.

"When it comes to new nuclear power, the challenge isn't demand but being able to build fast enough to meet it," NEI Executive Director of New Nuclear Marc Nichol said in a news release. "The North American nuclear industry is confident in the ability to rise to the challenge and deliver the reliable, affordable and clean energy needed to power the future."

The updated roadmap breaks the challenge down into three key issues — regulatory efficiency, technology readiness and project execution — and seven enabling factors to deliver value on a timely schedule: first-mover success, fast followers, regulatory efficiency, siting availability/permitting, indigenous/public engagement, supply chain ramp-up and workforce development.

In July 2023, Vogtle Unit 3 became the first advanced nuclear reactor to enter commercial operation in the United States. Construction is shown in progress in May 2020. | *Georgia Power*

The update is significantly longer and more detailed than the initial version, and it, too, will evolve with future developments and further stakeholder input.

The 2025 update notes that after the initial roadmap was issued in May 2023:

- Vogtle Units 3 and 4, the first new U.S. advanced reactors, began commercial operation.
- A host of state and federal policy and regulatory actions have boosted support for nuclear generation.
- The sector has seen extensive private investment and agreements for offtake from facilities still in the research and planning phases.
- The first small modular reactor in North America was approved for construction in Ontario.
- More than 60 other new nuclear projects are being planned in the U.S. and Canada; several have secured regulatory approval; and a handful have begun construction.

Steve Chengelis, EPRI vice president of energy supply, said: "Using the roadmap as a guide, the nuclear industry has made significant strides in areas such as piloting accelerated material qualification projects, advancing workforce training and recruitment, and assessing how construction methods can reduce the risks of new builds."

The roadmap spells out in detail the expected benefits of widespread deployment of advanced nuclear generation.

It also flags 49 issues posing potential hurdles to advanced nuclear technologies, including:

- Risk must be reduced and mitigated to give investors and customers the necessary confidence to be first movers.
- Some of the fuels that advanced reactors are being designed around have yet to be demonstrated commercially, and significant public and private investment is needed to get those fuels to market.
- Other parts of the supply chain are inadequate, and investment in specialized production to create a supply chain is contingent on certainty of demand.
- The construction skillsets the nuclear industry will need are in short supply and in high demand.
- There is a collective lack of institutional knowledge, because so little nuclear construction has occurred in the U.S. in the past 30 years; because much will change from past practice; and because most prospective owner/operators will be new to the field and may lack necessary skills or experience.

Why This Matters

The roadmap lays out the promise of advanced nuclear reactors, progress toward that promise and ways to overcome challenges facing that promise.

But the roadmap also spells out the steps that need to be taken to address these challenges and identifies the key stakeholders who are or will be addressing the various issues.

The Tennessee Valley Authority has been among the early movers in U.S. planning and development of advanced nuclear technology, and it spoke of the value the roadmap has offered over the past two years.

"The roadmap's collaborative approach has helped unify diverse stakeholders around a common vision for advanced reactor deployment," Scott Hunnewell, vice president of TVA's New Nuclear Program, said in the news release. "As a national leader in advancement of new nuclear technologies, we're proud to contribute to this effort and look forward to continued progress." ■

DC Circuit Upholds FERC PURPA Decision Without Chevron Deference

By James Downing

A three-judge panel of the D.C. Circuit Court of Appeals on Sept. 9 *upheld* its decision to side with FERC over whether a solar plant in Montana is a qualifying facility under the Public Utility Regulatory Policies Act without relying on *Chevron* deference.

The Supreme Court had remanded the initial decision in July 2024, after it had ended the *Chevron* doctrine in *Loper Bright Enterprises v. Raimondo*. (See *PURPA Case Offers FERC Early Glimpse of Post-Chevron World*.) Under the doctrine, courts would defer to regulatory agencies in their administration of a law as long as their decision-making was reasonably explained.

In *Solar Energy Industries Association v. FERC*, the D.C. Circuit still sided with the commission that the Broadview facility, with 160 MW of nameplate capacity, is a QF. The solar plant includes a 50-MWdc battery, limiting the power that actually flows to the grid to PURPA's 80-MW maximum, FERC found.

FERC has consistently defined power production capacity as the amount of power a facility can ship to the grid, but the petitioners in the case, including NorthWestern Energy, argued that it should be applied to the nameplate capacity.

Initially, the court sided with FERC under the *Chevron* precedent, but in the decision issued Sept. 9, it concluded under *Loper Bright* that power production capacity should be defined as the amount of power that can be sent to the grid.

"That reading accounts for all the facility's components working together, not just the maximum capacity of one subcomponent, and it appropriately focuses on grid-usable AC power," the court said. "Because the Broadview inverters' maximum output capacity at any given time is 80 MW of AC power, the entire facility's send-out capacity is capped at that level consistent with FERC's decision to certify it as a small power production facility."

Why This Matters

The case is an early example of how FERC and the courts will work without *Chevron* deference to regulatory agencies.

EMC Engineering Services

The generator is linking to the grid through NorthWestern's transmission system. The utility filed an objection to its certification at FERC along with the Edison Electric Institute. In a September 2020 order, FERC initially denied the certification, finding that the relevant capacity was the 160 MW of solar.

Broadview sought rehearing, and in March 2021 (soon after President Joe Biden took office), FERC reversed course and granted it QF status under PURPA.

FERC rejected arguments from EEI that the setup was designed to "game" PURPA's power production capacity limit. The facility's design enables a higher capacity factor, achieving its maximum 80-MW output about 35 to 40% of the time, with FERC finding that a permissible use of technology to boost its capacity factor while remaining under PURPA's limit.

After the D.C. Circuit sided with FERC in 2023, EEI and NorthWestern sought Supreme Court review. The high court granted the petition without deciding the merits, vacating the earlier decision based on the *Loper Bright* decision. On remand, the circuit court followed the Supreme Court's directive to exercise its independent judgment in deciding whether the agency had acted within its statutory authority.

"We hold that a small power production facility's 'power production capacity' refers to its maximum net output of AC power to the electrical grid at any given point in time," the court said. "Because the amount of power the Broadview facility can send out to the grid is limited by its inverters to 80 MW, it qualifies as a small power production facility under PURPA."

Based on the law's text, "facility" applies to all components as they function together, which includes the inverters and their 80-MW limit. The power production capacity rule refers to a "facility" rather than a particular subcomponent, such as a generator.

"The only grid-usable form of electric energy the facility produces is AC power," the court said. "The most natural reading of 'power production capacity' of the facility, then, is the amount of AC power that the overall facility transmits to the electrical grid." ■

Report: Gas Powerful Tool for Energy Assurance

By Holden Mann

With electric utilities worldwide facing rapidly rising demand and an "unpredictable" planning environment, natural gas continues to hold a strong role "supporting long-term sustainability and energy security" in the global market, according to the International Gas Union's 2025 *Global Gas Report*.

The report, released Sept. 10 and co-authored with European gas pipeline operator Snam, analyzed trends in the international gas market and compared them to developments in the electric landscape. Overall gas demand grew to 4,122 billion cubic meters in 2024, up 1.9% from the year before, while gas production grew by 65 Bcm, or 1.6%.

Demand growth was strongest in Asia, which consumed 36 Bcm (3.6%) more in 2024 than in 2023, followed by Russia, up 11.5 Bcm (2.5%), and North America, up 22.9 Bcm (2%). Consumption fell by 0.6% in South America and 1.5% in Africa. About 80% of the natural gas supplied in North America went to the U.S., IGU said, partly because of historically low Henry Hub prices making gas more cost-competitive with coal for electric utilities.

Power generation made up about one-third of gas consumption worldwide in 2024, more than any other application; industrial applications and residential and commercial uses came in second and third, continuing the pattern of the previous four years. Similar results were seen in North America, Asia and the Middle East.

Despite this steady demand growth, the report noted that "shifts in technology, climate and geopolitics" have introduced uncertainty into the market. Record high summer temperatures in 2024 contributed to peak power demands in multiple countries including the U.S. Import tariffs imposed by the Trump administration also have the potential to "weaken global liquified natural gas demand despite strong support for the oil and gas sector domestically … exacerbated by the unpredictable pace of the energy transition."

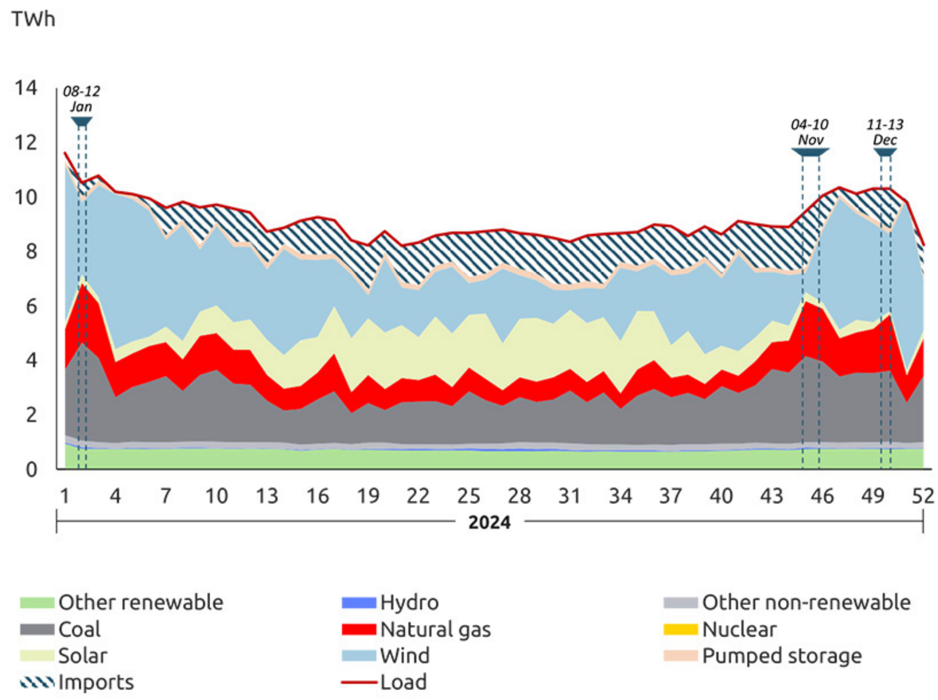
The ongoing data center boom is expected to drive structural increases in electricity demand as well. IGU observed that about 73 GW of new data center capacity is under construction and planned in the next five years, on top of the close to 45 GW that existed in 2024, with most facilities concentrated in Georgia, Arizona, Texas and Virginia. "Favorable conditions such as low-cost energy, tax incentives and robust fiber infrastructure" are behind the anticipated growth, according to the report.

In light of these growing pressures, IGU argued that "gas is well positioned as a force of resilience [and] a lower-carbon alternative to coal." The organization noted the use of gas as "insurance for power systems" that have seen growing penetration by intermittent resources like wind and solar, citing the "dunkelflaute" incidents in Germany in 2024 when wind activity, and thus wind power generation, fell off steeply, leaving the slack to be taken up by gas, coal and imports.

Gas also constitutes "a proven technology partner to batteries," the report said, pointing to the experience of California in the first six months of 2025, when gas regularly ramped up to compensate for decreased output from solar and battery facilities. These global examples show the role of gas "as a flexible solution in balancing [renewable energy] variability," IGU said.

Given the importance of gas, the report argued for the U.S. and other developed nations to pursue "targeted investment across the natural gas value chain, careful alignment of technology choices with system needs and reform of power market structures to ensure project viability." Potential value chain investments include upstream supply, midstream infrastructure such as pipelines and storage, and increased gas generation capacity. Market reforms could include clarifying the role of gas plants as support for renewable energy rather than as baseload power.

"The future role of natural gas in power systems will vary widely depending on feasibility considerations, best practices and regional integration strategies," the report said. "Existing infrastructure, current power mixes and policy environments will determine how extensively gas-to-power can contribute to system flexibility. Therefore, unlocking the full potential of natural gas as a dispatchable and balancing power source will require a set of targeted measures at both national and global levels." ■



The weekly power balance in Germany for 2024 by energy source, showing the use of natural gas to meet demand during periods of low wind generation. | *European Network of Transmission System Operators for Electricity*

Pathways Bill Passes Calif. Legislature in Lopsided Votes

Passage Marks Key Victory in Decade-long Effort to Transform CAISO into Western Market

By Robert Mullin

California lawmakers have passed a landmark bill that will allow CAISO to transition the governance of its markets to the independent "regional organization" envisioned by the West-Wide Governance Pathways Initiative.

With little discussion and no debate, Assembly Bill 825 on Sept. 13 passed the state Senate on a 34-0 vote, followed by a 67-2 approval in the Assembly. Days before the vote, backers of the recently revised bill had expressed confidence the measure would fly through both houses after the initial Pathways bill stalled in the Assembly in July.

AB 825 will implement the Pathways Initiative's "Step 2" plan to create a regional organization (RO) to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market — and authorize the ISO and California's investor-owned utilities to participate in the RO. (See *Pathways Initiative Approves 'Step 2' Plan, Wins $1M in Federal Funding*.)

"Some doubted if we'd ever get here, but we landed in a great place," bill co-sponsor Sen. Josh Becker (D) told his colleagues ahead of the Senate floor vote.

Referring to the previous three failed efforts — over 2016 to 2018 — to pass legislation to "regionalize" CAISO into a Western RTO, Becker said AB 825 "enables something that's been a decade in the making: a Western energy market."

"This is a pivotal moment for California, and we have an opportunity to make energy in the state of California cheaper, cleaner and more reliable," co-sponsor Assemblymember Cottie Petrie-Norris (D) said before the Assembly vote.

Becker and Petrie-Norris both played up the affordability angle of the bill, pointing to a January Brattle Group study showing California ratepayers stand to save about $790 million a year if the state were to participate in an "expanded EDAM" that consists of most of the West. The study showed those savings will be more modest, though still significant, in a more likely scenario in which the EDAM shares the region with SPP's competing Markets+ offering. (See *Brattle Study Shows Big Benefits for California in 'Expanded' EDAM*.)

Assemblymember Cottie Petrie-Norris took up sponsorship of the Pathways bill late in the 2025 session. | *Office of Assemblymember Cottie Petrie-Norris*

Why This Matters

While the new bill still gives California an out from participating in the RO, its contents largely align with the principles and plans set out by the Pathways Initiative.

Previous efforts to regionalize CAISO failed in large part due to the opposition of powerful labor interests — namely the International Brotherhood of Electric Workers — concerned about the impact of such a change on the buildout of renewable resources in the state. But this time around, labor, along with California's publicly owned utilities, became key supporters of the Pathways Initiative, along with clean energy and environmental groups, who see a broader Western market as a way for all participants to tap increased amounts of renewable energy through geographical diversity.

AB 825 also had bipartisan support in California's overwhelmingly Democratic state legislature.

"I think most of the stuff we're doing today will make life less affordable to Californians, but this is one bill that will make life more affordable for Californians," Republican Sen. Tony Strickland said before the Senate vote. "Expanding our energy markets to include other Western states will help us lower our costs for energy, and that is good for the people of California."

Petrie-Norris pointed to the estimated $7 billion California utilities have saved from their participation in the WEIM over the past 10 years.

"And this expanded, day-ahead market has even more potential for optimizing costs," she said. "The reliability benefits of this proposal are just common sense. As we move toward more weatherdependent renewables powering our grid, we need to ensure that we have a grid that is bigger than the weather. So with this proposal, the wider market will make it easier for California to rely on excess solar from Arizona or wind from Wyoming."

Renewed Support

Passage of the bill in its current form was the product of considerable last-minute maneuvering in the legislature, partly orchestrated — or enforced — by Gov. Gavin Newsom (D), according to sources close to the process.

The original vehicle for the "Pathways" legislation during the 2025 session was *Senate Bill 540*, sponsored by Democratic Sens. Josh Becker and Henry Stern. SB 540 passed the Senate in early July on a 39-0 vote after picking up a set of controversial amendments.

Those additions prompted some of the original bill's strongest backers to pull their support, causing the bill to stall in the Assembly. They particularly objected to a provision that would have authorized a new Regional Energy Market Oversight Council to force CAISO and the state's IOUs to withdraw from the regional market if it found participation no longer served the interests of the state. (See *Calif. Pathways Bill Delayed After Orgs Withdraw Support, While Newsom Signals Backing for Effort*.)

But just as the session was drawing to a close, the Pathways effort was given new life in the 11th hour after lawmakers from both houses worked behind the scenes to strip out the controversial provisions added to SB 540, then shifted the contents into AB 825, originally an "energy affordability" bill that already had passed the Assembly and was poised for a Senate vote before the legislature was scheduled to go into recess on Sept. 12. (See *Calif. Pathways Legislation Poised for Passage After Being Shifted into New Bill*.)

While the new bill still gives California an out from participating in the RO, its contents largely align with the principles and plans set out by the Pathways Initiative. With that, the backers who'd pulled their support renewed their calls for passage of the bill.

Some of those supporters were first out the door to celebrate passage of AB 825.

"Today's vote sends a message to the West. California will be part of a fast-moving revolution in how electricity will be bought and sold across the region," Katelyn Roedner Sutter, California state director at the Environmental Defense Fund, said in a statement. "Despite delays, California lawmakers have committed to regional action that will help deliver a clean, affordable energy future."

Sen. Josh Becker shepherded the Pathways bill through the California legislature during the 2025 session. | *Office of Sen. Josh Becker*

"This is a pivotal moment for the West, demonstrating California's commitment to regional collaboration and ensuring all states' voices will be represented," Leah Rubin Shen, managing director at Advanced Energy United, said. "The broad geographic footprint enabled by this legislation will provide the greatest economic benefits, improve affordability for consumers and support a more resilient future for the whole region."

The Northwest Energy Coalition (NWEC) said passage of the bill "has addressed the primary concern cited by the Bonneville Power Administration (BPA) when it chose Markets+" over EDAM in May: the CAISO market's lack of independent governance. (See *BPA Chooses Markets+ over EDAM*.)

"This legislation is a fundamental change to the governance of EDAM and makes BPA's choice to prioritize joining Markets+ over reducing energy costs for the region even more questionable," NWEC's Ben Otto said in press release. "We continue to urge BPA to reassess its decision, particularly in light of this fundamental change to the market options. BPA can still change course and choose the better energy market for Northwest customers."

Seattle City Light, a BPA preference customer that has strongly urged the agency to join EDAM rather than Markets+, said it "applauds the passage of AB 825 (formerly SB 540) as an important step toward establishing an independent, West-wide regional market."

This legislation reflects strong leadership and thoughtful engagement with stakeholders across the West, laying the foundation for a robust independent governance structure that will ensure reliable, affordable and clean energy outcomes for customers," the utility said. "Building on the success of CAISO's market services, AB 825 creates the opportunity for market participants across the west to collaborate and deliver the best results for the communities and customers we serve."

BPA called the passage of AB 825 "a positive development toward a more equitable market landscape in the West" but defended its decision to join Markets+.

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

"Markets+ offers the independent management and governance that Bonneville seeks and meets the needs of our customers. It also offers advantages in market design such as support for a regional resource adequacy platform and meeting the state policy obligations of its participants," it said.

CAISO commended the legislature, Gov. Newsom "and the diverse coalition of stakeholders for their leadership in advancing this important legislation. This marks a crucial next step toward independent governance of Western electricity markets — a milestone shaped by years of successful and evolving regional collaboration."

The ISO said it will "coordinate closely" with the Pathways Initiative as it develops the new RO "to ensure alignment with legislative requirements."

'Sound Foundation'

The passage of AB 825 unsurprisingly drew praise from those who drove the work of the Pathways Initiative.

"The [Pathways] Launch Committee is excited to see the California Legislature's passage of AB 825, enabling participation in the new, independent regional organization," Launch Committee co-chairs Kathleen Staks (Western Freedom) and Pam Sporborg (Portland General Electric) said in a statement. "It is a critical step in implementing the work of the Pathways Step 2 proposal and achieving the largest energy market footprint possible resulting in the greatest affordability and reliability benefits for customers. We are looking forward to the incorporation of the new, fully independent regional organization in the next few months and seating the initial board."

"Energy affordability and reliability are top of mind for households across the West", Oregon Public Utility Commission Chair Letha Tawney said. "The West-Wide Pathways Initiative and AB 825 have created a sound foundation for our work on these critical priorities. I appreciate the thoughtful work of the Launch Committee creating solutions that protect customers in every state."

"The dedication of the Launch Committee, and those involved from the beginning, deserve a huge round of applause!" Arizona Corporation Commission Chair Kevin Thompson said. "Thank you to the California Legislature for resolving the governance issue of developing a Western day-ahead market with the passage of, and signing of, AB 825. Well done!"

"Commissioners across the West are working to ensure as many options as possible exist to enable affordable, reliable power. The West-Wide Pathways Initiative is an example of what we are doing, [and] passage of AB 825 is an important element of achieving the goal," New Mexico Public Regulation Commissioner Pat O'Connell said.

"The passage of AB 825 is a significant step to improve electric reliability and affordability in the West," California Public Utilities Commission President Alice Reynolds said. "This achievement was the result of the extraordinary efforts the Pathways Launch Committee and a broad array of stakeholders across the West. I am grateful for everyone's contributions."

All four utility commissioners were signatories to the letter that launched the Pathways Initiative in July 2023. (See *Regulators Propose New Independent Western RTO*.)

The bill now goes to Newsom's desk. ■

WEIM Prices Rise on Higher Gas Costs in Q2 2025

Gas Resource Management Proposal Could be Ready in October

By David Krause

Western Energy Imbalance Market prices increased sharply in the second quarter of 2025 compared with the same period in 2024, mostly due to higher natural gas prices at Western hubs — with some seeing 80% gains.

That was a key finding in a report CAISO's Department of Market Monitoring (DMM) delivered at the Western Energy Markets Governing Body's general session Sept. 9.

The *report* showed 15-minute market prices across the WEIM averaged $26/MWh during the quarter, a 12% increase compared with 2024.

California experienced the highest electricity price in the market — about $28.40/MWh, marking a 22% increase. The Desert Southwest region saw the biggest gain at 40%, while Pacific Northwest prices were up 14%.

Rising gas costs and higher load drove the price gains, Eric Hildebrandt, DMM executive director, said in the report.

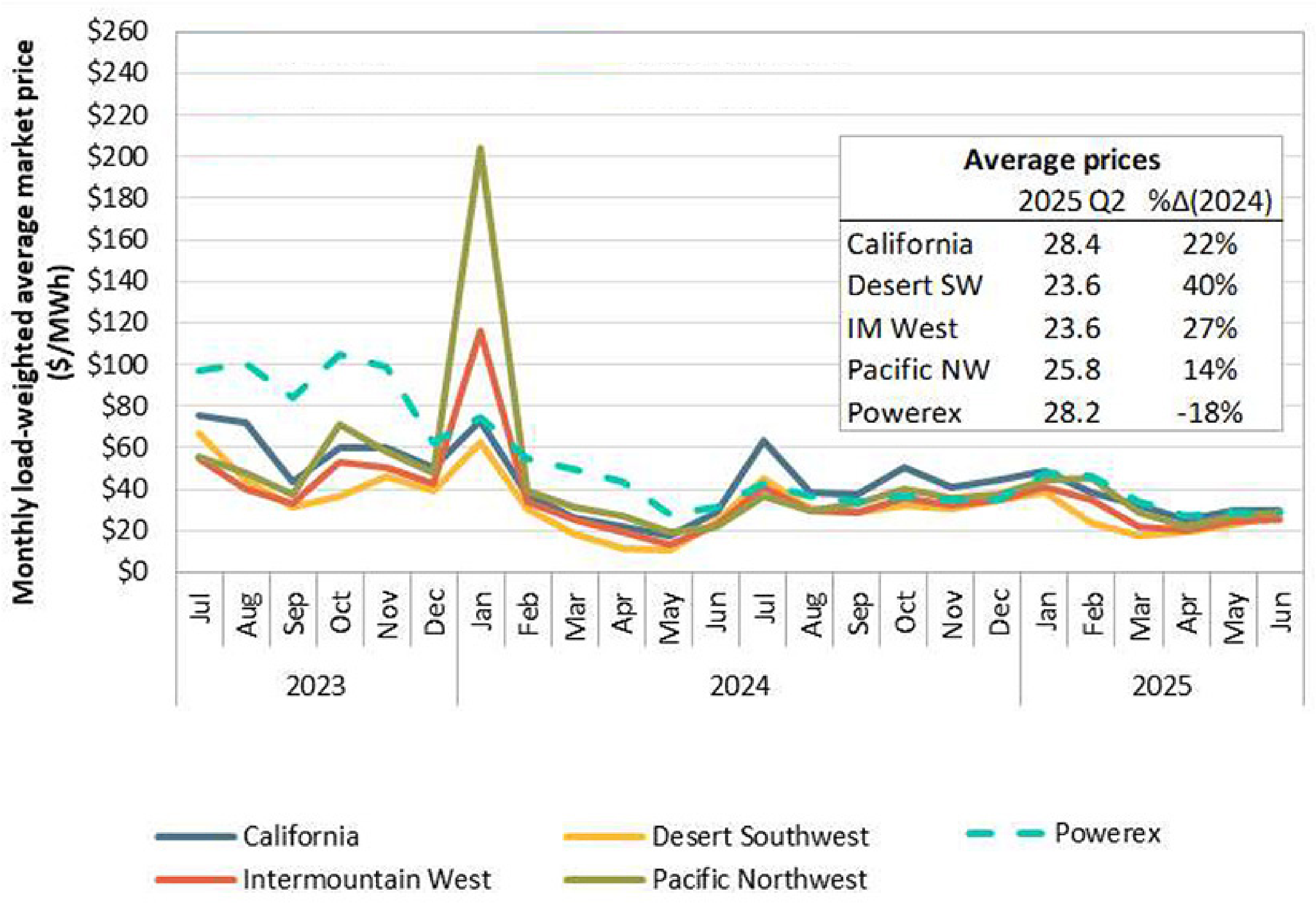
Natural gas prices at most major Western hubs were "up significantly compared to the second quarter of 2024," with the average prices at Henry Hub, PG&E Citygate, SoCal Citygate and NW Opal Wyoming increasing by 55%, 27%, 80% and 64%, respectively, compared with the second quarter of 2024, Hildebrandt said in the report.

Why This Matters

Despite California's efforts to move away from gas-fired generation, power prices in CAISO — and the WEIM at large — are still largely driven by the cost of natural gas.

Asked by *RTO Insider* to provide more insight into the causes of gas price increases, CAISO said it "doesn't monitor these markets directly."

"Our regulator, FERC, would be in a better position to answer this question," the ISO



Weighted average monthly 15-minute market prices by region over two years | *CAISO* said. "We generally treat gas prices as inputs."

Demand increased in the WEIM, too, but not by much: Total system load averaged 74.7 GW, which was about 1.4% greater than the load in the second quarter of 2024. The Pacific Northwest region's average load came in at about 21 GW, up 1% from the second quarter of 2024. CAISO's average load was about 22 GW, up 1.9%.

Policy Project Updates

Speaking during the session, WEM Governing Body Chair Rebecca Wagner said the WEM's policy projects are "back on track" after a "hiatus due to the work on the congestion revenue rights [initiative]."

Wagner said the WEM Governing Body was changing its approach to policy updates at its meetings.

"Rather than having a detailed policy initiative update, you can find that information in our informational reports … and so what we're going to do instead is just policy hot topics," Wagner said. "What are the key topical items that are rising to the top for ISO management and most importantly with stakeholders?"

Becky Robinson, CAISO director of market policy development, said the ISO is planning to potentially bring certain policy initiative decisions to the next WEM board meeting in October.

Specifically, Robinson said CAISO could have a proposal ready for a decision associated with the ISO's gas resource management initiative. That initiative has "set out to determine what parts of our market design may limit the ability of gas resources from participating in the WEIM or the EDAM when it's up and running next year," Robinson said.

The goal of the new proposal is to address what factors might be restricting gas resources' ability to accurately reflect their gas cost and availability, she said.

The proposal could include three parts.

First, it could provide updates to day-ahead advisory market runs, so that "we are providing that information to market participants … potentially in advance of the day-ahead market," Robinson said.

The second part could include providing additional options for cost inputs and cost recovery for gas resources to better accommodate variables such as extreme weather, she said.

The third part of the proposal could include additional options for managing certain limits currently encountered by gas resources, Robinson said.

No Joint General Session

The WEM Governing Body general session was held a day before the body's joint executive session with the ISO Board of Governors, but no joint public meeting between the boards will be convened in September — just as in July.

Asked about the reason, a CAISO spokesperson said: "General session meetings are held only when there are planned topics of discussion. Since there are no general session topics for the joint meeting or the Board of Governors meeting this month, those two general sessions were not scheduled." ■

NWPCC Updates Power Plan Model in Light of Trump

Model Update Comes amid Shifting Federal Policies

By Henrik Nilsson

The Northwest Power and Conservation Council has provided more details regarding how its ninth power plan will consider new federal policies that could affect the buildout of new resources and transmission.

The council will consider two priority scenarios to build the plan's model, including a changing hydro operations scenario and a new resource and transmission risk scenario, the latter of which was discussed during a Sept. 9 meeting.

"This is exploring a range of uncertainty or risk … related to the region's ability to build new resources and transmission," Jennifer Light, director of power planning at NWPCC, said during the meeting.

The resource and transmission risk scenario includes six sensitivities:

- constrained new resources.
- changing transmission availability.
- changing technology costs.
- limited short-duration storage availability.
- slower demand-side resource availability.
- evolving federal policy landscape.

These sensitivities are intended to help the council get a better understanding of the availability of resources under certain circumstances.

When council staff first started developing the sensitivities at the beginning of 2025, President Donald Trump had yet to target tax incentives for renewables under the Inflation Reduction Act. (See *NWPCC Considers Trump, Data Centers in Regional Power Plan*.)

Council staff anticipate the administration will remove amendments to the Clean Air Act that imposed stricter requirements on the buildout of new natural gas resources.

Five of the sensitivities originally were modeled with the tax credits and gas requirements in mind, and the evolving federal landscape scenario considered what would happen if those were removed.

The NWPCC is required under the Northwest Power Act to develop a power plan for the region. | *© RTO Insider*

Why This Matters

The NWPCC has to alter elements of the modeling behind its ninth power plan to reflect dramatic changes in energy policy under the Trump administration — including the rollback of Inflation Reduction Act investments.

"Well, now we're flipping that around a bit," Light said.

Since those clean energy incentives and gas requirements no longer are relevant, council staff have removed them from the bulk of their modeling. Instead, those are tacked on to the federal landscape scenario, which assumes the credits will return in 2030, Light explained.

"Why are we proposing doing that? Well, the IRA gives us a set of assumptions we can use," Light said. "We've already started using them. So, it wouldn't make sense to come up with different tax credits now, and I think that'd just be a lot of work and a lot of guessing, not necessarily getting us any more precise than using IRA assumptions that they come back."

The council is required under the Northwest Power Act "to develop a plan to ensure an adequate, efficient, economical and reliable power supply for the region," according to its website. NWPCC publishes a plan every five years, and the goal is to have a draft ninth power plan done by July 2026 and a final version by the end of that year. (See *NWPCC's Initial Demand Forecast Sees Sharp Growth for Northwest*.)

"If there is another administration down the road that wants to bring stuff in, it's not necessarily going to look identical to the Inflation Reduction Act," Light said. "But it is a set of policies that we have that we can use as a basis for assumptions that feels just as good as making a guess. And I think it will give us directionally useful information." ■

Utilities Back Some BPA Transmission Updates, Hesitate on Others

Agency Continues to Host Workshops on Its Transmission Planning Pause

By Henrik Nilsson

Utility representatives at a customer-led workshop voiced support for Bonneville Power Administration's shift toward "proactive" transmission planning, though some expressed reservations about the agency's proposed commercial readiness criteria.

The Sept. 10 *workshop was part of a series of public meetings* the agency is hosting as part of its Grid Access Transformation Project (GAT). The agency has paused certain transmission planning processes to consider changes in how it will tackle 65 GW of transmission service requests.

In July, BPA outlined its proposed plan to address the queue. The agency has developed a two-part approach: a transitional phase to get off the pause and a longer-term "future state" that will include more substantial reforms to BPA's existing transmission processes. (See *BPA Outlines Proposed Transmission Planning Reforms*.)

BPA's proposed future state, which includes shifting toward proactive transmission planning (an approach that seeks to forecast transmission needs and prepare the system ahead of time rather than just reacting to customer requests), received support from Seattle City Light (SCL) during the Sept. 10 workshop.

"We want to get to a future state where Bonneville is going through a planning process that's proactive and not reactive, so that planning process can look ahead 10, 15, 20 years using probabilistic analysis and come to some great outcomes for us as customers," said Michael Watkins, policy adviser at SCL.

Watkins also discussed BPA Administrator John Hairston's goal of reducing the time from transmission request to service to five to six years. (See *Industry Sees Challenges as BPA Considers 'Radical' Updates to Tx Planning*.)

"If we can get to that point, think about that world for our customers, where our customers can get interim nonfirm service in a short amount of time, whether

Spillway at BPA's Bonneville Dam. | *U.S. Fish and Wildlife Service*

that's to make a deal for a new resource, take advantage of a regional importer or exporter deal," Watkins said. "And then, within five or six years, firm that up, so that our customers can make long-term investments and count on using that transmission to serve load or to reduce their cost for a long period of time."

"We support that vision of the future, and while there's lots of details to work out on how we get there, we think that difficult discussion and working those details out is worth it," Watkins added.

BPA is also moving from a business practice process to a tariff proceeding process, or a Section 212 proceeding under the Federal Power Act.

Chris Jones, director of transmission policy and power delivery at Northwest Requirements Utilities, said he agrees "strongly with the encouragement to continue moving toward the proactive planning element."

"To me, that's the kind of crown jewel, the pot of gold at the end of this rainbow," Jones added. "And I think what I would encourage BPA is to, as we move into this 212 proceeding, not subordinate that effort to the 212 effort to the extent possible. I would encourage BPA to continue supporting that in parallel."

'Inherently Speculative'

BPA customers participating in the workshop, such as Portland General Electric, also requested that the agency clarify its proposed readiness criteria intended to weed out speculative projects.

Some of the new proposed updates to planning processes include readiness criteria and a new Network Integration Transmission Service initiative where any new forecast increase of 13 MW or more during any year would require participation in commercial planning. (See *BPA Transmission Pause Questioned During Workshop*.)

The Pacific Northwest Renewable Interconnection & Transmission Customer Advocates (PRITCA), a coalition whose members constitute more than 25% of the current BPA interconnection queue, voiced concern over BPA's commercial readiness criteria.

"Bonneville Transmission is excellent at what they do, but they're not a commercial enterprise, and so shouldn't be picking winners and losers on the basis of these kinds of rather arbitrary standards," said Eric Christensen, an attorney with Beveridge & Diamond, which represents PRITCA.

Christensen argued that commercial readiness criteria are anticompetitive and that all "projects are inherently speculative," noting that several things can go wrong during the permitting process, such as financing or issues with the landowner.

"At the end of this process, we should be promoting generation, market competition," Christensen said. "That, of course, has been the policy for decades now in the electric utility industry. And the [Open Access Transmission Tariff] platform is a stable platform that should be promoting competition and promoting market liquidity."

"The end state that we would like to see, and I think Bonneville's core customers would like to see, as well, is that there is a broad choice of developers of renewable projects that they can choose from when they have to fill their portfolios," Christensen said. "And so anything that restricts that artificially impacts market liquidity and makes it more likely that consumers will be harmed." ■

CTR Plans 500-MW Geothermal Project in Lithium Valley

Described as One of the Largest Baseload Renewable Energy Projects in the U.S.

By Elaine Goodman

Controlled Thermal Resources has taken a step forward on its plans to build a 500-MW geothermal energy plant in California's Lithium Valley, where it is eyeing co-location of manufacturing or data centers.

CTR announced Sept. 9 that it is partnering on the geothermal project with Baker Hughes, an energy technology company. Baker Hughes will supply high-temperature drilling technologies, power systems and digital field services.

The project location is near the Salton Sea in the Imperial Valley region of Southern California — an area that's been dubbed Lithium Valley. Not only is the region a known geothermal resource area, but brines produced there during geothermal electricity generation have been found to be rich sources of lithium.

In fact, the region may have enough lithium to allow the U.S. "to meet or exceed global lithium demand for decades," the Department of Energy said previously. (See *Salton Sea Could Supply Lithium Needs for Decades, Study Finds*.)

CTR's Hell's Kitchen project is a combination of advanced geothermal power generation and critical minerals extraction.

The goal for Stage 1 of the project is 50 MW of geothermal energy and 25,000 metric tons per year of lithium hydroxide.

A conceptual map for CTR's campus in Lithium Valley includes several "co-location" sites for to-be-determined applications. | *Combined Thermal Resource*

Interconnection Delay Bypass

From there, geothermal generation will be expanded in stages, up to an additional 500 MW. The expansion will support hyperscale data center growth and advanced battery manufacturing "with the capacity to accommodate behind-the-meter, direct-source baseload power, bypassing grid interconnection delays," CTR CEO Rod Colwell said in a July project update.

"Hyperscale data center and AI demands are surging, but they cannot run on intermittent renewables," Colwell said in a statement. "The Hell's Kitchen project will provide 500 MW of baseload energy to meet this demand."

Maria Claudia Borras, chief growth and experience officer at Baker Hughes, called the 500 MW geothermal plant "one of the largest baseload renewable energy projects in the United States."

Commenting on the CTR project, California Gov. Gavin Newsom said the state "continues to build more clean energy, faster."

"Together with partners like Controlled Thermal Resources, we're advancing a vision for Lithium Valley that promises to become a global source of critical minerals while also powering a new economic boom for the region," Newsom said in a statement.

The CTR campus is one piece of Imperial County's Lithium Valley Specific Plan. When finalized, the plan will provide a framework across 51,000 acres for clean energy, advanced manufacturing and data centers.

Also in Lithium Valley, data center developer CalEthos is planning a 315-acre campus for clean energy-powered data centers.

CTR is close to making a final investment decision on Stage 1 of the Hell's Kitchen project, and construction could start in 2026, a company spokesperson told *RTO Insider*.

CTR has a 40-MW power purchase agreement with the Imperial Irrigation District as well as lithium supply agreements with major U.S. auto manufacturers.

> **Why This Matters**
>
> Data centers typically need continuous power, and a large geothermal project may provide the clean baseload power they're seeking.

As for the 500-MW geothermal project, CTR plans to build it in 50- to 100-MW increments. The first stages may be complete in the late 2020s, the company said.

Federal Policy Shifts

The buildout for CTR's Lithium Valley campus includes several co-location sites, according to conceptual plans. The co-location sites could accommodate hyperscale data centers, precursor cathode active material production or battery manufacturing, according to the spokesperson.

Permitting work also is underway. In June, Hell's Kitchen formally received a Fast-41 Covered Project designation. FAST-41 is an initiative to streamline federal permitting through a predictable and transparent process.

CTR's plans may also get a boost from recent shifts in federal policy.

The One Big Beautiful Bill Act directs incentives and funding toward projects "that can deliver domestic baseload energy security, critical minerals, manufacturing capacity and supply chain resilience," Colwell said in his July update.

CTR recently took part in a series of high-level meetings in Washington, D.C. Colwell said the meetings "confirmed CTR's alignment with national priorities." ■

Pacific NW on Track to Meet Energy Savings Goals, NWPCC Finds

Region Saved 160 aMW in 2024

By Henrik Nilsson

The Pacific Northwest is on track to meet energy efficiency goals set in the Northwest Power and Conservation Council's 2021 power plan after having saved 160 aMW through improvements in 2024, the council said in a news release.

The 160 aMW in 2024 is up from 157 aMW in 2023. The region has saved 465 aMW since the 2021 power plan was adopted in February 2022, putting it on track to hit the plan's target of 750 to 1,000 aMW by 2027, the council stated in the Sept. 11 release.

"The council's power plans protect the Northwest electricity grid's reliability and adequacy, and cost-effective energy efficiency has been a crucial part of our strategy," council board member K.C. Golden, who represents Washington, said in a statement. "The region is making key progress on our most recent plan's target, but we have more work to do in the next two years. Acquiring the full target by 2027 will achieve the greatest benefit for the Northwest's electricity grid and energy consumers in our region."

Approximately 39 aMW of the 160 aMW in savings came from the Bonneville Power Administration, according to the news release.

The *results* are based on an annual survey conducted by the council's advisory committee, the Regional Technical Forum. Participants in the survey include BPA, the Energy Trust of Oregon, the Northwest Energy Efficiency Alliance, and investor- and consumer-owned utilities in Washington, Idaho, Oregon and Montana.

Commercial buildings accounted for 50% of the savings in the 2024 survey, while the industrial sector accounted for 26%, the residential sector 22% and the agricultural sector 2%.

The region has increased spending on energy efficiency over the past three years. It invested $386.7 million in 2022, $456.2 million in 2023 and $580.6 million in 2024, the council said.

"This increase in funding comes after a period of declining investment in this resource," according to the news release. "This trend likely reflects the renewed need for energy efficiency in meeting regional load growth. Budgets are forecast to grow by 12% in 2025, compared to 2024 levels. Continuing this trend will be important to achieving the 2021 plan's full target by 2027."

brewbooks, CC BY-SA 2.0, via Wikimedia Commons

Why This Matters

The numbers indicate the Pacific Northwest is on track to meet cost-effective energy efficiency targets in the council's 2021 plan.

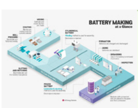
The region has saved 8,042 aMW over the past 45 years, according to the council.

The savings report comes as the council prepares its ninth power plan, which will have a 20-year outlook for the region's grid.

The council is required under the Northwest Power Act "to develop a plan to ensure an adequate, efficient, economical and reliable power supply for the region," according to its website. NWPCC publishes a plan every five years, and the goal is to have a draft ninth power plan by July 2026 and a final version by the end of that year. (See *NWPCC's Initial Demand Forecast Sees Sharp Growth for NW*.)

"The council's power plans and collaboration with regional partners have made the Pacific Northwest a national leader in acquiring cost-effective energy efficiency," Margi Hoffmann, Oregon council member, said in a statement. "Efficiency saves consumers and businesses money on their energy bills, makes our homes safer and more comfortable, and helps ensure the Northwest's power supply continues to be adequate and reliable." ■

West news from our other channels



CEC Awards $28M for New Battery Facility in Hayward

NetZero Insider

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

Texas PUC Approves Entergy Gas Plants, Caps Costs

Mobile Generators Being Synchronized to Grid in San Antonio

By Tom Kleckner

Entergy Texas CEO Eliecer Viamontes discusses the utility's power plant proposal with Texas Gov. Greg Abbott in 2024. | *Entergy Corp.*

Texas regulators have approved Entergy Texas' request to build two natural gas-fired generating units in MISO's portion of the state, but they limited the construction costs eligible for recovery to a combined $2.4 billion.

Thomas Gleeson, the Public Utility Commission's chair, filed a *memo* Sept. 10 outlining his proposal to protect ratepayers from "bearing the burden of … potentially higher costs" during construction. In doing so, Gleeson rejected an administrative law judge's recommendation to deny Entergy's application (*56693*).

"I think the proper thing to do on the cost cap is to impose a hard cost cap of $2.4 billion," he said during the PUC's Sept. 11 open meeting.

The ALJ *found in June* that, while all parties agreed Entergy had shown a "significant near-term need" for additional capacity, it had not demonstrated the two gas units were a cost-effective alternative to meet that need. The judge recommended Entergy's application be denied as it did not meet its burden of proof.

However, the judge said also that Entergy had demonstrated an "imminent" need for additional capacity as early as 2028, leaving little time to secure different resources. It said the PUC could approve Entergy's Dispatchable Portfolio, as it has been labeled, but that it should impose certain conditions of cost recovery.

The PUC applied conditions in the order requiring weatherization and permit approval for future implementation of hydrogen operations and carbon capture and storage.

Entergy Texas *filed an application* for approval to build the two plants in June 2024, saying they were part of the company's "urgent need" to add 40% more generation capacity in four years in the face of "extraordinary" economic and population growth in Southeast Texas.

"We've heard directly from our customers and communities about the need for more power to support our rapidly growing region, and these facilities will deliver just that," Entergy Texas CEO Eliecer Viamontes said in a *statement*.

The plants will be capable of providing 1,207 MW of energy and will generate a combined $2.74 billion in regional economic activity during construction, Entergy said. The company said the units are expected to be in service by 2028.

Legend Power Station, near Port Arthur in southeast Texas, is a 754-MW combined cycle turbine facility. It will be carbon capture-enabled and feature a hydrogen-capable combustion turbine.

Lone Star Power Station is a 453-MW hydrogen-capable combustion turbine facility near Cleveland, northeast of Houston.

Under the terms of the PUC's approval, Legend will be limited to $1.6 billion and Lone Star to $799 million in recoverable costs.

An Entergy Texas spokesperson said both projects have been accepted into MISO's new Expedited Resource Addition Study process (ERAS). "We expect their generator interconnection agreements to be available next year," she said.

However, the projects do not appear on the list of *10 finalists* to enter the first ERAS cycle. MISO plans to accept another round of applications for a second cycle in early November and begin studies in December. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class*.)

Legend and Lone Star are part of Entergy Texas' *Southeast Texas Energy Plan*, also known as STEP Ahead. The six-step plan aims to add 1,600 MW of capacity to the grid by 2028 along with transmission and grid-hardening projects.

Why This Matters

The Texas PUC's cap on the two natural gas plants is designed to protect ratepayers from cost overruns.

Commissioner Kathleen Jackson agreed with Gleeson in the 2-0 decision. Commissioner Courtney Hjaltman recused herself from the discussion and vote.

Mobile Gens Synchronized

ERCOT legal staff told the commission that CPS Energy and LifeCycle Power have interconnected eight of the 15 mobile generators that have been moved from Houston to San Antonio to address a transmission constraint.

Nathan Bigbee said the remaining units are expected to be synchronized and available for ERCOT's dispatch by mid-October, two months later than originally planned. All 15 30-MW units will be dispatched only during emergency conditions through March 2027.

The units originally were leased from LifeCycle Power by CenterPoint Energy in Houston. ERCOT says the generators are necessary to mitigate emergency load-shed that may be necessary to avoid overloads of a generic transmission constraint. It became apparent in February that the grid operator would not be able to extend reliability-must-run agreements to two aging CPS gas-fired units. (See *ERCOT Board OKs Mobile Generators in San Antonio*.)

ESRs as 'Stand-alone' Resources

Commission staff recommended that energy storage resources (ESRs) be included in the PUC's first proposed rulemaking on net metering arrangements involving a large load co-located with an existing generation resource (*58479*).

Legislation passed during the 2025 biennial session requires ERCOT to study the system impacts of net metering arrangements involving "stand-alone" resources as of Sept. 1, 2025, and new large-load customers. On Sept. 2, staff posted a *market notice* that included an attachment listing the types of stand-alone resources.

Bigbee said he found "near-universal" support for including ESRs during a Sept. 2 workshop on net metering.

"We believe that's a defensible approach as well," he said. "So, if it's the commission's will, we'd be happy to include them on the list."

The commission will discuss the proposed rulemaking at its Sept. 18 open meeting.

The PUC also:

- *Remanded* back to docket management a revised order on CenterPoint's system resiliency plan. In a *memo*, Hjaltman said the utility's proposed transition from a five-year to a three-year vegetation management trimming cycle lacked key information supporting cost recovery. She requested supplemental evidence to justify the plan's approval and a proposed cost-recovery mechanism. An ALJ *filed* the revised order in July (*57579*).
- Delayed action on Entergy Texas' proposed 500-kV single-circuit transmission line in Northeast Texas. The 150-mile line has *drawn opposition* from local landowners, who requested a rehearing of the State Office of Administrative Hearings' *decision* to recommend a certificate of convenience and necessity for the line. The project's various routes range from 131 to 160 miles and its costs are projected to be between $1.33 billion and $1.52 billion (*57648*). ■

Rendering of Entergy's proposed Legend Power Station and Lone Star Power Station | *Entergy Corp.*

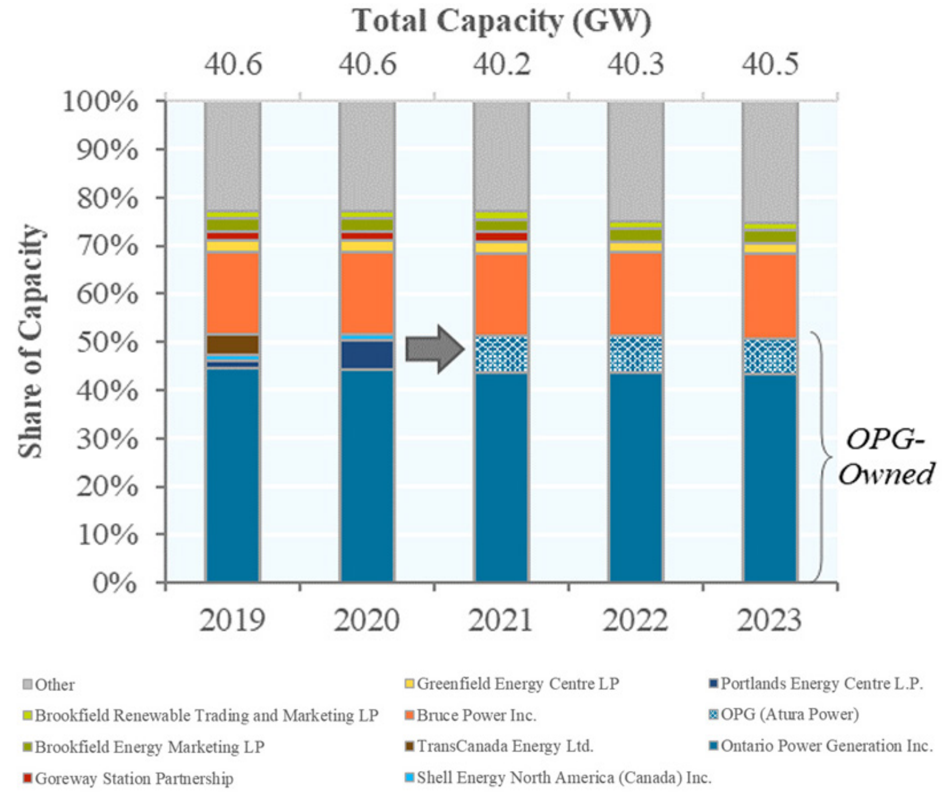
Ontario Market Monitor Revamps Techniques for IESO Nodal Market

By Rich Heidorn Jr.

Ontario's energy regulator is learning new ways to identify inefficiencies and malign behavior under IESO's Market Renewal Program, which introduced LMPs and a financially binding day-ahead market.

The Ontario Energy Board *said* its Market Surveillance Panel (MSP) has developed "new tools and indicia" in response to IESO's nodal market, which launched May 1. (See *Ontario Nodal Market Nearing 'Steady State' After Nearly 4 Months*.)

OEB said the MSP will continue to track "market participant conduct and the efficiency and competitiveness" under the new market. "However, the complexities of the renewed markets have increased relative to the legacy markets," it said.



Registered capacity by market participant, 2019-2023 | *Ontario Energy Board Market Surveillance Panel State of the Market Report 2023*

MSP Members, Recommendations

The MSP, which transferred from IESO to the OEB in 2005, has *three members*: Chair Ken Quesnelle, former vice chair of the OEB and former chair of the Electricity Distributors Association; Brian Rivard, an adjunct professor at the Richard Ivey School of Business at Western University and a principal at Charles River Associates and IESO's former director of markets; and Darren Finkbeiner, IESO's former director of rule compliance and market surveillance. The MSP is supported by OEB staff and uses data provided by IESO's Market Assessment Unit.

The MSP's previous recommendations have been adopted by both the OEB and IESO — including some of the changes implemented under Market Renewal.

Why This Matters

Previous recommendations by the Market Surveillance Panel have led to action by IESO's Market Assessment and Compliance Division, resulting in settlement repayments and financial penalties.

MSP reports also have led to action by the IESO's Market Assessment and Compliance Division, resulting in settlement repayments and financial penalties.

New Market: Locational Marginal Prices and Single Clearing

Under Market Renewal, day-ahead market (DAM), pre-dispatch and real-time prices are calculated at about 1,000 LMP nodes, instead of Ontario-wide. With a financially binding DAM, there now is a single dispatch schedule.

Here are some of the other changes under the new market, and how the MSP plans to respond:

- Congestion Management Settlement Credit (CMSC) payments: CMSC payments encouraged participants to follow dispatch during transmission constraints under the former two-schedule system. They were replaced by LMPs — which embed the cost of congestion — and make-whole payments (MWPs), which compensate for lost opportunity costs when IESO dispatches resources out-of-merit.
- While continuing to use the highest-cost peaking natural gas generators as an initial screen, the MSP also will use statistical models to identify anomalous LMP differences not explained by losses or congestion. "This type of monitoring analysis will replace the monitoring of legacy CMSCs to assess potential market flaws or inappropriate conduct not explained by grid conditions," OEB said.
- The MSP will monitor large MWPs, as well as MWPs to individual market participants or for specific facilities, to identify anomalous results or market manipulation. A new MWP Anomaly Index will put MWP levels in perspective relative to resource margins in the day-ahead and real-time markets. The index is calculated as: MWP ÷ (Resource Revenues + MWP) x 100. "This metric will tend to filter out changes in the level of MWPs due to variations in fuel costs … as well as those due to the frequency with which particular types

of units are committed, to better identify potential anomalies and changes in behavior," OEB said.

- Reserve Shortage Penalties: IESO now is using reserve shortage penalty prices (a maximum operating reserve area penalty price, a penalty price for 30-minute operating reserve and an area minimum operating reserve penalty price) to ensure that day-ahead, pre-dispatch and real-time calculation engines respect mandatory reserve requirements, that prices reflect those requirements, and to encourage market participants to meet their reliability obligations.
- The MSP will review all applications of reserve shortage penalty prices to identify the causes of the shortages and potential anomalies in market design or inappropriate market conduct.
- Operating Parameters: The renewed market requires non-quick-start gas generators, hydro and variable generation to submit additional data on their operating parameters.
- The MSP will monitor changes to individual facility data for their effects on dispatch and economic efficiency. "Changes to this data may be part of a broader strategy by a market participant to inappropriately influence market outcomes, MWPs and prices to the benefit of the participant [at the expense] of other market participants and consumers," OEB said.

IESO Market Power Mitigation

IESO introduced a three-pronged market power mitigation (MPM) scheme to prevent suppliers from market power due to their location on the transmission grid:

- An ex-ante (before-the-fact) approach applied in the day-ahead, pre-dispatch and real-time scheduling processes to police the energy and operating reserve markets.
- An ex-ante mitigation process to prevent market power in the settlement of make-whole payments.
- An ex-post (after-the-fact) mitigation of market power to address physical withholding and economic withholding on uncompetitive interties.

OEB's surveillance unit will evaluate the effectiveness of the MPM framework through its own three-part market power screen: a conduct test (for withholding activity); a material price impact test (determining whether the conduct of a market participant significantly impacted market prices), and a profitability test (whether the MP's conduct benefited the participant).

Market Control Entities

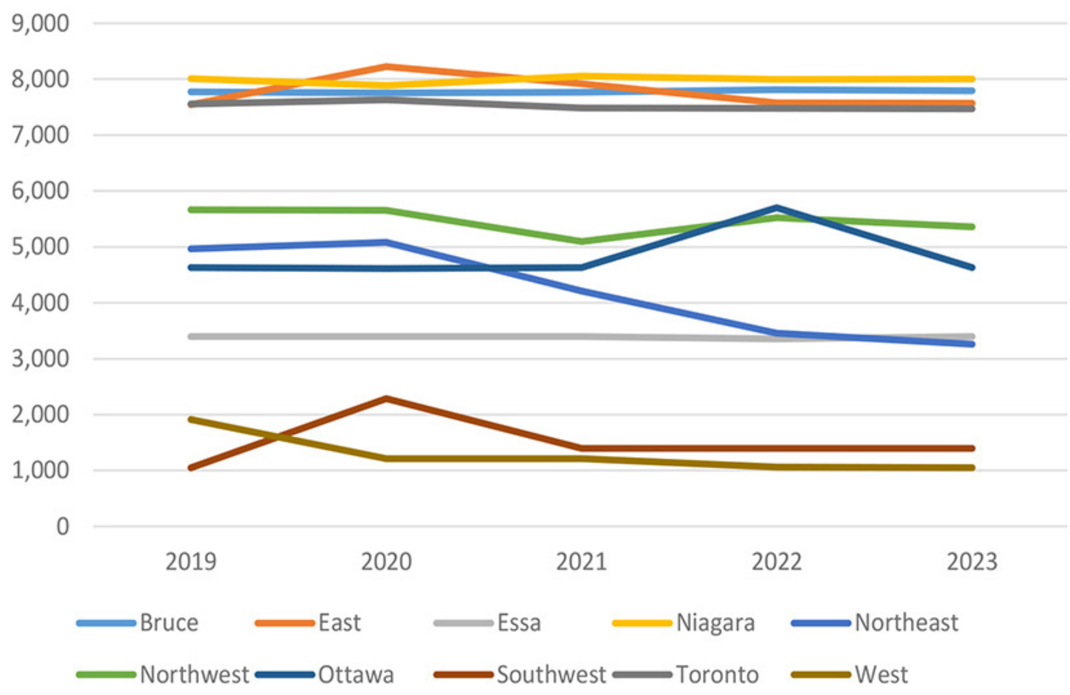
IESO will use data from market control entities — companies that control generators and other market participants (dispatchable and price responsive loads, electricity storage resources, energy traders or virtual traders) — to assess physical withholding by examining in aggregate the offer quantities of resources that share a common MCE.

The MSP will incorporate the data in calculating structural measures of competition such as the Herfindahl–Hirschman Index and Residual Supplier Index.

OEB said the MSP will monitor persistent price differences between DAM and RT to ensure they are not a result of illiquid markets or gaming.

New Tool for IESO

To assess the effectiveness of the renewed markets and identify potential solutions to unintended outcomes, the IESO developed the Market Analysis and Simulation Toolset (MAST), which enables it to conduct "but-for" analyses of market outcomes through inputs into the market calculation engines.



Herfindahl–Hirschman Index of registered capacity per zone, 2019-2023. Except for the West and Southwest zones, HHI scores were greater than 1,800 throughout the period, indicating highly concentrated zones. | *Ontario Energy Board Market Surveillance Panel State of the Market Report 2023*

OEB said the MSP also may use MAST in its assessment of the market's efficiency in its annual *State of the Market* reports, as well as to analyze anomalous market outcomes and identify potential market flaws.

"In an upcoming State of the Market report, after sufficient data has been collected to permit such an analysis, the MSP intends to provide a comparison of the relative efficiency and competitiveness of the legacy markets to the renewed markets," OEB said. "This analysis is not intended to be an audit of MRP at achieving its objectives. Instead, it is intended to offer insights into the overall efficiency implications of the changes, including where certain efficiencies may or may not have been realized and where improvements in design may be desirable." ■

ISO-NE Faces Criticism over Accountability, DER Policy at Public Meeting

By Jon Lamson

Why This Matters

ISO-NE continues to face pressure from activists to open up the NEPOOL stakeholder process to the public.

Several panelists and public commenters at the quarterly meeting of the ISO-NE Consumer Liaison Group criticized the RTO over its record on accountability and accessibility, as well as its policy related to distributed energy resources.

The tenor of CLG meetings has been critical of ISO-NE since a coalition of climate activists took control of the group's coordinating committee in 2022. (See *Climate Activists Take Over Small Piece of ISO-NE*.) Many of the same themes and critiques from past CLG meetings resurfaced as the group met in Manchester, N.H., on Sept. 11 for its third-quarter meeting.

Marla Marcum, an activist associated with the climate group No Coal No Gas, criticized the closed nature of NEPOOL stakeholder proceedings. She said grassroots climate activists are interested in engaging in discussions around ISO-NE's ongoing overhaul of its capacity market but are prevented from meaningfully participating in discussions because they are not members of NEPOOL. (See *ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes*),

Responding to the criticism, Anne George, ISO-NE's chief external affairs and communications officer, said all materials and minutes from stakeholder meetings are posted publicly, and members of the public are welcome to submit input for review by the RTO's market development team.

"The ability for us to throw our comments into the whirlwind, no matter how good they are, is not the same as being able to meaningfully participate in this process," Marcum responded.

Meanwhile, New Hampshire Consumer Advocate Don Kreis repeated his past criticisms of the RTO for being incorporated in Delaware, arguing that it would be more accountable to ratepayers in the region if it was incorporated in New England.

The meeting also featured a panel on how ISO-NE can help address energy affordability. Several panelists urged the RTO to do more to help demand response and DERs participate in its markets.

Allison Bates Wannop, a lawyer and DER advocate with experience working in all U.S. RTOs, said she has "found ISO-NE to have a preference for not enabling distributed energy resources."

While she praised the work of ISO-NE staff, she said the RTO generally appears "distrustful" of DER aggregators and has been overly conservative in its compliance with FERC Order 2222, which requires RTOs to lower barriers to DER aggregators to participate in wholesale markets.

Bates Wannop highlighted FERC Commissioner Allison Clements' *concurrence* on FERC's ruling on ISO-NE's original Order 2222 compliance proposal, in which Clements strongly criticized the RTO for putting forward "a proposal that was almost universally panned by prospective market participants seeking to integrate behind-the-meter resources into its markets." (See *FERC Gives ISO-NE Homework on Order 2222*.)

Clements wrote in her concurrence that ISO-NE's submetering proposal for DER aggregations is significantly more burdensome for aggregators than the proposals of other RTOs, adding that ISO-NE's unique circumstances do not "necessarily provide an excuse for not adopting an approach similarly to those successfully pursued elsewhere."

Also during the panel, Kreis asked speakers about a *recently passed* bill directing the New Hampshire Department of Energy to study the possibility of withdrawing from ISO-NE. Multiple speakers expressed hope that the study would allow for a constructive look at improving the RTO.

However, several speakers expressed skepticism about the viability of leaving ISO-NE, along with the benefits this move would have for New Hampshire consumers.

Henry Herndon, acting general manager of the Community Power Coalition of New Hampshire, said the bill poses an "interesting opportunity to ask questions."

Bates Wannop said that "while I don't think New Hampshire should leave ISO-NE, I think constantly asking the question how it can be reformed is important."

Imagining an Ideal RTO

Also at the CLG meeting, Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School, delivered a keynote speech centered around imagining an ideal grid operator for the region, unincumbered by history, compromises and agreements that have led to the current structures and roles of ISO-NE and NEPOOL.

"ISO-NE's governance is tied to the peculiar history of New England utilities, rather than any particular attributes," he said.

Peskoe noted that, due to the history of ISO-NE's formation, New England transmission owners participate in ISO-NE voluntarily and retain filing rights over the revenue requirements for their own system. Meanwhile, candidates for the ISO-NE board of directors are nominated by a committee made up of current board members and NEPOOL participants and are approved by the NEPOOL Participants Committee and the board.

If the region was starting from scratch, Peskoe said, it still would be beneficial to have some form of nonprofit regional entity to ensure cost and operational efficiency across the region's grid, but he would like to see greater independence from market participants and a stronger emphasis on innovation.

While the hypothetical, redesigned RTO would remain a non-regulatory independent entity, *Peskoe* said the states could take on a larger role. He floated the idea of allowing each governor to nominate two non-state employee candidates to the ISO-NE board. ■

ISO-NE Kicks off Talks on Accreditation, Seasonal Capacity Changes

By Jon Lamson

ISO-NE kicked off discussions on the second phase of its capacity auction reform (CAR) project at the NEPOOL Markets Committee on Sept. 10, beginning long-awaited talks on accreditation and seasonal capacity auction changes.

Changes to capacity accreditation would directly affect the capacity market revenues available to resources in the region, which makes it a particularly hot topic for New England stakeholders.

The second phase of the CAR project also includes a proposal to split ISO-NE's annual capacity commitment period (CCP) into six-month summer and winter seasons with separately procured capacity.

ISO-NE is aiming to finalize and file the CAR seasonal and accreditation (CAR-SA) changes by the end of 2026. The RTO is nearing the end of its work on the first phase of the CAR project (CAR-PD), which is focused on transitioning from a forward to a prompt capacity auction, along with resource retirement changes. (See *Stakeholders Mixed on ISO-NE Prompt Capacity Market Proposal*.) Both phases of the CAR project are intended to take effect for the 2028/2029 CCP.

The RTO's CAR effort began in 2022, but it paused the work for an extended period to expand the scope of the project to include changes to the auction format.

The proposed accreditation reforms would base each resource's capacity value on "how an increment of capacity from the resource would reduce the total amount of expected unserved energy."

Steven Otto, manager of economic analysis at ISO-NE, said this approach should better account for resources' actual contributions to regional reliability, improving market efficiency and providing more accurate signals for resource entry and exit.

"The [marginal reliability impact] framework, in conjunction with the other elements of the CAR proposal, will help the capacity market meet its core objectives of reliability, sustainability and cost-effectiveness by accrediting resources based on their expected performance during simulated hours where additional available capacity would mitigate or prevent load shed," Otto said.

Fore River Energy Center in Weymouth, Mass. | *Calpine*

Why This Matters

Accreditation changes are intended to better prepare the region for a shifting resource mix and risk profile and would directly affect resources' capacity market revenues.

In the new format, each resource's accreditation would be subject to change as the resource mix evolves, which could incentivize a more diverse resource mix. For example, as the proliferation of solar generation reduces reliability risks during early evening hours in the summer, incremental additions of solar capacity would reduce the accreditation of all solar resources.

Under the existing rules, "resources' [qualified capacity] values are largely static, which may cause disparities between resources' capacity market compensation and their resource adequacy contributions as system conditions evolve," Otto said.

One key component of the accreditation reform proposal will be the calculation of the winter gas constraint, intended to reflect the region's limited access to gas during cold periods.

Otto noted that ISO-NE plans to develop a "market-based gas constraint for the winter season," which would be based on separate demand curve for gas resources that lack firm fuel contracts.

ISO-NE wrote in a 2024 *memo* that the approach "would decrease the amount of gas capacity procured in the winter … and would pay that capacity a lower price."

Though the details of this market constraint have yet to be developed, the mechanism will likely reduce accreditation values for gas resources that do not have firm fuel arrangements, creating incentives for generators to secure their fuel supply.

Stakeholder Proposals

Also at the MC, stakeholders proposed several changes to ISO-NE's CAR-PD proposal.

Andrew Gillespie, director of governmental and regulatory affairs at Calpine, *made the case* for ISO-NE to change its formula for calculating the capacity offer price threshold (COPT) in the capacity market. Market participants that bid above this threshold are subject to market power review by the Internal Market Monitor and must submit a detailed cost workbook.

For the 2028/2029 CCP, ISO-NE plans to base the threshold on the average of the clearing price from previous Forward Capacity Auction (FCA) and a clearing price forecast for the upcoming auction.

Gillespie argued that relying on the clearing price from previous capacity auction, which would have been held about four years earlier, inadequately accounts for the recent spike in capacity scarcity hours.

Elaborating on a proposal outlined at the MC in August, he said the RTO should instead rely on the opportunity costs, as defined by a formula multiplying the balancing ratio by the performance payment rate by the expected number of capacity scarcity hours. (See "Seller-side Market Power," *NEPOOL Nears Vote on 1st Phase of ISO-NE Capacity Auction Reforms*.)

Relying on this formula would significantly increase the threshold price, Gillespie said. He estimated that the threshold price for the past three auctions would have been more than double the auction clearing price for the past three FCAs.

He said recent FCAs have underestimated the number of scarcity hours and added that, "without modification to the threshold price, suppliers that submit an offer based on 'opportunity costs' may be mitigated by IMM."

Ben Griffiths, vice president of wholesale market policy for LS Power, offered an *alternative proposal* for the threshold, proposing to rely on the most recent annual reconfiguration auction clearing price instead of the most recent FCA clearing price.

He said this proposal should be applied solely to the 2028/2029 CCP and would serve as a "one-time, targeted fix that it preserves the broader tariff framework and leaves the general COPT formula unchanged for future auctions."

Griffiths added that the annual reconfiguration auction clearing price would be a "reasonable substitute" for the FCA clearing price, since annual reconfiguration auctions "are deliberately designed to mirror the FCA in many of their mechanics."

Also at the meeting, FirstLight Power's Tom Kaslow proposed *tariff changes* to impose Pay-for-Performance charges on exports during capacity scarcity events. ISO-NE also advocated for this change in its annual report, published earlier this year. (See *ISO-NE Monitor Discusses Market Trends, Energy Transition*.)

In response to the proposal, some stakeholders have advocated for explicit language exempting capacity-backed exports from performance charges. ■

MISO Discloses $280M Error, Over-procurement in 2025/26 Capacity Auction

MISO Says Continuing Error Dates Back to 2017

By Amanda Durish Cook

MISO said a yearslong software error caused it to clear more capacity than intended in past capacity auctions and resulted in an approximate $280 million impact to market participants in this year's auction.

MISO *said* it uncovered the coding error — which had gone unnoticed since 2017 — in a third-party vendor's work. The error caused MISO to clear additional capacity at higher auction clearing prices in the 2025/26 Planning Resource Auction (PRA), MISO said.

That likely means the error produced higher prices and higher reserve margin requirements in MISO's auctions all the way back to the 2018/19 planning year.

MISO said the error calculated its loss-of-load expectation (LOLE) using an "all-hours" methodology, rather than the tariff-defined "daily peak hour" methodology, leading this year's auction to clear more capacity than intended.

MISO's tariff defines LOLE as "the sum of the loss-of-load probability for the integrated daily peak hour for each day of the year." As currently defined, a day with a loss-of-load event is counted in MISO's LOLE calculations only if the event happens during the hour with daily peak load.

MISO said it discovered the error in June while running simulations of LOLE in preparation for the very change the software error induced. MISO wants to change its LOLE definition from one that's expected only on the daily peak hour (the "daily peak hour" methodology) to one that could crop up at any hour in the day (the "all-hours" methodology). MISO has said that increasingly, generation emergencies can strike at any time.

MISO made a FERC *filing* in late August to transition from the daily peak hour to the all-hours LOLE methodology. It plans to use the approach formally beginning with the 2026/27 planning year if it receives FERC permission.

In MISO, the LOLE is the primary factor that determines demand curves in the capacity auction, which has a direct effect on clearing prices.

MISO said while it won't specify the exact number of additional megawatts that ended up clearing, the all-hours software approach led to an estimated 1 to 2% over-procurement of resources in the case of the 2025/26 auction.

In an email to *RTO Insider*, MISO said the $280 million financial impact from the over-procurement will extend to companies that entered the auction long or short on megawatts. That means if a market participant was paid based on auction results, then they must pay back a portion of their earnings to MISO. Market participants who were charged, on the other hand, can expect a refund from MISO.

MISO added that it will make only "paper adjustments" without financial impact for market participants that netted out their generation and load in the auction.

Settlement adjustments could affect any generator with accredited capacity in the 2025/26 PRA, MISO added.

MISO acknowledged that planning reserve margin requirements likely have been skewed since 2018 because of the software error. However, the RTO noted that its tariff limits evaluation of a continuing error to a one-year look-back period.

MISO's seasonal planning reserve margin requirements for the 2025/26 planning year are 7.9% in summer, 14.9% in fall, 18.4% in winter and 25.3% in spring.

MISO said it will not retroactively alter 2025/26 capacity clearing prices to correct the error.

"MISO is not rerunning or resettling the PRA. We are not accepting new bids or establishing a new auction clearing price. Instead, adjustments will be made via settlements, not through price recalculation," MISO said in a statement to *RTO Insider*.

Why This Matters

A software error discovered in the complex calculations for MISO's loss-of-load expectation likely means that the RTO has secured more capacity than necessary in auctions dating back to the 2018/19 planning year.

The 2025/26 auction cleared at $666.50/MW-day in summer, $69.88/MW-day in spring, $33.20/MW-day in winter and $91.60/MW-day in MISO Midwest and $74.09/MW-day in MISO South for fall. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

MISO said it's sending notices to generation companies about the financial impacts to their portfolios. It said it plans to "issue all adjustment statements or invoices" by Sept. 25.

MISO told *RTO Insider* that it would not disclose the vendor responsible for the error. The grid operator did not comment on whether it would continue to use the vendor's services. MISO said at the time it discovered the error, the vendor "confirmed the software has never calculated LOLE based on the daily peak hour methodology since implemented in the 2018/19 PRA."

MISO said it made a self-report with FERC and notified its Independent Market Monitor and Board of Directors. The grid operator also said it's "working to strengthen validation and product testing for critical software."

MISO leadership plans to discuss the software error and ongoing correction efforts with its board during a Sept. 16 meeting in Detroit, part of its quarterly Board Week. ■

Consumers Energy to Offload 13 Michigan Hydro Dams to Investment Firm for $1 Each

By Amanda Durish Cook

Why This Matters

Consumers Energy will sell its fleet of hydroelectric dams for $1 each to an out-of-state investment firm. The utility has long said the mostly century-old dams are becoming too expensive to operate.

After years of looking for a buyer, Consumers Energy announced it struck a $13 deal to sell its fleet of 13 hydroelectric dams in Michigan to a Bethesda, Md., private equity firm.

Consumers Energy agreed to sell the collection of century-old dams for $1 apiece to a newly formed subsidiary of Hull Street Energy in a Sept. 9 purchase agreement. The dams are situated on five rivers across Michigan and have a combined installed capacity of 132 MW, though they currently generate only about 50 MW, according to Consumers.

In a release, Consumers said the sale will reduce long-term costs for its customers and ensure the continued safe operation of the dams.

Consumers has long said maintaining the dams is expensive. The dams were built between 1906 and 1935, making the oldest nearly 120 years old. The utility has acknowledged the dams need significant infrastructure upgrades to remain in compliance with FERC licensing requirements. Consumers estimates that maintaining the dams through a new 30- to 50-year licensing period would cost $1.5 billion. It also has said the dams' hydroelectric output costs nine times more than its other sources of generation.

Hull Street Energy said it has a "long track record of successfully owning and operating hydroelectric facilities" across North America. It said it has acquired and improved 47 hydroelectric assets in the past decade. Many of the facilities are small or midsize run-of-river dams in New England.

The investment firm created subsidiary *Confluence Hydro* to own and manage the dams and acquire other hydro assets.

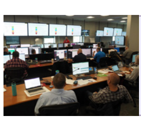
"The firm will leverage its extensive experience and capital resources to upgrade the projects, ensuring the facilities can continue to safely deliver reliable, clean energy to Michigan customers and support economic and recreational opportunities critical to local communities for years to come," Hull Street Energy said in a press release.

Confluence Hydro CEO Ed Quinn emphasized the company's commitment to dam safety and refurbishment in a statement.

"With decades of experience operating hydro facilities, we are committed to preserving and modernizing these important resources to maximize their contribution to the grid," Quinn said, adding that Confluence aims to be "a best-in-class hydro

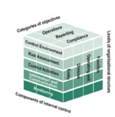
Consumers Energy's Mio Dam on the AuSable River is part of the sale to Hull Street Energy. | *Consumers Energy*

National/Federal news from our other channels



E-ISAC Updates NERC Committee on GridEx VIII Scenario

ERO Insider



NERC Task Force Members Talk Internal Controls Improvements

ERO Insider

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

company — one that protects communities, supports employees, mitigates risk, and delivers reliable, clean energy for the future."

Hull Street Energy was founded in 2014.

The sale agreement dictates that Confluence Hydro enter a contract to sell power back to Consumers Energy from the facilities for 30 years. Confluence said it would seek to renew the dams' federal operating licenses, which begin to expire in 2034.

"We believe a sale of the dams is the best path forward for our customers. This sale balances two important needs: to lower costs for Consumers Energy's customers while continuing to care for communities that depend on the dams," said Sri Maddipati, Consumers Energy's president of electric supply. "After numerous conversations with community members over the last three years to gather insights and feedback, we are confident this sale will preserve the reservoirs that hold the key to economic, recreational and community benefits at each of the dams."

Consumers Energy *hosted* local meetings across Michigan on the fate of the dams beginning in 2022 and issued a request for proposals in early 2024. It also hired Lansing, Mich.-based Public Sector Consultants in 2022 to explore the impacts on communities in the event of partial or full dam removals.

The companies expect the transaction to close within 12 to 18 months pending approval from the Michigan Public Service Commission and FERC for the sale and license transfer for the dams.

Confluence said it plans to hold meetings with employees and affected communities in the coming months. It also said it plans to offer current Consumers Energy hydro employees "equivalent positions" with Confluence.

Bob Stuber, president of the Michigan Hydro Relicensing Coalition, which represents five conservation groups, expressed concern over a private investment firm buying the dams.

Stuber said because the new owner would sell power to Consumers Energy rather than the public, Hull Street cannot be reimbursed for any future investments through the Michigan PSC, possibly making future capital investments in the dams unattractive.

"Consumers acknowledges that these hydropower projects are marginally economical. It is a well-managed corporation, so it begs the question: If Consumers is challenged to turn a profit from these projects, how will another entity be able to, especially without a cost-recovery mechanism?" Stuber asked in a statement to *RTO Insider*.

Stuber said there's also no guarantee Hull Street will continue to meet licensing requirements.

"History has demonstrated that new owners of older hydropower projects in Michigan are not as committed, as shown by the Edenville and Sanford catastrophic dam failures," Stuber said, referring to Boyce Hydro's yearslong negligence that caused the collapse of the Edenville and Sanford dams in Mid Michigan in May 2020. In that case, Las Vegas architect Lee Mueller and family members bought the dams to avoid paying taxes on the sale of an Illinois property. (See *Michigan Dam with Prolonged Safety Issues Fails* and *FERC Terminates More Boyce Hydro Licenses*.) ■

Ameren Resolute in 1st Dibs on Long-range Transmission Projects in Illinois

By Amanda Durish Cook

Ameren Illinois remains adamant that it should have exclusive access to construct nearly $2 billion of MISO regional transmission projects in the state without competition.

In a Sept. 9 filing, the company called the Illinois Commerce Commission, MISO and consumer groups' counter arguments "irrelevant, misleading and without merit" and continued to claim FERC should decide the matter (*EL25-105*).

Ameren argued in a late July petition that Illinois' "first in the field" doctrine is the functional equivalent of a right-of-first-refusal law and gives it *carte blanche* to develop the Illinois portions of the lines in MISO's second, $22 billion long-range transmission plan. (See *Ameren Argues Exclusive Rights to MISO Illinois Competitive Tx Projects*.)

Among others, the ICC has asked FERC to reject Ameren's petition and let the state handle the matter.

"Ameren seeks to accomplish via the commission what it failed to achieve through its lobbying efforts in 2023: the establishment of an exclusive statutory right of first refusal," the ICC said. It added that courts have never construed the doctrine as a ROFR law, and Illinois Gov. JB Pritzker vetoed a ROFR bill in 2023.

The ICC said Ameren is "forum shopping" with FERC to quash transmission competition. It argued that while the "field" doctrine protects incumbent utilities from competition for retail customers and is meant to discourage duplicative utility facilities and stranded assets, the Illinois Supreme Court has explicitly ruled that it is "not to be employed to totally prevent another from entering a contiguous area or, for that matter, even the same territory."

MISO has disagreed with Ameren's claim that it was wrong to put the projects up for solicitation.

"Without a binding determination from an Illinois court or other competent tribunal, it is not clear whether the 'first in the field' doctrine has any application in the specific context presented by this case," the RTO told FERC in late August.

MISO has put two 765-kV *projects* in Illinois from the second long-rang portfolio up for bid: $717.6 million of the $984.6 million Woodford County-Illinois/Indiana State Line project, and the $940.1 million Sub T-Iowa/Illinois State Line-Woodford County project.

But Ameren insisted that protesters haven't been able to prove that the doctrine is not "valid law." It argued in its latest filing that its petition is "specifically limited to an interpretation of MISO's tariff" as to whether the RTO should have put those projects out for bid. Ameren said a determination as to whether Illinois' doctrine constitutes a ROFR is an "underlying" issue.

Construction on part of Ameren Illinois' Coffeen-Roxford project | *Poettker Construction*

Why This Matters

Ameren Illinois claims that FERC doesn't have to interpret state law to decide that MISO should have respected Illinois' 'first in the field' doctrine and assigned parts of two long-range transmission projects directly to the utility.

Ameren said it filed a separate "declaratory action in Illinois state court" to verify its rights to the projects over competitive developers. The utility said it understood that FERC doesn't regulate state transmission siting and said it's not seeking an interpretation of Illinois law, just the commission's "confirmation" that the doctrine is an applicable law that MISO should recognize.

"No interpretation of Illinois law is required by the commission because it is clear that the 'first in the field' doctrine is existing law that applies to electric transmission," Ameren argued. It argued that no ICC hearing is required and that the doctrine has already been "broadly" applied in bus service, telecommunications, moving companies, and water and sewer service.

The utility also noted that FERC "alone has the authority to issue a binding interpretation of MISO's tariff."

Invenergy Transmission and Exelon have agreed with the ICC that Ameren's claim should be resolved by Illinois regulators and courts. The Industrial Energy Consumers of America, the Coalition of MISO Transmission Customers, Electricity Transmission Competition Coalition and the Illinois Industrial Energy Consumers have also urged FERC to dismiss the petition. The consumer groups argued that the doctrine is applied on a case-by-case basis in proceedings after evaluation by the ICC and is not an unmitigated shield from competition. ■

MISO, Stakeholders Appeal to FERC to Leave Long-range Tx Plan Intact

By Amanda Durish Cook

MISO and several stakeholders came to the defense of the RTO's $21.8 billion, 24-project long-range transmission plan (LRTP) portfolio for the Midwest as five Republican states seek to repeal the projects' approval.

The state utility commissions of Arkansas, Louisiana, Mississippi, North Dakota and Montana filed a complaint in late July asking FERC to order MISO to revoke the classification of its second LRTP portfolio and nullify the portfolio's load-ratio share cost allocation. The five states claim MISO and its board erred by advancing transmission projects that will cost more than the value they can provide and said FERC should scrutinize all the RTO's future business cases supporting long-range transmission portfolios (EL25-109).

The states argued that MISO currently has no authority to direct the projects' construction because the projects don't meet the required 1:1 benefit-cost ratio in the RTO's tariff. (See *MISO States Split on FERC Complaint to Unwind $22B Long-range Tx Plan* and *Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan*.)

MISO didn't mince words in a Sept. 9 response. It said the derailment of a 765-kV backbone furnished by the projects would jeopardize it and its states' ability to meet growing electricity demand and swap comprehensive regional planning for a more expensive, piecemeal buildout. MISO said the states made nothing more than a collateral attack on its established planning practices and long-established postage stamp cost allocation method for projects.

"The deficient and misleading complaint filed in this docket puts at risk not only the needed infrastructure resulting from a comprehensive, stakeholder-driven planning process, but also future generation, transmission and large load additions by creating regulatory uncertainty, which the commission, federal and state policymakers and the courts have sought to reduce," MISO said.

Why This Matters

Several utilities, organizations and state agencies told FERC that MISO's $22 billion long-range transmission plan is vital to grid modernization, reliability and — yes — data centers.

The grid operator said the five states advocated for a "haphazard and unrealistic approach to regional transmission planning" that is "profoundly inconsistent" with FERC precedent and Order 1920. MISO added that North Dakota and Montana stand to significantly benefit from the second LRTP portfolio "in exchange for a very small percentage of the costs" and stood by its original 1.8 to 3.5:1 cost-benefit estimate for the total portfolio.

Arkansas, Louisiana and Mississippi are not going to fund any of the projects because MISO South was not part of the LRTP planning exercise. The South is destined for its own long-range planning that is set to begin in 2026.

MISO said it conducted more than more than 300 stakeholder meetings, considered 100 alternative projects and made 500-plus revisions to assumptions in its planning process on the advice of its stakeholders. The RTO also said that the five state commissions didn't attempt to initiate MISO's dispute resolution process while the portfolio was in the draft stages.

Several MISO stakeholders asked FERC to throw out the complaint in other responses posted on the Sept. 9 deadline.

Xcel Energy agreed with MISO's standpoint and said the RTO granted requests from the North Dakota Public Service Commission to model up to nearly 15 GW of additional wind capacity in the state and included more dispatchable resources in the plan, even though the hypothetical megawatts didn't appear in states' generation plans.

Xcel said the second LRTP portfolio is now — "if anything — more essential and more urgent" given that load growth projections have eclipsed what MISO could have predicted in 2024. It said North Dakota was joined in its complaint by "state commissions that either effectively sat out" the planning process (Montana) or states that have "no concrete stake" in the portfolio (Arkansas, Louisiana and Mississippi). The utility argued that now is the time for developers to "go forth and build, without endless trips back to the commission or nonstop second-guessing." Xcel also criticized the states for appearing to demand MISO be a "Soviet-style central planner" that should have planned generation and transmission simultaneously.

IMM Doubles Down that MISO Benefit Calculations are Faulty

However, MISO Independent Market Monitor David Patton again said the RTO overstated its future transmission needs through the 20-year planning future it based the portfolio on.

Patton was a vocal opponent of the second LRTP portfolio throughout 2024 and repeatedly said MISO should consider capacity expansion with fewer intermittent renewable resources and more energy storage and dispatchable generation built closer to the load they would serve. (See *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.) This would obviate the need for 113 GW of intermittent renewable resources by 2042 and reduce costs by $92 billion, he said.

MISO's second future — which the second LRTP portfolio is based on — predicts the RTO operating with 466 GW of nameplate capacity by 2042, broken down into 160 GW of wind generation, 112 GW of solar, 65 GW of natural gas, 41 GW of other generation, 31 GW of battery storage, 12 GW of nuclear, 10 GW of storage, 6 GW of coal and 29 GW of shadowy, "flex" dispatchable resources that will be necessary to meet reliability but aren't currently in member plans.

Patton said the transmission portfolio

"will undermine the market incentives for participants to invest in lower-cost resources and transmission upgrades that would be more efficient and lower MISO's long-term costs." He asked FERC to order the RTO to revise the transmission portfolio based on a more realistic view of the future system and a more thorough benefits assessment.

Patton also argued that the trajectory of members' generation planning is changing, evidenced by the mostly dispatchable energy lining up for MISO's newly introduced expedited queue lane. Patton said the queue fast lane will "substantially" lower the RTO's transmission needs. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class*.)

The Coalition of MISO Transmission Customers agreed with the Monitor that the RTO overstated the benefits of the projects and that it didn't meet a least-regrets planning standard with the portfolio.

8 States vs. 5 States

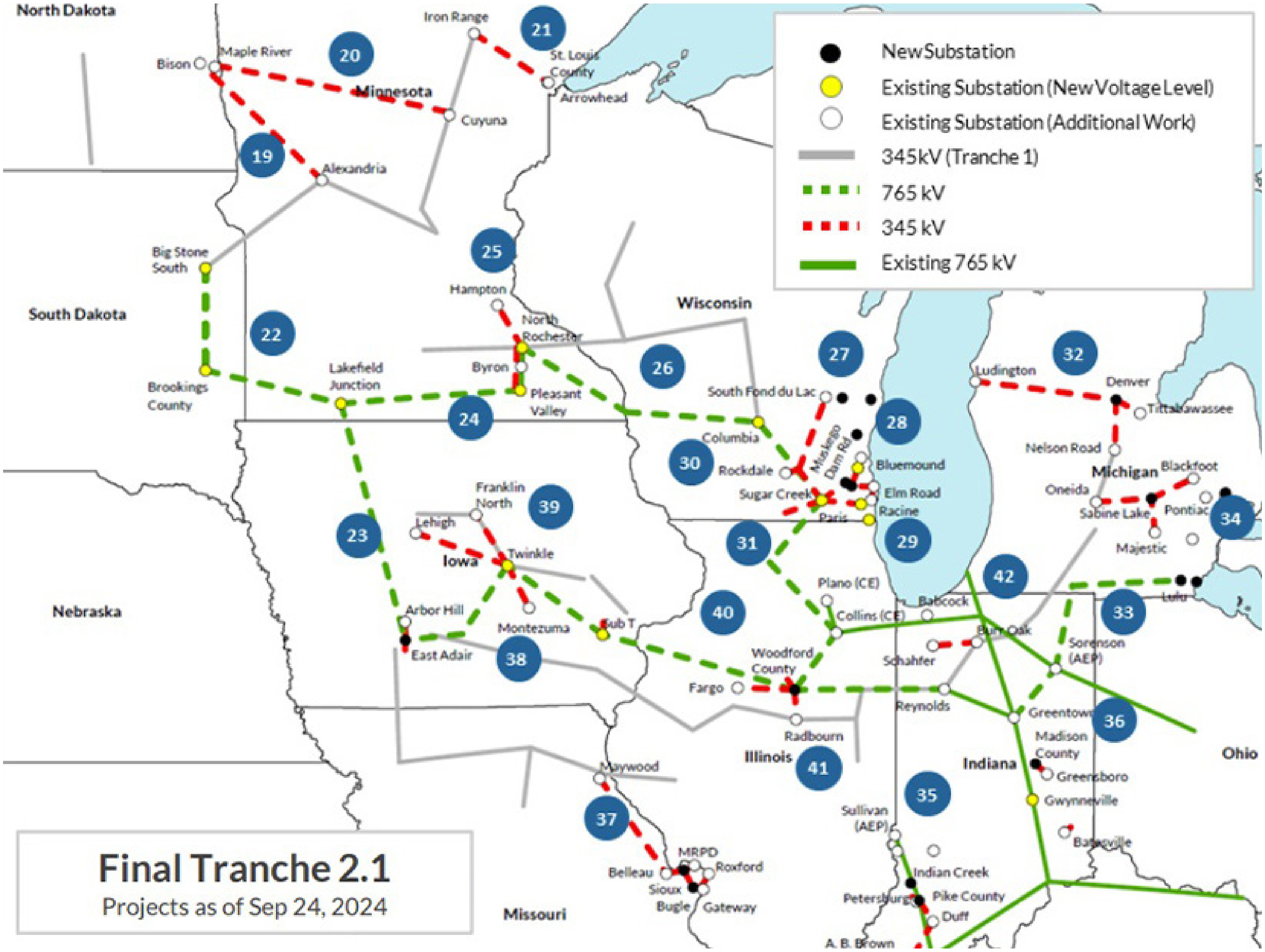
Eight states registered comments supporting the LRTP portfolio.

The Illinois Commerce Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission and Public Service Commission of Wisconsin united to defend the portfolio in a joint filing. They said that of MISO's 15-state jurisdictions and the New Orleans City Council and Manitoba (which makes 17 total jurisdictions), just five states disputed the portfolio, with the three Southern states not set to pay anything for the Midwest projects.

The band of Northern states said the 765-kV projects will help MISO meet a peak load that's expected to grow by 1 to 2% annually through 2044, with anywhere from 23 to 37 GW coming from new data centers. The LRTP portfolio, they said, will "help maintain reliability as load continues to grow, the fleet transitions and weather becomes more extreme."

The four states further disagreed that MISO defied its tariff and said the RTO has "wide latitude" to measure the benefits of long-range transmission.

The Minnesota PUC and Minnesota Department of Commerce called MISO's



MISO's second LRTP portfolio represented by the dashed lines | *MISO* planning process "thorough, transparent and collaborative" and asked FERC to reject the complaint with prejudice.

Indiana Secretary of Energy Suzanne Jaworowski (a former MISO employee) said the state's leadership is "steadfast" in support of the second LRTP, which she said will ensure long-term reliability of the grid while accommodating higher loads.

The Kentucky Public Service Commission agreed, saying, "The buildout of large-scale, high-voltage transmission is part and parcel to the overall value proposition of RTO membership."

Iowa Gov. Kim Reynolds likewise said the portfolio would help the Midwest reliably meet demand and reduce congestion. She wrote that more than 7 GW of proposed generation in the state is on the line if the second LRTP portfolio is interfered with. The Iowa Utilities Commission said the state risks "delayed transmission infrastructure, resource adequacy concerns and potential reliability issues" if the portfolio doesn't proceed.

Consumer advocates, including the citizens utility boards of Illinois, Michigan and Minnesota and the Alliance for Affordable Energy, called the complaint a "full-out assault on MISO's transmission planning process" that fails to specify how the RTO violated its tariff.

"The complainants must not be allowed to come forward months after the fact and allege that MISO's tariff should have included their preferred assumptions," they said.

TOs Unsurprisingly Back LRTP

As expected, MISO transmission owners said the complaint amounted to an "unconvincing attack" on MISO's well established transmission planning process.

They said derailing the projects would jeopardize the Midwest's ability to get essential generation online, including 117 GW of MISO's 300-GW interconnection queue and the 26.5 GW that lined up for the fast-track queue.

"The complaint, if granted, would arrest this potential generation influx and result in unnecessary obstacles to MISO's efforts to reliably, efficiently and cost-effectively address the load-growth projected for the next years. Transmission and generation investment will almost certainly be chilled, compromising MISO's ability to plan the transmission facilities needed to support historic load growth — particularly the load growth due to growing electrification and, crucially, the proliferation of data centers that support budding artificial intelligence technology," the TOs argued. They said if MISO is forced to complete a time-consuming re-evaluation and reassignment of the 24 transmission projects, transmission and generation planning would be "irrevocably" delayed.

The TOs noted that the five states filed the complaint eight months after the MISO Board of Directors voted to approve the portfolio in December 2024 and more than three years since the RTO began the planning process.

DTE Energy likewise said it supported the LRTP's role in modernizing the grid and said the portfolio is "necessary during these unique transitional times in our nation's energy journey."

A joint protest from Clean Wisconsin, the Environmental Defense Fund, Fresh Energy, the Natural Resources Defense Council, Sierra Club, the Solar Energy Industries Association, Sustainable FERC Project and Union of Concerned Scientists said the five states' "true contention is that MISO should have used the modeling assumptions they prefer." They said the complainants were silent as to the fact that MISO doubled-checked the value of the portfolio against its more conservative, first 20-year planning future that contemplates less renewable energy growth and still found a benefit-cost ratio better than 1:1.

Groups including the Data Center Coalition, the Clean Energy Buyers Association and the Electricity Customer Alliance emphasized the need for electricity infrastructure like the LRTP portfolio to win the AI race.

Americans for a Clean Energy Grid pointed to the U.S. Department of Energy's triennial state-of-the-grid report, which found that the Midwest region needs to more than double its regional transmission to meet moderate load growth by 2035.

The Corn Refiners Association and em-Power Rural America also said the lines are "long overdue" in comments.

The nonpartisan think tank Institute for Policy Integrity at the New York University School of Law weighed in that the five states "nitpick[ed] at MISO's numbers." ■

FERC Commissioners Debate 60/40 Capital Structure for Transmission

By Amanda Durish Cook

An apparently routine rate incentive request from a MISO transmission developer who has yet to be assigned a project turned into a debate between FERC commissioners over capital structures in ratemaking (*ER25-2312*).

Midcontinent Grid Solutions (MGS) Iowa — a subsidiary formed by MGS to bid on MISO competitive transmission projects in the state — approached FERC for a 9.98% base return on equity, a 50 basis-point adder for participation in an RTO, regulatory asset treatment to recover its pre-commercial and start-up costs later, and a hypothetical capital structure of 60% equity and 40% debt until it establishes long-term debt.

The company has not yet been awarded any competitive projects in MISO.

FERC's resulting Sept. 8 ruling allowed MGS Iowa the incentives, with the caveat that it include the cost of its actual short-term debt from construction financing in initial debt costs in its formula rate for the period when it has yet to acquire long-term debt. The commission also allowed the company to use the depreciation rates of its affiliate, Transource Wisconsin, until it has its own facilities to glean historical data.

However, the 60/40 equity-to-debt split was a point of contention among commissioners.

Commissioner Judy Chang dissented from the order, arguing that hypothetical capital structures in which equity skews higher can cost ratepayers more and should be evaluated more closely.

"The capital structure used in ratemaking affects the size of the overall revenue requirement by impacting the return on rate base, depreciation and even income tax allowance for the life of the project," Chang wrote. "These components then flow into the resulting rates. The relationship between the assumed capital structure and rates therefore presents a direct impact to ratepayers: the higher the assumed equity component of an applicant's capital structure (without changing the corresponding return on equity), the greater the potential rate impact for customers."

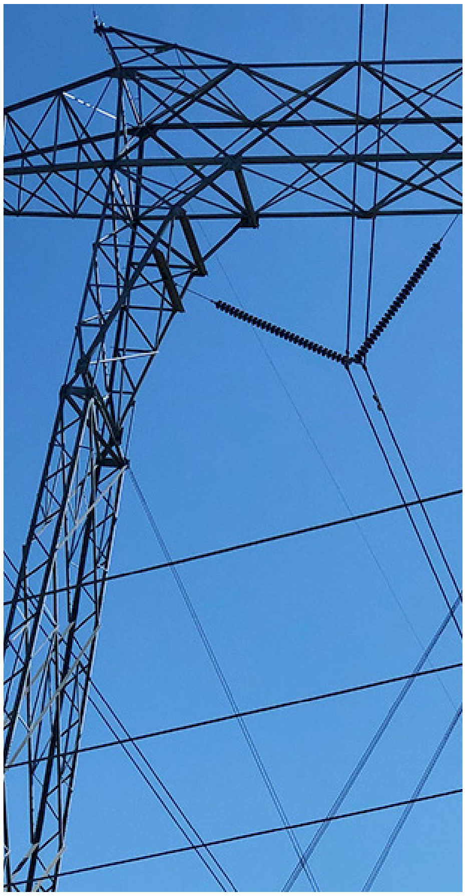
Chang said MGS Iowa did not support its requested capital structure and only cited past commission precedent granting the same figures for other companies. She said FERC's past decisions should not automatically validate MGS Iowa's request.

She also pointed out that while FERC has accepted developers' request for 60% equity with "minimal support," it has also applied greater scrutiny, evidenced by its recent order concerning Valley Link Transmission Maryland.

FERC generally allows up to 60% equity share. However, in May, it rejected Valley Link's proposed 60% equity/40% debt hypothetical capital structure, with the Maryland Office of People's Counsel arguing the proposed ROE was too high and would transfer risk to ratepayers (*EL25-77*).

"The commission should not perpetuate an error simply because it has approved a similar structure in the past for other entities," Chang concluded. "Accordingly, I would reject MGS Iowa's proposed capital structure and establish a paper hearing to determine the appropriate hypothetical capital structure."

Commissioner Lindsay See agreed with Chang that a hypothetical capital structure of 60% equity and 40% debt can "heighten the potential for unjustified rates" and MGS Iowa's argument was "less than ideal."



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"Future applicants might take note that bringing stronger record support for their chosen hypothetical capital structure could make for a smoother path," See wrote in a concurrence to the order.

But See said the temporary capital structure is within the bounds of what FERC has previously approved and would last only until MGS Iowa attains long-term debt financing with a project placed into service. She also said new transmission is associated with "significant financing risks" and noted that no one objected to the capital structure.

"I cannot overlook how the commission has granted similar requests in similar cases very consistently over the better part of a decade. Regulatory certainty drives stable investments, and we need smart investments to build out the grid now more than ever. Taking a sharp turn from the commission's nearly unanimous precedent in this area thus gives me pause," See said. ■

Why This Matters

Commissioner Judy Chang used a rate incentive order from a MISO transmission developer to argue for more scrutiny into the use of hypothetical capital structures of 60% equity and 40% debt.

PJM Stakeholders Endorse Expansion of Provisional Interconnection Service

By Devin Leith-Yessian

The Planning Committee voted to endorse a PJM quick fix *proposal* to expand provisional interconnection service to allow resources that are not fully deliverable to enter service as energy-only resources. The quick fix process allows an *issue charge* and corresponding proposal to be voted on concurrently. (See "1st Read on Expanded Provisional Interconnection Service," *PJM MRC/MC Briefs: Aug. 20, 2025*.)

PJM Director of Interconnection Planning Donnie Bielak said the proposal is intended to allow resources to begin operations while their requisite network upgrades are proceeding, making more energy available to dispatchers going into emergency conditions. As of the Sept. 9 PC meeting, he said more emergency conditions had been declared in 2025 than in the previous decade combined, a trend he said is likely to continue with rising load growth and limited new generation.

Provisional interconnection service allows a planned resource to enter service before the network upgrades assigned to it have been completed only if an interim deliverability study determines it can reach its full output without triggering transmission violations. The proposal would loosen that standard to grant provisional status if a resource can deliver part of its installed capacity, which would be documented in an operational guide to inform dispatchers about how the unit can be operated. It targets provisional service requests for the 2026/27 delivery year; any agreements it awards would need to be renewed by developers with annual interim deliverability studies until the resource enters full service.

Why This Matters

The quick fix proposal focuses on expanding the pathway for developers to apply, and pay, for PJM to study a planned resource for provisional service.

PJM's Donnie Bielak | © *RTO Insider*

The quick fix proposal focuses on expanding the pathway for developers to apply, and pay, for PJM to study a planned resource for provisional service. A separate *issue charge* endorsed by the PC will explore a process for PJM to proactively identify projects that might quality for provisional service without slowing the overall interconnection study process.

The longer-term issue charge *envisions* a 10-month stakeholder effort charging the Interconnection Process Subcommittee with identifying possible changes to the tariff and business manuals. The out-of-scope section includes generation that does not fall under FERC jurisdiction, the requirements for resources to participate in the capacity market, and changes to the interconnection process not pertaining to provisional service.

Bielak said the proposed manual language was amended after the August first read to state that PJM will publish the provisional interconnection service offered to resources to allow market participants to have the same insight on the status of the transmission grid. Additional language was added around how the resources would be dispatched to clarify they won't receive special treatment.

"The existing procedures under these operations will prevail, and these will be treated like any other energy-only resource," Bielak told the PC.

Paul Sotkiewicz, president of E-Cubed Policy Associates, argued PJM should post all requests for provisional service, stating it could inform market participants' hedging strategies. He said the manual language detailing the information about service requests and awards PJM would post should explicitly specify attributes like the output resource owners seek to inject.

Bielak questioned the value that information would provide and said he prefers more generic language to avoid situations where changes to the posting requirements for the overall interconnection process might fall out of sync with the provisional pathway.

Gregory Pakela, manager of regulatory affairs for DTE Energy Trading, said the data Bielak presented shows the bulk of emergency procedures have been initiated during the summer, suggesting reliability risk corresponds to load peaks during heat waves more than PJM's winter-skewed risk modeling would suggest.

"We have to treat models as tools, but the interpretation of those models is almost more of an art," he said. ■

PJM Preparing Alterations to Rejected CIR Transfer Proposal

By Devin Leith-Yessian

PJM is planning to modify and refile a *proposal* to revise how capacity interconnection rights (CIRs) can be transferred from a deactivating resource to a new unit after FERC rejected the tariff language because of language that would have allowed developers to bypass the commercial operation date deadline (*ER25-1128*).

The proposal would create a nine-month process for PJM to conduct a replacement impact study on resources inheriting the CIRs from a deactivating unit and for an interconnection agreement to be offered. It would allow replacement resources to proceed through the expedited study process if minor network upgrades are identified and would not bar any resource class, thus allowing storage to receive CIRs. The revised tariff language will be brought to the Members Committee for endorsement Sept. 25. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

Stakeholders who supported the changes when the Planning Committee first endorsed the language in 2024 argued it would allow gas generators deactivating amid state clean energy policies to be replaced more quickly.

PJM Senior Manager of Interconnection Projects Jason Shoemaker told the PC that FERC signaled support for the overall proposal but identified two areas of concern: exempting resources with long development times from the COD requirement, and a one-time process for developers to request an indefinite delay for their CODs.

In its order rejecting the initial proposal Aug. 8, the commission faulted PJM for allowing developers to request a delay in transferring their CIRs without any time limit, which it said could allow resource owners to effectively withhold CIRs and create barriers to new entry. The commission said that undermines the RTO's stated goal of allowing more resources to come online ahead of a capacity deficiency identified in the 2030 time frame.

"We find that PJM's lack of a maximum time limit for the one-time option for an extension of a replacement generator resource's commercial operation date regardless of cause renders PJM's proposal unjust and unreasonable because it undermines the purpose of the generator replacement process," the commission wrote. "That is, the main purpose of the generator replacement process is to avoid duplicative study costs and operational costs that otherwise would occur when the request to replace an existing generating facility must proceed through the interconnection study queue process, which will in turn avoid delaying the replacement of older resources with more efficient and cost-effective resources."

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The revised language would set the COD requirement at the greater of four years from when the developer submitted an application to construct a replacement resource, or three years from the requested deactivation date of the original resource.

Developers would be able to request an alternative COD during the final agreement negotiation process, but they would have to demonstrate why the requirement should be shifted — akin to the milestone extensions permitted in the generation interconnection agreement process.

After the interconnection study is complete, developers would be able to submit changes to the project to mitigate material adverse impacts and potentially reduce the network upgrades they are assigned. The submission would have to be made within 15 business days of receiving the study results and could only be done once. PJM would retool its analysis with the changes.

The commission also wrote that it saw the logic behind allowing generators with long development timelines some flexibility in their COD requirement but said the language could be ambiguous. While it did not cite that as a rationale for rejecting the proposal, FERC recommended that PJM include more specific language in any refiling.

"We also agree with PJM's goal of offering replacement generation resources that face long lead times a certain degree of flexibility with respect to achieving commercial operation and agree that such resources 'can make a significant contribution to meeting resource adequacy needs, at a time when PJM needs additional resources to maintain reliability,'" the commission wrote.

The COD exemption for resources with "industry-recognized significant construction time frames" was eliminated from the proposal. ■

PJM Operating Committee Briefs

Update on BGE Load Shed Event

PJM's Kevin Hatch *presented* to the Operating Committee an update on the Aug. 11 load-shedding event in Baltimore, which brought 20 MW offline for about half an hour following equipment failures at the Brandon Shores substation. (See *PJM: Baltimore Load Shed Caused by Tx Equipment Failure*.)

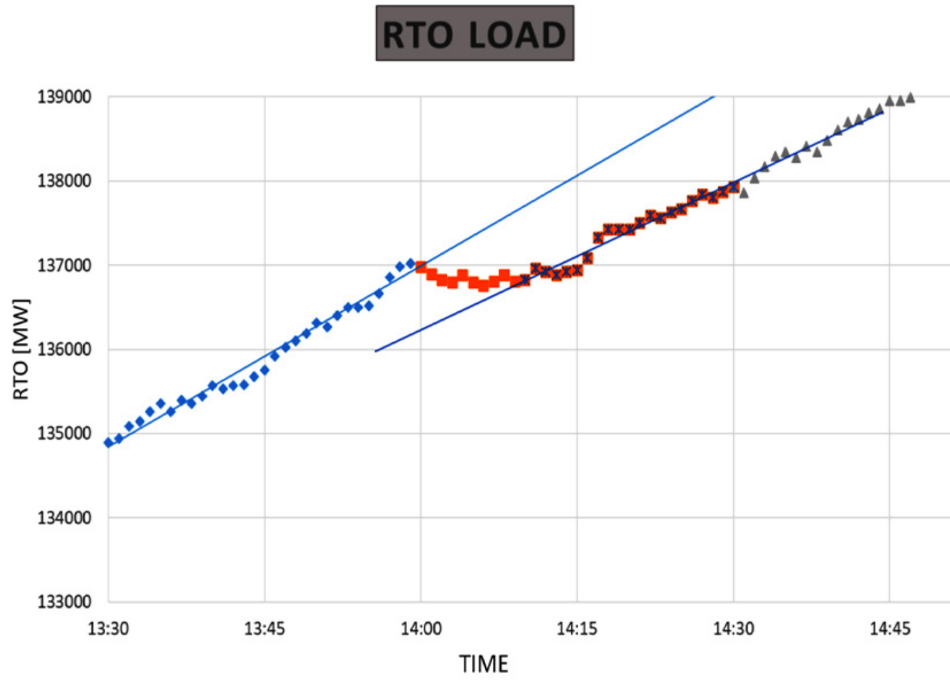
Issues began to mount at the facility at 3:39 a.m. when the 230-kV Brandon Shores-Riverside line tripped, followed by the 230-kV line to Waugh Chapel coming out of service at 5:18 and a 230-kV bus tripping at Brandon Shores. At 5:56 another 230-kV bus tripped and the line to the Wagner substation went offline. At 7:39 a.m. the whole substation went offline after the transmission to Brandon Shores and a second 230-kV line to Waugh Chapel went offline.

PJM implemented several emergency procedures throughout the day, starting with calling 120-minute pre-emergency load management at 8:45 and the 30- and 60-minute products 15 minutes later. Demand response deployments lasted until 8 p.m. As load ramped up toward the afternoon peak, PJM called emergency load management at 2:15 p.m., instituted a 5% voltage reduction at 3 and directed load shed at 3:52.

Hatch said the load shed mitigated an N-5 cascade contingency that put about 1.2 GW at risk when load in the BGE zone exceeded 4.9 GW, which it was forecast to do at 3 p.m. before rising to a peak of about 5.2 GW at 6 p.m. The DR deployments brought load down by about 230 MW, with an additional 60 MW provided by the voltage reduction and 20 MVA from a few combustion turbines that were able to be brought online.

"We took all corrective actions we could to reduce risk to the system," Hatch said.

Some PJM systems showed the emergency procedures as a trigger for a performance assessment interval (PAI), but Hatch said no PAI was initiated because of the localized nature of the event. He said the RTO is exploring changes to its reporting of emergencies to establish that a voltage reduction in a single zone does not automatically start a PAI, which would subject generation owners to Capacity Performance penalties if they underperform their capacity commitments. He said staff are also planning to create a simulation of the event for future training.



PJM presented the results of a voltage reduction test conducted Aug. 14. | *PJM*

Stakeholders Discuss PAI Triggers and Notifications

The committee *discussed* changes to revise the Emergency Procedures (EP) web app's language around PAI triggers to reduce the possibility of users mistakenly believing a PAI is in effect.

Rather than simply specifying that an active PAI trigger is in effect, the app would state a potential trigger has been activated and point users to the *Data Miner* page of PJM's website, which holds the "data of record" on when PAIs are and have been in place. References to PAIs would also be removed from EP email notifications sent to those who have enrolled.

PJM's Chidi Ofoegbu said the aim is to have the changes implemented in October, but no firm date has been selected yet.

Several stakeholders argued the changes do not go far enough and would leave it up to individuals to delve into apps they are unfamiliar with to determine whether generators face penalties in real time.

Voltage-reduction Action Test Results

A test of PJM's voltage-reduction action capability *conducted* on Aug. 14 yielded a little over half the load relief expected and demonstrated a need for additional reactive capability.

The test was expected to bring load down by 1.3%, which amounted to 1,852 MW when it commenced at 2 p.m. A reduction of about 1 GW was seen during the test, around 0.7% of load. Generator reactive capability fell during the duration of the half-hour test by 2,824 MVAR.

Hatch said there was strong communication between PJM and transmission owners throughout the test, and both continue to see value in conducting them twice a year. An additional TO has also communicated to PJM its interest in joining future tests.

Regular tests of voltage-reduction capability were among the recommendations PJM made following December 2022's Winter Storm Elliott, during which the RTO was on the brink of implementing the first reduction action since the 2013/14 polar vortex. The first biennial test was conducted in August 2024. (See "PJM Conducts Voltage-reduction Test," *PJM OC Briefs: Sept. 12, 2024*.)

Preliminary 2026 Capital Project Budget

PJM's Jim Snow *presented* the RTO's preliminary $65 million capital budget for 2026, which includes the purchase of two properties on the same block of its Audubon, Pa., headquarters. The budget is approved by PJM's Board of Managers with input from the membership and Finance Committee.

The funding request is a $15 million increase over the 2025 spending forecast, which itself was an uptick from an average spending of about $40.3 million between 2019 and 2024. The preliminary budget is composed of $21 million for application replacements, $20 million for facilities and technology infrastructure, $19 million for current applications and system reliability, $4 million for interregional coordination, and $1 million for new products and services.

The purchase of 955 and 975 Jefferson Ave. in Audubon falls under facilities and technology infrastructure, which is increasing from $8 million of spending expected in 2025 to $20 million in the proposal. The category also includes replacing obsolete network and server hardware, as well as updating cybersecurity monitoring software.

Snow said the building purchases are likely to occur in the first half of 2026, depending on whether talks with the property owners are successful.

Application spending, which is flat from 2025, includes a new short-term load forecast model, replacing "critical" out-of-support software used in weekly and monthly settlements and continuation of the multiyear Next Generation Markets Systems project to upgrade the market clearing engine.

Snow said much of the current applications and system reliability spending is for multiyear projects, such as overhauling the Dispatcher Application and Reporting Tool.

Staff deferred requesting $3.8 million for optimizing the modeling of combined cycle generators in the budget, as well as $1.3 million for improvements to the Energy Management System and an additional $1.3 million for technology upgrades.

August Operating Metrics

PJM *experienced* an average hourly load forecast error of 1.37% in August and an average peak forecast error of 1.80%, according to an RTO presentation.

There were four days where over-forecasting exceeded the RTO's 3% peak load error benchmark on Aug. 1, 6, 20 and 21. The first three were attributed to actual temperatures coming in lower than expected, while the 6.92% peak error on Aug. 21 was from "excessive temperature error" across several zones.

The month saw three spin events, one Energy Emergency Alert level 2 event, three pre-emergency load management reduction actions, one emergency load management reduction action, two high system voltage actions, two hot weather alerts and 25 post-contingency load relief warnings. Five shortage cases were approved, three falling on Aug. 14 and two the following day because of ramping interchange, solar output falling faster in the evening than the load ramp and combustion turbines not coming online as scheduled.

The three spin events each fell below the 10-minute duration PJM uses to determine when it may back down a 30% adder on the synchronized and primary reserve requirement. Performance must be above 75% for the adder to be reduced by 10% and a larger reduction is possible if performance is higher. (See *PJM OC Briefs: March 6, 2025*.)

An Aug. 6 spin event had a 1,679-MW generation assignment, 69% of which responded, and 83 MW DR assignment, with a 42% response.

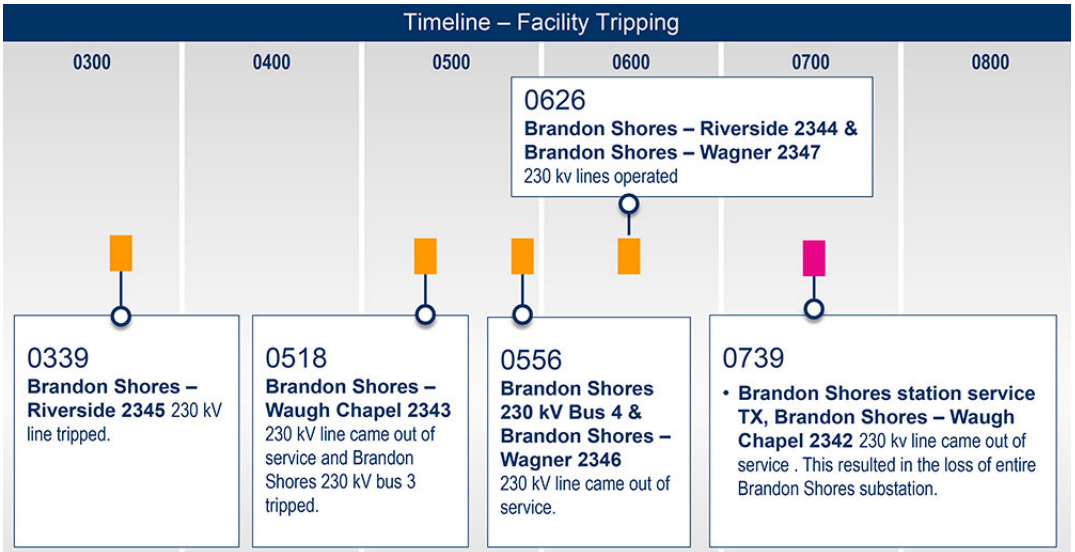
An Aug. 14 event had 2,855 MW of generation assigned, with 51% responding, and 538 MW of DR, 74% of which responded. An event the next day had 3,245 MW of generation assigned, 64% responding, and 454 MW of DR assigned, with 82% responding.

Cybersecurity Report

Delivering the monthly security report, PJM Director of Enterprise Information Security Jim Gluck highlighted a ransomware attack that used Anthropic's Claude artificial intelligence software to target 17 organizations, including identifying network weaknesses, writing code used to bypass intrusion detection measures and obtaining individual credentials. Anthropic has *published* an article detailing how the attack was conducted and the guardrails it is developing to limit future potential, but Gluck said the use of AI continues to be a game of cat and mouse.

Gluck also *recommended* that stakeholders participate in a study researchers at the University of Pittsburgh are conducting to understand the barriers to additional cybersecurity spending, with the goal of creating a set of recommendations and a policy guide. ■

— Devin Leith-Yessian



A PJM graphic shows the timeline of issues causing the Baltimore substation to go offline Aug. 11, leading to a 20-MW load shed. | *PJM*

PJM TEAC Briefs

Update on New Jersey and Maryland SAA

PJM and the New Jersey Board of Public Utilities are in discussions on how the transmission and interconnection facilities planned for the state's offshore wind aspirations can be put on ice in the wake of all the generation developers pulling out of their projects. (See *N.J. Puts on Hold Remaining Pieces of $1.07B OSW Transmission Project*.)

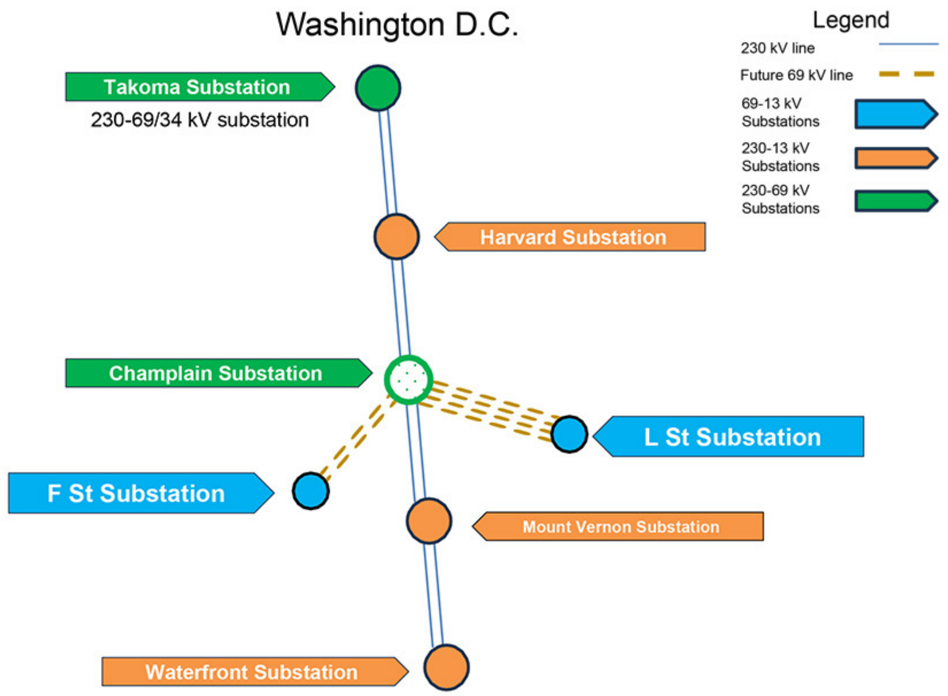
The RTO has *responded* to a BPU request to pause transmission planned under FERC Order 1000's State Agreement Approach (SAA) by asking for clarification on what a "delay" means and to clarify that PJM requires amendments to the SAA and designated entity agreements for those tasked with developing the transmission. That includes new in-service dates for the OSW projects and a solicitation schedule for finding new developers for the generation.

PJM Senior Manager of Policy Initiatives Susan McGill told the Transmission Expansion Advisory Committee that the RTO's request is not adversarial but meant to ensure that the BPU's request can be fulfilled to the greatest degree possible without compromising reliability. She added that staff have also reached out to all entities involved in the SAA projects.

Planning staff have sorted through the SAA transmission to identify radial expansions with no impact on reliability, which can likely be deferred without issue, and multi-driver projects, which support both OSW interconnection and larger reliability needs or the interconnection of unrelated generation. Multi-driver projects may have to proceed regardless of the BPU's request.

PJM is also *processing* a request from the Maryland Public Service Commission to use the SAA to support its goal of installing 8,500 MW of OSW by 2031. The two are working to draft an approach on how to proceed with the SAA, which would be PJM's second, with the goal of the RTO completing its analysis and opening a competitive window for transmission projects in 2026.

The RTO has conducted an initial study on possible interconnection points based on the 2024 Regional Transmission Expansion Plan (RTEP) case, the results of which led the state to support a plan with five injection points. The scenario identified would begin with injecting 2 GW at Delmarva Power's Indian River substation in 2028, followed by 3,500 MW in 2030 split equally between the utility's Cool Springs, Piney Grove and Nelson sites. The last 2 GW would come online at PEPCO's Calvert Cliffs substation in 2031.



Exelon presented PJM stakeholders with a $590 million project to upgrade and reactivate the Champlain substation in D.C. | *Exelon*

McGill said PJM staff and transmission developers participating in the New Jersey SAA competitive windows found having two separate windows was disruptive to the RTEP process, so the intention going into the Maryland SAA is to have one solicitation and window.

PJM Presents RTEP Update

PJM is evaluating 134 *proposals* submitted, of which 57 are classified as greenfield and 77 as upgrades, in the 2025 RTEP Window 1 competitive window, which closed Aug. 18.

The projects also include grid-enhancing technologies, with five involving HVDC lines and five advanced conductor proposals.

PJM's Matthew Wharton said there's a need for solutions providing west-to-east transfer capability, with most of the corresponding submissions focusing on expanding the 765-kV backbone. Many of the 500-kV proposals focus on improving north-south flows within the eastern side of the RTO. The proposals are skewed toward higher-voltage solutions, both in number and cost, with 56 involving 500-kV projects and 29 at the 765-kV level.

Wharton said the projects have been reviewed for deficiencies, and PJM is waiting for responses from the submitters. Staff plan to review the proposals and pursue a first read on noncompetitive projects during the TEAC's October meeting, with recommendations on competitive projects to be held throughout the winter. The RTO's goal is to receive Board of Managers approval for a package in the first quarter of 2026.

Generation Deactivation Update

Vistra has notified PJM that it intends to deactivate two coal-fired units at its Kincaid generator with an installed capacity of 1,112 MW. The deactivation *notice* states that the company is seeking to bring the units offline by Nov. 30, 2027, to comply with the EPA's coal combustion residual rule.

Milepost Power has also submitted a deactivation notification for its 31-MW gas-fired Forked River Unit 2 because of "its inability to meet New Jersey air permit requirements." The company initially requested to bring the unit, located in the JCPL zone, offline on June 1, 2026, but shifted that out by one year.

PJM's Michael Herman said staff have completed a reliability analysis on requests to deactivate Warren Evergreen CT 1 and Cooper Unit 1, together amounting to 121 MW, and did not identify any violations.

Supplemental Projects

AES Ohio *presented* a $74.1 million transmission project to serve a customer near Marysville, Ohio, seeking to ramp its load to 135 MW by July 2028; the customer plans to initially come online in February 2027 with 22 MW.

The project would construct a new 138-kV substation in a breaker-and-a-half (BAAH) configuration cutting into the 138-kV Millcreek-AD2-163 line and expand the Darby substation with a 138-kV BAAH yard. The new substation would be connected to Darby with a 5-mile 138-kV line. The project is in the conceptual phase with an in-service date in April 2028.

Duquesne Light Co. *presented* a $46.3 million project to fulfill a new service request seeking to bring 250 MW to Monroeville, Pa., with a projected in-service date in January 2029. It would construct a new 138-kV substation, named McGinley, in a BAAH configuration with 12 breakers and a 50-MVAR capacitor bank. It would be looped into the 138-kV Cheswick-Yukon and Springdale-Huntington lines.

PPL *presented* a $187 million project to serve a customer seeking to bring 300 MW to Gouldsboro, Pa., ramping to 1.5 GW in 2030. The project would construct a 230-kV BAAH substation, named Big Bass, along the 230-kV Pocono-Acahela line to connect to two 230/34-kV substations to serve the customer. The 230-kV corridor between Paupack-Pocono-Acahela would be upgraded with an additional circuit, which would also extend from Acahela to Jenkins and from Paupack to Callender Gap and Lackawanna. Several of the substations along the corridor would be upgraded with new bays and breakers to accommodate the additional circuit.

PPL also presented a $95 million project to serve a customer seeking 230-kV service in Hazleton, Pa., for a load coming into service in 2027 with 350 MW to ramp to 1 GW in 2030. The project would reconductor the 10-mile 230-kV Susquehanna-Tomhicken line and construct a new 230-kV line from Harwood, through Slykerville and to Tresckow. The new corridor would initially be single-circuit, with the intention of upgrading it to double-circuit. The Harwood, Slykerville, Tresckow and Nescopeck substations would be upgraded with 230-kV bays, and three 230-kV line terminals would be installed at Tresckow for the lead lines to the customer substation. A new 500/230-kV transformer would be installed at the Susquehanna 500-kV yard, and a 3.75-mile 230-kV line would be constructed from the 500-kV yard to Nescopeck, initially as single-circuit but to be upgraded to double.

Exelon *presented* a $590 million project to address issues aging and faulty equipment in the D.C. area by replacing the deactivated Champlain substation with a 230/69-kV station with gas-insulated, BAAH buses for both voltages and three 230/69-kV transformers. The Takoma substation would be upgraded with two 500-MVA phase-shifting transformers to control power flows and prevent overloads in N-1-1 contingencies. The work would create a new 69-kV source to the D.C. core and allow the L Street substation to retire. It would also enable the retiring of 11 oil-filled cables under the Potomac River that have seen operational issues.

Exelon *presented* a $84.8 million project to serve a customer seeking to bring 225 MW to the Hoffman Estates region of the ComEd zone in September 2028, with the expectation to ramp to 612 MW in 2031. A 345-kV substation, named Beverly Road, would be constructed with two 150-MVAR capacitor banks and a double ring bus to be expanded to a BAAH. The facility would cut into the 345-kV Libertyville-Tollway and Silver Lake-Wayne lines with two half-mile, double-circuit lines. The project is in the conceptual phase with a projected in-service date of Sept. 1, 2028.

Dominion Energy *presented* a $56.5 million project to construct a 230-kV substation, named Azalea Lane, along the Brambleton-Evergreen Mills line. The facility would serve load growth in Loudoun County, Va., with a requested in-service date of Dec. 31, 2029. The substation would be configured in a four-breaker ring.

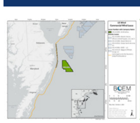
The utility also presented a $20 million project to resolve a 300-MW load drop violation identified in the 2025 Do No Harm analysis, which would cause the Racefield and Reed Farm substations to be offline. The solution involves upgrading Azalea Lane and Reed Farm to six breakers and constructing a double-circuit 230-kV line between the two. The project is in the conceptual phase with a projected in-service date of Dec. 31, 2029.

Rappahannock Electric Cooperative has requested a new substation, to be named Matta, in Caroline County, Va., to serve a data center coming online on Dec. 1, 2026, and expected to ramp to 300 MW by 2031. The project is expected to cost $25.5 million, including $18.1 million for the substation and $7.4 million to cut into the Ladysmith CT-Kraken line.

Public Service Electric and Gas *presented* an $85 million project to provide relief for the Mount Laurel substation in New Jersey, which has a projected contingency overload of 115.3%. The solution would construct a 230/13-kV substation along the 230-kV Cox's Corner-Burlington line and feature two 230/13-kV transformers. The project is in the conceptual phase with a possible in-service date in May 2031. ■

— Devin Leith-Yessian

National/Federal news from our other channels



BOEM Seeks to Vacate Maryland Offshore Wind Approval

NetZero Insider

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

PJM MIC Endorses 2 Quadrennial Review Proposals

By Devin Leith-Yessian

Skyler Marzewski, PJM | © *RTO Insider*

The PJM Market Implementation Committee voted to endorse two packages of revisions to key parameters of the capacity market out of six offered by PJM and stakeholders that resulted from the Quadrennial Review. (See *PJM Stakeholders Discuss Quadrennial Review Proposals*.)

The Quadrennial Review resets the variable resource requirement (VRR) curve, which defines the amount of capacity the market procures and at what cost. The review also updates the reference resource technology class, currently a combustion turbine; the cost of new entry (CONE) for the reference resource in various regions of PJM; and the energy and ancillary services (EAS) offset, which estimates revenues outside the capacity market to net against CONE.

A proposal from LS Power received the greatest degree of support: 55.6% for both endorsement and preference over the status quo. It seeks to maintain the core design of the VRR curve while updating it for the changing economics of a CT. It adopts PJM's initial recommendation of shifting the reference resource to a four-hour battery electric storage system (BESS) in the ComEd zone, which supporters have argued reflects the shorter expected lifespan of gas generation under the Illinois Climate and Equitable Jobs Act's (CEJA) emissions requirements.

The package tinkers with the heat rate, variable operating and maintenance costs, and net summer ICAP attributes for the General Electric 7HA.03 turbine and added wet compression capability. The changes would result in the gross CONE decreasing by about 8% to between $613 and $630/MW-day of installed capacity, depending on the CONE area.

A joint *proposal* from PJM and Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow was also endorsed, though it did not receive support over the status quo design. It included a CT reference resource for all zones, with the gross CONE between $592 and $679/MW-day, lower than the LS Power proposals.

PJM's Skyler Marzewski said the rationale for using a gas generator in ComEd, rather than BESS, is that the falling effective load-carrying capability (ELCC) accreditation for storage is so sharp in the long-term estimates out to 2030 that a gas capacity resource remains more economic even with the truncated asset life. The proposal includes an adjustment to the asset life factor to reflect CEJA.

Staff opted to adopt elements of Barrow's VRR curve to address uncertainty around CONE and EAS estimates. Rather than basing the price on multiples of gross and net CONE, the joint package sets the maximum price as the greater of 115% of gross CONE minus 75% of net CONE or 20% of gross CONE, which Marzewski said would avoid the maximum price collapsing to zero. The middle point would be defined as half of the maximum and the floor would be zero. The maximum would represent 99% of the reliability requirement; the middle would be 101.5%; and the floor 106%.

Like other proposals, the package would calculate the net EAS offset using forward-looking hourly energy and gas prices, but it would take the 67th percentile of calculated zonal values, which Marzewski said is meant to reflect that developers will seek to optimize their revenues when selecting where to site a resource.

The MIC's votes were only indicative of stakeholder support. The two endorsed packages will be voted on along with the other four by the Markets and Reliability Committee and Members Committee at their meetings Sept. 25. The Board of Managers will ultimately decide on what revisions to propose.

Other Packages

A variant of the joint PJM and Barrow proposal swapped the CT for a combined cycle reference resource, resulting in a higher gross CONE, between $752 and $860/MW-day. The package did not receive endorsement, with a vote of 26.6% and 27.1% support over the status quo.

Marzewski said PJM prefers a CC reference resource, but its modeling of the two VRR curves in its proposals found there is not a huge difference in the results between a CT and CC under this design. A stakeholder process would be needed shortly after selecting a CC reference to mitigate the risk of the net CONE falling and causing a zero Capacity Performance penalty rate. PJM had sought to implement a CC reference resource in the fifth Quadrennial Review, but it reverted to a CT for the 2026/27 Base Residual Auction and the next auction because of concerns that the higher EAS revenues could lead to depressed capacity prices and knock-on effects on other parameters derived from net CONE, such as the CP penalty rate. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

LS Power proposed a second package with the same CT and BESS reference resource characteristics as its initial package while reversing the VRR curve to the shape used in the *third review*, in place between 2014 and 2018, with adjustments to account for the ELCC accreditation and risk modeling paradigm. The maximum price would be set at the greater of gross CONE or 1.5 times net CONE divided by the accredited unforced capacity factor; the middle point would be 75% of net CONE; and the minimum would be zero. It received 43.9% support in the endorsement vote with the same for the status quo.

A standalone proposal from Barrow used a BESS reference resource in ComEd and a CC in all other zones and included a VRR curve similar to the joint proposal without the 20% gross CONE floor to the maximum price. It also did not include wet compression in the modeling of the CC reference resource. It received 21.3% support for endorsement and the same over the status quo.

The Independent Market Monitor's *proposal* used a CT, without wet compression, for all zones with the gross CONE between $474 and $561/MW-day and a 20-year levelization except in ComEd, where it would be 15 years to reflect CEJA. The maximum price on the VRR curve would be the lower of gross CONE or 150% of net CONE; the midpoint would be half of the maximum; and the minimum would be zero. The quantities would be 99% of the reliability requirement for the maximum, 101.5% for the midpoint and 104.5% for the floor. It received 22.4% support for endorsement and over the status quo. ■

SPP Clears GI Queue Backlog, Ready for New Process

By Tom Kleckner

SPP says it has cleared its backlog of generator interconnection requests that dates back to 2018, paving the way for a transition to its "first-in-the-country" Consolidated Planning Process.

The grid operator said in a *news release* that the six study clusters through 2023 have all reached the restudy phase. Each request in the clusters has completed the two-part study phase and is either signing GI agreements, moving into GIA negotiations or undergoing a restudy, an SPP spokesperson told *RTO Insider*.

"SPP's interconnection customers deserve an efficient study process to enable their proposed generator projects," Jennifer Swierczek, the RTO's manager of generation interconnection policy and study, said in a statement.

SPP said efficient interconnection studies are critical and give developers and utilities the cost certainty and regulatory approvals needed when energy demand is rising.

Staff have completed 24 cluster studies since 2022, analyzing 340 GW of generation — six times SPP's peak load — and evaluating 1,652 projects through its definitive interconnection system impact studies (DISIS).

Why This Matters

By clearing its backlog of generator interconnection requests, SPP said it is able to more efficiently and quickly lead to GI agreements. The current sequential planning and GI studies have led to an average of six-year wait times before resources go into service.

The work has resulted in 190 signed GIAs for more than 30 GW of generation. Another 20 GW of additional generation is expected to execute GIAs in the next 12 months, the RTO said.

According to SPP's *GI queue dashboard*, 191 active requests from the backlog remain in the GI queue. The 2024 study cluster, which has not yet gone through DISIS, includes 345 requests for about 90 GW of capacity.

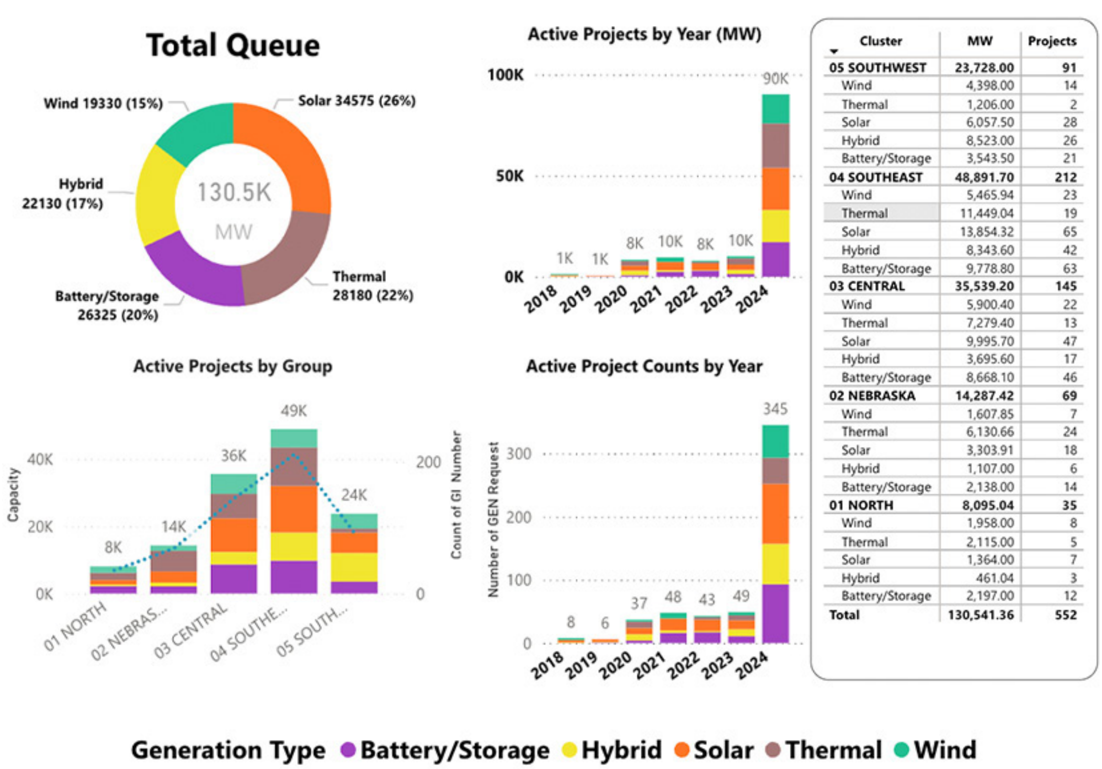
SPP began tackling the backlog in 2022 with the 2018 cluster. The queue contained 1,139 active requests for 221 GW of capacity at the time; it now has 552 active requests for 130.5 GW of capacity. (See "SPP Modifies GI Backlog Process," *SPP Markets & Operations Policy Committee Briefs: Oct. 15-16, 2024*.)

The grid operator's board, state regulators and members approved the CPP in July and August. It replaces the current sequential planning and GI studies that have led to an average of six-year wait times before resources go into service.

The new process includes a long-term 20-year study and an annual 10-year assessment, aligning system modeling, planning assumptions and cost allocation across load and generation needs. The CPP-10 includes a GI capability study, a GI decision point and a regional transmission assessment that recommends projects for construction. The CPP-20 establishes a 20-year regional vision. (See *SPP Celebrates Novel Consolidated Planning Process*.)

Staff will be able to use the process once it has FERC approval, significantly accelerating the addition of new generating resources to the grid. SPP has said it plans to file the tariff change with the commission by October and will request an effective date of March 1, 2026.

Full implementation will begin in 2027, and the first CPP portfolios are expected to be delivered in 2028. Transitional work will bridge the gap between the CPP framework and the current study process for the 2026 and 2027 assessments. ■



Cluster	MW	Projects
05 SOUTHWEST	**23,728.00**	**91**
Wind	4,398.00	14
Thermal	1,206.00	2
Solar	6,057.50	28
Hybrid	8,523.00	26
Battery/Storage	3,543.50	21
04 SOUTHEAST	**48,891.70**	**212**
Wind	5,465.94	23
Thermal	11,449.04	19
Solar	13,854.32	65
Hybrid	8,343.60	42
Battery/Storage	9,778.80	63
03 CENTRAL	**35,539.20**	**145**
Wind	5,900.40	22
Thermal	7,279.40	13
Solar	9,995.70	47
Hybrid	3,695.60	17
Battery/Storage	8,668.10	46
02 NEBRASKA	**14,287.42**	**69**
Wind	1,607.85	7
Thermal	6,130.66	24
Solar	3,303.91	18
Hybrid	1,107.00	6
Battery/Storage	2,138.00	14
01 NORTH	**8,095.04**	**35**
Wind	1,958.00	8
Thermal	2,115.00	5
Solar	1,364.00	7
Hybrid	461.04	3
Battery/Storage	2,197.00	12
Total	**130,541.36**	**552**

SPP's current generator-interconnection queue shows the results of the backlog-clearing effort. | *SPP*

Company Briefs

NextDecade Greenlights Train 4 at Rio Grande LNG Export Project

U.S. liquefied natural gas producer NextDecade last week said it has reached a final investment decision for the fourth liquefaction plant, known as a train, of its Rio Grande export project in Texas.

Train 4 has an expected LNG production capacity of nearly 6 million tons per annum (mtpa), bringing the total expected capacity under construction at the facility to about 24 mtpa.

Construction is expected to be completed in 2030.

More: *Reuters*

Mars, Enel Agree to Solar PPA

Enel North America and Mars, a pet care, snacking and food company, last week announced a power purchase agreement involving the full output of three solar plants in Texas.

The deals represent Enel's largest corporate PPA transaction worldwide, combining for a total of 851 MW.

More: *Power Magazine*

Rivian Lays off 200 Additional Workers Ahead of R2 Rollout

Electric vehicle automaker Rivian last week announced it will lay off 200 more employees.

The company said the cuts are part of an overall plan to streamline production ahead of its release of a smaller SUV next year. That team includes sales and service employees, who are eligible for rehire to other positions within the company.

More: *San Gabriel Valley Tribune*

Federal Briefs

DOE Announces $134M to Advance Fusion Leadership

The Department of Energy last week announced $134 million in funding for two programs designed to secure U.S. leadership in emerging fusion technologies and innovation.

The department announced $128 million for the Fusion Innovative Research Engine collaboratives and $6.1 million for the Innovation Network for Fusion Energy program.

The investments are part of DOE's broader mission to ensure the technologies that define the future of fusion power are developed here in the U.S.

More: *DOE*

BLM Geothermal Lease Sales in Idaho Net over $4M

The Bureau of Land Management last week announced it accepted winning bids on nine parcels in Idaho totaling nearly 24,355 acres for $4.4 million in a geothermal lease sale.

The combined bonus bids, rentals and subsequent royalties from the leases will be distributed among the U.S. Treasury, Idaho, and Elmore, Washington and Bonneville counties, where the leases are located.

More: *BLM.gov*

State Briefs

CALIFORNIA

Arrow Line Welcomes 1st U.S. Hydrogen-powered Train

The nation's first hydrogen-powered passenger train began operations Sept. 13 on Metrolink's Arrow line between Redlands and San Bernardino.

The train uses hydrogen fuel cell and battery electric technology to move itself and power onboard electrical systems. Water vapor is the only emission from the propulsion system.

More: *The Press-Enterprise*

DELAWARE

PSC: Data Centers Will Pay Higher Rate for Electricity

The Public Service Commission has voted to stop "large-load consumers" such as data centers from connecting to the grid until the commission can create a new electricity rate for them.

PSC Attorney Kate Workman cited a Synapse Energy Economics study, commissioned by the Sierra Club, which found that data centers will cause residential bills to increase by 10% in the near term and 4% in the long term.

Delmarva Power will figure out what the new rate will be, and the PSC will decide whether to approve it.

More: *Spotlight Delaware*

GEORGIA

Georgia Power Receives PSC Approval for 5 Solar Facilities

Georgia Power last week received Public Service Commission approval to certify five new utility-scale solar site power purchase agreements to supply the company's Clean and Renewable Energy Subscription (CARES) 2023 program.

The new facilities, consisting of 1,068

MW, will be built and maintained by third-party companies that successfully bid projects in the CARES 2023 Request for Proposal.

More: *Grice Connect*

KANSAS

Proposed Utility Plan Seeks to Fairly Allocate Costs from Big Users

Next month, the Corporation Commission will consider a unanimous settlement agreement created after multiple consumer, nonprofit and private interest parties worked to reach agreement on a large load service rate plan and utility tariff.

The unanimous agreement designs a rate structure for large-load customers, defined in the agreement as those that reach a peak load of 75 MW monthly. Large-load users will sign a 17-year contract outlining their maximum load projections. Even if the company reduces its electrical demand to 50 or 75% of its projection, the company will be required to pay 80% of that projection.

The commission will hold a one-day hearing Oct. 8.

More: *Kansas Reflector*

LOUISIANA

DENR Approves 1st Carbon Capture Storage Well

The state Department of Energy and Natural Resources last week authorized construction of its first ever carbon capture and storage well.

The order comes more than a year and a half after the EPA granted the DENR authority to permit wells for the technology, which injects high-pressure carbon dioxide in a near-liquid state deep underground. The permit would allow Hackberry Carbon Sequestration to build a well that could pump up to 2 million metric tons of carbon dioxide annually for 20 years under Black Lake southwest of Lake Charles.

More: *The Advocate*

MICHIGAN

Report: Utility Customers Suffered Nation's Longest Outages in 2023

State utility customers dealt with longer power outages in 2023 than any other state, and the utilities rank near the bottom of the list nationwide on other reliability metrics, according to a Citizens Utility Board of Michigan report based on U.S. Energy Information Administration data.

Last week, the Public Service Commission ordered investor-owned utilities to credit an additional $2 to customers experiencing lengthy or repeated outages, increasing the automatic bill credit to $42.

The PSC painted a different picture of the findings, saying they show an improvement in reliability "when controlling for weather." The PSC said the report shows a 23% reduction in power outages between 2019 and 2023 when "major event days" are excluded.

More: *Planet Detroit*

MISSISSIPPI

PSC Triggers Daily Fines Against Holly Springs

The Public Service Commission last week voted unanimously to initiate daily fines of up to $12,500 against the city of Holly Springs as long as it violates state law regarding providing utility services.

The vote comes after a PSC hearing two weeks ago about Holly Springs' long troubled power provider. At the hearing, the commission made two decisions: to declare the city had "failed to provide reasonably adequate service," violating state law, and to petition a chancery judge to place the utility into a receivership.

More: *Mississippi Today*

MISSOURI

Staff Recommend PSC Reject Ameren Data Center Plan

Ameren's proposal for new large data center rates could raise electric bills by an estimated $22 million/year, according to filings from Public Service Commission staff.

Staff said the commission should reject Ameren's proposal in a rebuttal document filed Sept. 5. Ameren's plan will not protect customers' rates "from reflecting unjust and unreasonable costs," staff wrote. Staff stated that before a rate case could recognize a new data center customer, all expenses related to the customer would flow to existing customers, while all revenue from the data center would flow to shareholders.

The PSC will hold a hearing in November while reply briefs are due in early January. A final decision should come after that.

More: *St. Louis Public Radio*

OHIO

PUC Turns down Appeal, OKs AEP's Data Center Billing Plan

The Public Utilities Commission last week approved AEP's plan to charge data centers at a different rate.

PUCO's latest decision set aside an appeal brought by tech interests like Amazon, Google, Meta and Microsoft, as well as the Ohio Manufacturers Association. However, the companies can still appeal to the state supreme court.

AEP's initial proposal applied to data centers using more than 25 MW a month.

More: *Ohio Capital Journal*

OREGON

State Challenges EPA over Terminated Solar Program

The Oregon department of energy last week filed a challenge with EPA, which terminated the grant for the Solar for All program even though it had already been awarded under a legally binding agreement.

The state requested that EPA rescind the cancellation and release the $88.6 million as promised.

EPA awarded the money to the state in July 2024 — part of the $7 billion in Solar for All awards nationwide. The funding was established under the Inflation Reduction Act. But the EPA last month informed Oregon and other states their contracts had been ended.

EPA has 15 days to acknowledge the state's dispute letter and 180 days to decide.

More: *The Oregonian*