ISSN 2377-8016 : Volume 2025/Issue 23 ▪ June 10, 2025

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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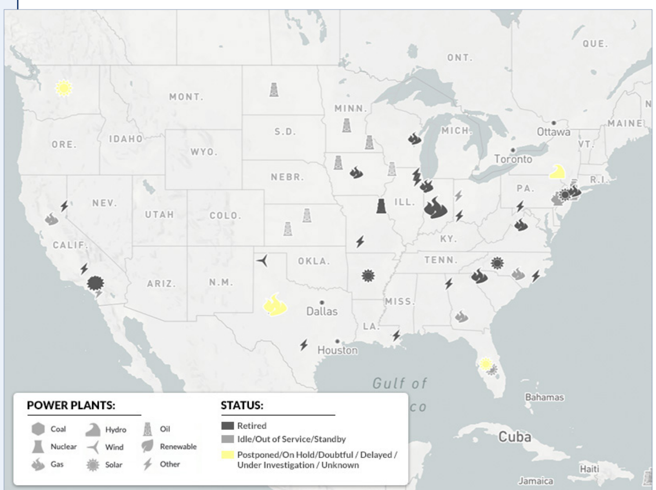
FERC/FEDERAL MISO

FERC Dives into Thorny Resource Adequacy Issues at Tech Conference



Yes Energy

The technical conference comes as states and stakeholders consider alternative capacity markets, as well as alternatives to them altogether.

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PJM

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CAISO/WEST

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FERC Dives into Thorny Resource Adequacy Issues at Tech Conference

By James Downing

For most organized markets across most of their history, resource adequacy was relatively easy to handle, with supply long and demand growing slowly.

That has changed rapidly in just the past few years, with a spike in demand growth led by new data centers. FERC spent June 4-5 looking into the issue across the markets it regulates.

FERC Chair Mark Christie has been talking about a reliability crisis for years, as dispatchable generation has retired with replacements that at best do not offer the same characteristics.

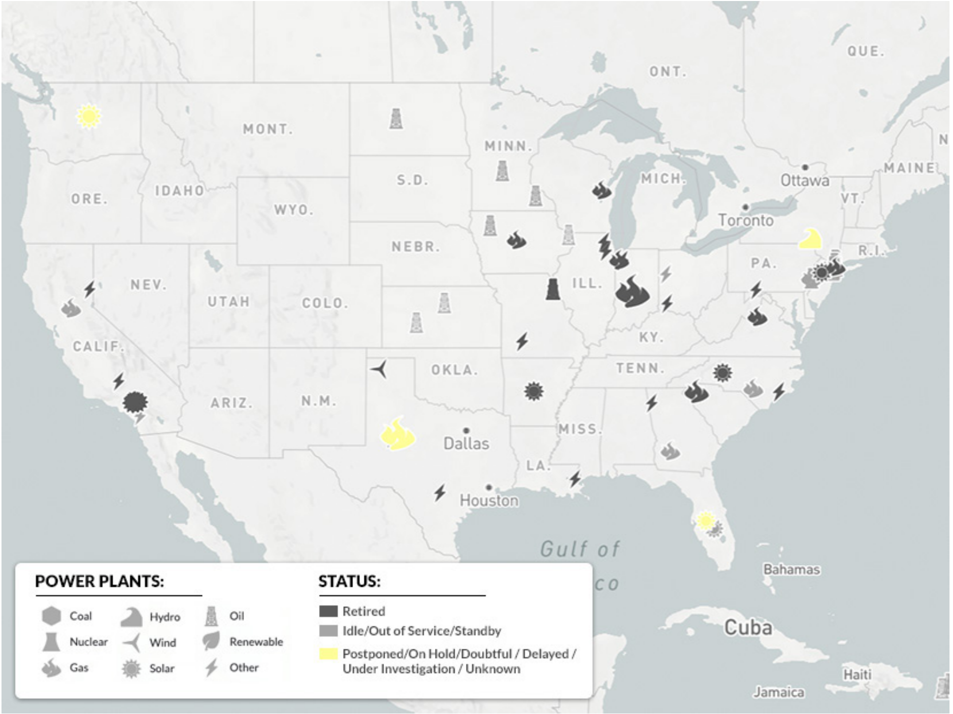
"So now the crisis is really right on our doorstep," Christie said. "But let's not forget, while this conference is about the impending crisis of reliability from resource shortfalls, it really has another crisis connected to it, and that is the crisis of rising consumer power bills, because consumers have to pay for capacity, as we all know. And I know that in at least two states in PJM — Maryland and New Jersey — this very week consumers are seeing big jumps in their power bills because of rising capacity costs."

The technical conference, along with pre-filed comments and another round after the conference, will build a record that FERC could use in future proceedings on the issues, he said.

The industry is facing a lot of uncertainty, including extreme weather, supply chain constraints, rising costs for equipment and how much it can really count on demand forecasts, Commissioner Judy Chang said.

Why This Matters

The technical conference comes as states and stakeholders consider alternative capacity markets, as well as alternatives to them altogether.



A map from Yes Energy showing generation retirements, the rate of which was a key factor prompting FERC's technical conference on resource adequacy this week. | *Yes Energy*

"The compounded complexities around the regulatory and commercial structures deployed in various regions across the country make all of our jobs difficult, and that's why we're having this conversation today, to add to the record, but also to add an opportunity to discuss these questions," she added.

NERC has been monitoring resource adequacy for decades, and, outside a few regions, it was mostly boring until 2018, CEO Jim Robb said.

"For the first time, in 2018, our long-term resource adequacy assessment showed a material expectation of long-term unserved energy, and 18 months later, that expectation, unfortunately, was realized with a significant load-shed event in California in August of 2020," Robb said. "And since then, our analyses have shown growing risk of unserved energy across the continent."

The theory around resource adequacy in wholesale markets was simple, with trading in spot markets producing price signals that would lead to bilateral deals that can support new entry of generation, ISO-NE CEO Gordon van Welie said.

"The construct assumed that society would be tolerant of occasional shortages and high prices to allow market incentives to work," van Welie said. "In practice, we have learned that the theoretical construct made assumptions that were inaccurate. Specifically, it assumed the proper price formation in the energy market, which has been stymied by price caps and externalities that have not been priced. This has led to the need to replace the missing money."

It also ignored the need for a reserve margin, and in that gap came the capacity markets. Both ISO-NE and PJM have used three-year forward markets, but van Welie said his RTO is working on a prompt, seasonal design that is better equipped to deal with the realities the system is facing.

"The seasonal pricing will reflect the dynamic changes and constraints in the regional power system, provide the economic stimulus to drive bilateral trading and discipline wholesale buyers who have not covered their share of the resource adequacy objective," van Welie said.

The new construct would require support from the states, reduced barriers to entry and substantial bilateral trading to manage volatility and support investment, he added.

PJM's markets have generally worked well in the past, with its capacity market helping to bring online 50 GW of new resources that includes significant renewables and 8 GW of demand response since it launched in 2007, CEO Manu Asthana said.

"So, it's not something very lightly that we would want to move away from," Asthana said. "I think they have worked, but — and there's a 'but' — as you know, we've been expressing resource adequacy concerns for some years now, and they're driven by generator retirements, slow new entry and accelerating demand growth."

Artificial intelligence is effectively just a "toddler" at this point, with ChatGPT launching less than three years ago, Asthana said. The technology is only to grow, and Asthana said he believes it will change the world — and in the process lead to much higher demand for power.

Other regions have seen their once large reserve margins shrink down to their minimum targets, and that is likely to remain the case.

"We hit minimum planning reserve margins in 2022; we've been treading water to maintain that level ever since," MISO Senior Vice President Todd Ramey said. "I think that's the new normal for our region. All of the incentives do not point to excessive planning reserve margins."

A key way MISO keeps track of resource adequacy is surveys it conducts with the Organization of MISO States, which represents states that are largely vertically integrated. The latest survey June 6 will show the industry in the region has work to do to maintain its reserve margin target next year and for the rest of the decade, Ramey said.

A longer-term 20-year assessment from a couple years ago showed only renewables coming online, which would have left the grid short of key reliability services, but Ramey said that has changed for the next long-term assessments as states have added more dispatchable resources to their plans.

For states that have ceded more of the control to FERC, the options to ensure reliability are more limited, with van Welie suggesting some kind of financial hit is needed, such as a penalty baked into the market, or just letting scarcity pricing occur in the spot market.

While restructured states have given FERC more control over resource adequacy, none of them under its regulation has gone as far as to Texas, where the standard utility has been eliminated, leaving large parts of their customers still on utility service. Asthana suggested states could change the rules set for utilities to procure supplies for those customers to boost bilateral trading and supplement the wholesale market.

"Because a lot of the load clears through state-run auctions, I think our states have the ability to try to hedge their consumers through those auctions for capacity," Asthana said. "And I think those hedges and those bilaterals will also incentivize new generation, and those are conversations we're having with our states."

State	New Entry Placed Into Service Since 2015 (UCAP MW)	Deactivations** Since 2015 (UCAP MW)	Net New Entry Placed Into Service Since 2015 (UCAP MW)	Resources With Executed Interconnection Agreements/WMPA (Planned Resources) but Not In-Service (UCAP MW)	Net New Entry Since 2015 with Planned Resources (UCAP MW)
Delaware	243	441	(198)	79	**(119)**
Illinois	3,277	3,016	261	984	**1,245**
Indiana	915	820	95	1,820	**1,915**
Kentucky	60	907	(847)	99	**(748)**
Maryland	2,078	3,114	(1,037)	788	**(249)**
Michigan	933	-	933	43	**976**
New Jersey	2,074	4,696	(2,622)	773	**(1,849)**
North Carolina	196	270	(74)	196	**122**
Ohio	5,582	9,663	(4,081)	1,853	**(2,228)**
Pennsylvania	9,025	5,543	3,482	439	**3,921**
Tennessee	-	33	(33)	-	**(33)**
Virginia	3,850	4,211	(362)	1,612	**1,250**
West Virginia	163	1,353	(1,190)	1,565	**375**
TOTAL	**28,395**	**34,068**	**(5,673)**	**10,251**	**4,579**

A chart PJM filed for the FERC technical conference laying out changes in capacity by state over the previous decade. | *PJM*

State of PJM's Markets

After an initial panel of ISO/RTO CEOs, the technical conference started focusing on regions, and PJM got the most attention, with three panels taking up more than half a day.

Commissioner Chang noted PJM has seen some of the largest concerns, but paradoxically, it has seen some of the lightest renewable power development, with 93% of its generation still conventional.

Given that PJM is going through more retirements of conventional generation, and most of the new developments are renewables, the mismatch in retirements and replacements is a concern for the near future, and the RTO already has to start planning for it, said Vice President of Market Design and Economics Adam Keech. On top of that, PJM has several hot markets for data centers, with the resulting demand growth acting as an accelerant to every other issue it faces.

Data centers are looking for highly reliable, 24/7 power, but a recent study from Duke University showed that they can be flexible if they use on-site resources such as batteries to participate as demand response, said LS Power Senior Vice President of Wholesale Market Policy Marji Philips. (See *US Grid has Flexible Headroom for Data Center Demand Growth*.)

"It's really only the times the system is stressed that you need the thermal generation," Philips said. "The problem is when it's stressed, you need it all. And PJM, as Adam said, is seeing a retirement of those resources."

Renewables are dominating the queue,

and the most economical of those are going to be built and will benefit the grid and consumers, PJM Independent Market Monitor Joe Bowring said.

"All I'm saying is that there's a baseline level of dispatchable resources you need for reliability to meet the demand during the high expected unserved energy hours," Bowring said. "So, I mean … low-marginal-cost energy is great for customers, but it doesn't meet that same reliability."

The resource adequacy issue and consumer costs in PJM have caused some to question longstanding policies on the market. (See *Utilities Pushing for a Return to Owning Generation in Pennsylvania*.)

But PJM Power Providers President Glen Thomas doubted Pennsylvania will change course and said Ohio just reaffirmed its market-centric policy with a recent change in law. Illinois, Maryland and New Jersey all restructured, and they have moved to a middle path, relying on the markets while being more active in picking resources, which he argued led to the retirements of others.

"They've largely been able to do that because of the tremendous surplus that Pennsylvania has built up," Thomas said. "And I would also add that Pennsylvania would never have been able to build that surplus under a vertically integrated [integrated resource plan] regime. There's no way state regulators would allow the system to be that overbuilt."

Now that excess capacity is bailing out even Virginia, which is a vertically integrated state that is dealing with massive demand growth from its world-leading data center market, he said.

Chair Christie, who was a regulator on Virginia's State Corporation Commission for years before joining FERC and is a strong proponent of its regulatory setup, said traditional regulation worked for years there and only ran into the same issue around unexpected demand growth that is causing issues around the country.

"That was a decision driven by policies adopted by our legislature to give tax subsidies to data centers and other attractions, which the utility commission had nothing to do with," Christie said. "So, the IRP system is not the reason, as Glen said, Virginia is now a big importer."

The prices are getting too high even for Pennsylvania, PPL Chief Legal Officer Wendy Stark said. The capacity market cleared at $270/MW-day last time, which was enough for Gov. Josh Shapiro (D) to file a complaint. That led to a settlement capping the next two auctions at $325.

"That also is not enough to incent new generation, so customers will be paying even more than they are now," Stark said, adding that prices need to be at $500 to $600/MW-day. "That's a problem, and as a utility with that obligation to serve, we at this point are really dependent upon the PJM capacity market. I will tell you at this point that feels like a single point of failure for us."

Pennsylvania and other states restructured because cost-of-service regulation proved inefficient, which meant high costs as well, Bowring said.

"The idea that a regulated generator, because it's subject to a regulatory process, is going to do things more efficiently is questionable," Bowring said. "The markets have demonstrated the reverse for quite some time. So, I didn't think I'd be here jumping up to defend the PJM capacity market."

Bowring also doubted that the mandatory market will ever be meaningfully substituted with bilateral deals because it effectively forces much of that activity into the capacity auctions.

"Cost-of-service regulation worked to provide reliability for 100 years," Bowring said. "It could certainly do that. I think it did it at a higher cost than markets."

Capacity is a political construct, and states should be given more say in how it is managed, said Jacob Finkel, deputy secretary of policy in Shapiro's office. The 14 states that are in PJM are swamped by the sheer number of stakeholders in a process that does not give them major formal input, he said.

"Most of our ability right now revolves around whatever goodwill we can build with PJM around working with the board and working with management, and it should be more than that," Finkel said.

With the disconnect between price signals and new supply as the balance is only getting tighter, Finkel suggested that PJM needs to embrace resources such as virtual power plants (VPPs) and grid-enhancing technologies (GETs) that can be added to the grid quickly.

"All the acronyms should be deployed," Finkel said.

Getting such resources will help, but after the quip, Finkel said ultimately if the issues around the market cannot be resolved in a way that is fair for ratepayers, Pennsylvania could move back to its own planning. ■

FERC Focuses on Midwest, Northeast in Day 2 of RA Tech Conference

By James Downing

While the first day of FERC's resource adequacy technical conference was almost entirely focused on PJM, the commission zoomed out on the second day, June 5, with several panels examining ISO-NE, MISO and NYISO. (See related story, *FERC Dives into Thorny Resource Adequacy Issues at Tech Conference*.)

In general, the grid needs to see fewer retirements and more new resources with the right characteristics to maintain reliability, said Todd Snitchler, CEO of the Electric Power Supply Association.

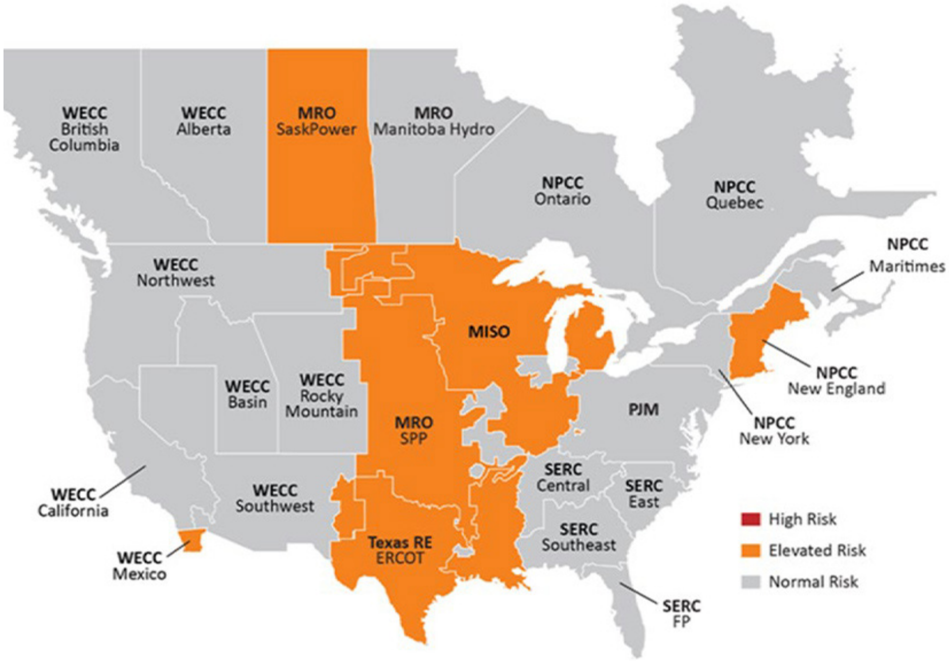
"That's not to suggest that … if plant 'X' retires, it needs to be replaced with exactly the same type of unit [or] type of fuel source," Snitchler said. "But the performance characteristics of the things that are coming on the system have to ensure reliability and do so cost effectively."

The whole system needs new resources, whether it's the power plants or new transmission and distribution, and Snitchler sees that need in three phases. The next five years are seeing load growth, but most of the new generation that will come online is already well down the development path. The five years after that are long enough that new capacity can help, while anything further out is too far ahead to forecast accurately.

"If we can meet the objectives for the first block and the second block, I think the third block becomes far less concerning," Snitchler said. "And, so, as we look at these numbers and how we're going to meet this short- and medium-term obligation to get resources on the system, I think that's where the focus needs to be from all parts of the value chain."

Why This Matters

The three grid operators face their own unique issues stemming from their geographies and the political preferences of their states.



NERC's Summer Reliability Assessment showed elevated risk for much of the middle of North America, along with parts of the Eastern and Western Interconnections. | *NERC*

FERC Chair Mark Christie asked what needs to be done in light of the issues, which Snitchler answered by noting that it has been about 18 months since data center-led demand growth became the topic in the industry. Now it is important to get the interconnection queues, siting and permitting right.

"At the end of the day, if we want to solve the problem, you've got to accelerate the projects that are ready to go in order to make sure that they can deliver the electrons that are needed to power the country," Snitchler said.

FERC was holding the tech conference just before MISO and the Organization of MISO States released their annual survey of resource adequacy. (See related story, *MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey*.)

Recent changes to the RTO's capacity market, such as replacing the vertical demand curve with a sloped curve, have made MISO Independent Market Monitor David Patton, president of Potomac Economics, confident that it will maintain reliability going forward. The old market design contributed to 6 GW of merchant power plants retiring in MISO, he said.

"The merchants retired," Patton said. "It caused a one-year shortage in the Midwest, and then everybody figured out: 'Hey, this is a real problem; our market isn't facilitating investment.' And they finally, after 15 years, adopted the reliability-based demand curve."

The first auction cleared about 85 to 90% of the cost of new entry (CONE) when the old model would have cleared at 10%, Patton said. Now the market works for merchants, and rather than interfering with state integrated resource plans, it facilitates them, he said.

One other rule that should be universal is the marginal accreditation of resources, Patton argued, because that provides IRP planners and merchant developers with the right information on the grid's needs.

"Once you implement the marginal accreditation, I think you can have a high degree of confidence that both the markets and the planning processes in regulated states will adjust to conform to the reliability attributes that drive what we need and facilitate the investment that we need," Patton said.

"Correctly aligned" market rules would be good for development because it would offer more certainty, American Municipal Power Vice President Steven Lieberman said. But none of the organized markets offers enough certainty, he argued.

"These capacity constructs provide at most a one-year price signal," Lieberman said. "Nobody's building generation for a one-year price signal. And if it's a seasonal design, you're not building it because the price in the summer was high. Here, you're building because you have a long-term view."

Patton disagreed with that assessment, pointing to the one domestic market FERC does not regulate: ERCOT, with its energy-only market.

"They don't provide anything beyond the day-ahead market, right?" Patton said. "And yet, people are still investing. They're investing because they understand the market design and they can forecast market revenues of different types of units going out 20 to 30 years in the future. And that's why it's important for the capacity constructs to be efficient."

The prices in capacity markets can be forecast decades into the future, but investors discount those prices heavily because of regulatory uncertainty. They might not be here in another decade or two, Patton said.

"But if we get to the point where we have well-structured capacity markets that that are robust and durable, where we're not creating the concern that maybe they'll go away, or maybe they'll fundamentally change, then I think investors can rely on their expectations, and those expectations will fuel bilateral contracts," he added.

One resource that ERCOT has been able to attract — as has California — is energy storage, American Clean Power Association Vice President Carrie Zalewski said.

"I think we just need to pause for a second and recognize the powerhouse, the Swiss Army knife, that storage is," she added. "It's fast; it's flexible; it's dispatchable. It allows for frequency regulation, grid stability, virtual inertia [and] black start. The technology continues to get better; it gets more efficient."

Zalewski also argued that FERC should not disregard many of the projects in the queues that will be ready to go and help over the next critical period.

"Those projects are in a much better place than starting over from scratch and building something new," she added.

ISO-NE and NYISO

The two organized markets operating in the Northeast are not hotbeds of data center development, but they are facing their own resource adequacy issues.

NYISO is expecting a combination of large loads, increasing electrification and constraints on the supply side to lead to narrowing reserve margins, COO Emilie Nelson said.

"We're also seeing a shift in what we must solve to continue to provide that reliable electric grid," Nelson said. "One of the significant changes we're preparing for in New York is to move from a summer-peaking to a winter-peaking system."

NYISO expects its winter peak to go up by 14 GW by 2040, which will put more pressure on a natural gas system already strained to meet demand from power plants and heating during cold snaps.

ISO-NE faces the same problem. Recent analyses give the RTO into the early 2030s before its winter resource adequacy leads to reliability problems, noted Connecticut Department of Energy and Environmental Protection Commissioner Katie Dykes. There is enough time to avoid those problems, she said, but the region's preferred answer on the supply side has some major issues of its own.

"We've had some very disappointing and challenging news on the offshore wind front, not just in terms of interest rates and general inflationary pressures, but now a federal executive order and tariffs and uncertainty around tax credits that's making the path for that resource, which is very valuable for addressing winter reliability, have a more uncertain path," Dykes said.

On the positive side, the states in New England have been cooperating on ensuring a reliable, affordable grid that meets their policy goals.

"I think one of the most important things will be to continue to have a clear path here at FERC," Dykes said. "In terms of ensuring that we don't see new barriers like a resumption of MOPR [the minimum offer price rule] or something like that, that would challenge the abilities for states and the ISO to work together on these solutions that we urgently need to deploy."

It is harder to build in New England, and it would be very difficult to get new pipelines in place to deal with the winter reliability issues in the next five years, said Philip Bartlett, chair of the Maine Public Utilities Commission.

"The states have come together and decided we want to build some transmission up into Northern Maine to unlock resources that are there," Bartlett said. "That's a great benefit, particularly given the delay in offshore wind. But the earliest that's likely to come online is 2035. So that is a long-time horizon when you're dealing with resource adequacy challenges."

Ideally, the states and the RTO will work together to develop a process that will evaluate resource adequacy and explore the tools the region has to address it, Bartlett said.

"If the states decide we want to go all-in on a particular resource or particular transmission approach, we need to figure out how to fast-track them to get it moving faster through the ISO process," he added. "I think states need to think about, as we're doing some of our state procurements, how does that fit in with resource adequacy? Should we be bumping up, for example, investments in storage or in certain kinds of other resources or demand response or other tools that could help us buy some time to deal with the problem?"

Michelle Gardner, NextEra Energy Resources' executive director for the Northeast, agreed that the region needed to think broadly when it comes to resource adequacy. Unlocking Northern Maine, with its cheaper land and renewable resources, will help, she said.

"I think we need to take advantage of every tool in our toolbox," Gardner said. "I think we need to take advantage of every effort to move forward." ■

Trump Replacing FERC Chair Christie with Laura Swett

By James Downing

[EDITOR'S NOTE: An early version of this story was published in our previous issue. This is an updated version that was posted online after that issue was published.]

FERC Chair Mark Christie's tenure running the commission is coming to an end, as President Donald Trump on June 2 nominated Laura Swett of Vinson & Elkins to replace him.

"I learned this evening from a media inquiry that President Trump has appointed Laura Swett to replace me when my term expires," Christie posted on X. "I congratulate Laura and wish her the best. I will remain in office for a few weeks after June 30 to help get key orders out."

Christie's term ends June 30; if confirmed, and depending on when she is sworn in, Swett would be able to serve a full five-year term. Another seat remains open since former Chair Willie Phillips stepped down earlier this year, but that term would only extend into 2026. Any new commissioner in that seat would need to be effectively nominated and confirmed twice to serve longer.

Swett's *nomination* has been referred to the Senate Energy and Natural Resources Committee. She has previous experience at FERC serving on the staff of Chair Kevin McIntyre and former Commissioner Bernard McNamee, both Trump nominees in his first term. She also worked at the Office of Enforcement, according to her LinkedIn page.

Former FERC Chair Neil Chatterjee, who overlapped with both Swett and Christie on the commission, *called* the news bittersweet on X.

"I adore Laura Swett and believe she will be an excellent FERC chair (if given the chance by OIRA and OMB)," Chatterjee said, referencing the White House's Office of Information and Regulatory Affairs and Office of Management and Budget. "But Christie is a patriot; all he did was run the agency well. He's a veteran who has dedicated his life to serving America. He deserved better."

The Trump administration has been skeptical of independent agencies generally, reportedly telling Phillips it would fire him if he did not step down, leading to his resignation. Trump issued an executive order in February trying to bring FERC and other similar agencies more under his control. (See *Trump Claims Authority over Independent Agencies in Executive Order*.)

Laura Swett | *Vinson & Elkins*

What's Next

FERC Chair Mark Christie's term ends June 30. As his replacement, Swett could serve a full five-year term on the commission.

Christie spent his first press conference as chair addressing that executive order and has repeatedly answered questions on it since. While he put some of it in the context of normal relations between a president and FERC, he also made it clear that he had to follow the laws that govern FERC. (See *FERC's Christie Says Existing Policies Can Align with Trump's Order*.)

One area Christie made clear then that FERC could not tolerate was *ex parte* communications on cases pending before it.

"We do not allow *ex parte* communications; that would violate the [Government in the] Sunshine Act," Christie said at the press conference in February. "It would also violate everything I know about due process in contested proceedings going back to being a state regulator. We didn't allow it in Virginia, so we're not going to start allowing *ex parte* communications."

Reactions

"I think it's great that Laura has been nominated by the president," McNamee said in an interview. "I think she'll do a fantastic job as a commissioner, and I knew that because she provided great and sound advice to me when she was my attorney adviser, when I was a commissioner."

Swett advised McNamee on pipeline issues when she was his staffer, and much of her work at Vinson was in that area.

The issue of environmental assessment in pipeline permitting has caused some partisan splits among commissioners in the last decade, especially around how much attention FERC must pay to the downstream greenhouse gas emissions.

Former Chair Richard Glick's efforts to update the pipeline approval process after some losses in the courts wound up sinking his renomination in 2022, but a recent Supreme Court decision means those debates are likely coming to an end regardless of FERC's composition.

In *Seven County Infrastructure Coalition v. Eagle County*, issued May 29, the majority found that the U.S. Surface Transportation Board was right to not consider upstream and downstream effects from approving oil shipments over rail. In a post on X, Christie called the decision "the most important permitting reform in decades."

Trade associations and other groups active before FERC released statements on June 3 congratulating Swett for the nomination.

Americans for a Clean Energy Grid Executive Director Christina Hayes offered congratulations in a statement and argued for continued action on transmission.

"In her previous stints as a senior leader at FERC, she worked on policies that emphasized grid reliability," Hayes said. "At a time when American energy demand is set to skyrocket, no policy area is as essential to our energy dominance as transmission planning reform. ACEG's coalition of transmission policy advocates across the political spectrum looks forward to working with Swett in her new role and urges continued FERC leadership in implementing the bipartisan consensus behind Order No. 1920. America's energy dominance depends on it."

In addition to congratulating Swett, Electricity Customer Alliance Executive Director Jeff Dennis thanked Christie for his service and for keeping reliability at the top of FERC's priorities.

"We look forward to working with her and the rest of the commission to advance customer-centric solutions that support the power system expansion our nation needs to meet the demands of a growing digital economy while keeping energy affordable for all customers," Dennis said. ■

Consumers Energy Seeking Compensation for Keeping Campbell Open

By James Downing

Consumers Energy filed a complaint with FERC against MISO seeking compensation for keeping open the J.H. Campbell coal plant this summer as ordered by the U.S. Department of Energy under Federal Power Act Section 202(c) (*EL25-90*).

The utility filed the complaint on June 6 because MISO's tariff lacks a method to ensure that it gets paid for reversing the retirement of the 1,400-MW coal plant, which had been set to shut down on May 31. Instead, Consumers has been actively bidding the plant into MISO's markets and producing energy there when dispatched. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

The firm also said it has procured fuel, done review and planning for maintenance, and taken other steps to comply with the order. It has set up an account to track all those costs.

DOE's order calls on Consumers and MISO to file any needed waivers with FERC to ensure the firm gets paid for keeping the plant open.

Consumers was not requesting any specific dollar figure in the filing, saying it will make a filing when DOE's emergency order is over that explains the just and reasonable costs it incurred in running the plants, minus market revenues.

The utility and MISO agree that the tariff lacks a mechanism for the utility to recover costs from complying with the order, and MISO cannot unilaterally offer the utility a rate agreement under Section 202(c). The utility asked for fast-track processing of the complaint and to make the compensation mechanism effective May 23, the date of DOE's order.

"As soon as the DOE order was issued, Consumers Energy began incurring and will continue to incur costs to comply with the DOE order's directive to 'take all measures necessary to ensure that the Campbell plant is available to operate' for the duration of the DOE order," the utility said. "The precise order costs will not be known until after the DOE order expires on Aug. 21, 2025."

FERC has the authority under Section 202(c) to approve compensation for any plants required to stay open under the law. That authority is supplemented by Section 309, which gives the commission the "power to perform any and all acts, and to prescribe, issue, make and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this act." That part of the law gives FERC the authority to set up rules for cost recovery before those costs are fully known, Consumers argued.

The utility said the costs should be assigned to MISO Zones 1 through 7, which make up the RTO's northern and central regions, the reliability of which DOE said it was addressing with the order.

"Michigan load will of course pay its fair share of Consumers Energy's order costs (net of market revenues) because, as the DOE order points out, MISO Zones 1-7 (i.e., the northern and central zones) include Michigan. But Consumers Energy believes that, whatever the order costs turn out to be after netting market revenues, they should be allocated beyond the state of Michigan," it said. "Consumers Energy customers are already paying for the cost to fulfill the capacity needs of Zone 7."

J.H. Campbell Power Plant in Michigan | *Consumers Energy*

Why This Matters

FERC has authority over payments under Section 202(c) of the Federal Power Act, but MISO's tariff lacks a way to implement that.

DOE's order noted that while the plant's retirement was approved by MISO, and Michigan has adequate supplies without it, the north and central zones are still facing elevated reliability risks this summer.

Beyond the FPA, the government is constitutionally required to pay Consumers for running the plant the summer, the utility argued.

"Specifically, the Fifth Amendment Takings Clause bars the federal government from taking private property for public use without just compensation," Consumers said.

The utility filed its complaint under Section 206, but it said this was done to cover its bases. In the event FERC finds it lacks the authority under sections 202(c) and 309, it can find the MISO tariff unjust and unreasonable under 206.

"Consumers Energy will incur costs associated with the DOE order, but the MISO tariff does not presently include a mechanism that would allow MISO to compensate Consumers Energy for such costs or allocate those costs to load in the MISO region," it said. "The MISO tariff is thus unjust and unreasonable as applied to Consumers Energy and its compliance with the DOE order, and the commission should order MISO to adopt a tariff revision to provide a cost recovery mechanism for Consumers Energy's order costs net of market revenues." ■

ACEG: Comprehensive Transmission Planning Saves Consumers Money

By James Downing

Rising demand means the U.S. needs to expand the transmission grid, and doing so will also keep power prices affordable, according to a report released June 9 by Americans for a Clean Energy Grid.

"We find that comprehensively planned, high-capacity transmission saves consumers money on electric bills, reduces congestion on the grid, unlocks access to lower-cost generation, avoids costlier investments in new generation or lower-capacity transmission and improves overall system efficiency," the report says.

"*Large-scale Transmission Deployment Saves Consumers Money*," prepared by Grid Strategies, says that large-scale, proactive and collaborative planning and development are essential to savings for customers. Proper planning cuts costs by decreasing the need for generation and transmission investments overall, while allowing the grid to be operated more efficiently.

"The affordability of electricity supply depends in no small part on the efficiency and cost effectiveness of the associated transmission expansion," the report says.

Well-planned, high-capacity transmission could save residential customers $6.3 billion to $10.4 billion across the country after taking the cost of new power lines into account. Across all customer classes, the savings are estimated at $16.8 billion to $27.7 billion.

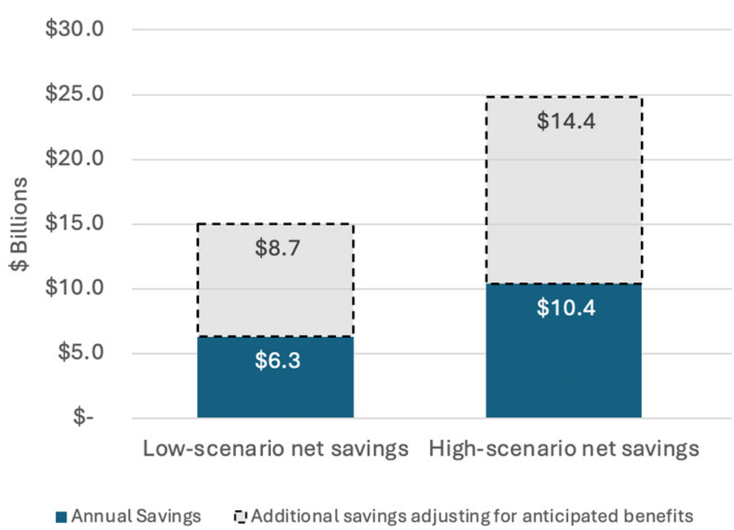
Transmission planners often underestimate benefits in their initial planning studies, and ex post assessments of consumers savings are often 20 to 40% higher. Applying that to potential annual savings for residential customers brings the range up to $8.7 billion to $14.4 billion, the report says.

Most of the estimated savings come from lower production costs, which means savings from lowering the cost of the power supply by accessing low-cost generation.

Investing in transmission as the report suggests would raise the transmission component of bills by 2% overall, which is a $19 increase annually. But that comes with a 3% cut in generation costs, which translates to $92 in savings annually for the average household.

The report based its estimates on annual savings in recent transmission planning efforts in several regions of the country, but that does not reflect the optimal buildout in doing well-planned, coordinated and cost-effective investments. Some regions are not engaged in that kind of planning at all.

"Extrapolating from a combined set of the recent portfolios planned by MISO discussed in this report, which are among the most robust examples of well-planned, high-voltage transmission, gives a better idea of the full savings consumers might see from more holistic, comprehensive transmission planning," the report says. "This analysis reveals that every residential household in the country could expect over $100 in net savings on their annual electric bill if this type of planning were the norm nationwide."



| ACEG

Beyond the savings, transmission supports a reliable, resilient and competitive power system, which benefits national security because of the race to develop artificial intelligence and the high-demand data centers it requires, the report says. A lack of transmission can delay electricity for consumers, slowing economic growth and jeopardizing national goals.

Expanding transmission also means more options to manage the uncertainties facing the power sector today, such as unpredictable load growth, volatile fuel prices, policy uncertainty, uncertain cost trajectories for costs of different types of generators and extreme weather.

"The reality is that price spikes can be crippling for electricity customers, even if they appropriately reflect market design and supply-and-demand fundamentals," the report says. "As a commodity, electricity is different. It requires hedging and long-term planning that reflects the importance of the service to residential, industrial and commercial customers, as well as the relative degree of price inelasticity for American households. Well planned, high-voltage transmission investment is an essential piece of this puzzle." ■

Why This Matters

The report highlights the economic benefits of comprehensive planning to expand the grid to help meet higher demand, which include keeping prices lower than piecemeal planning and adding generation alone.

'Pathways' Bill Passes California Senate on 36-0 Vote

SB 540 Supporters Express Concerns About Amendments, Seek Changes in Assembly

By Robert Mullin

The California bill to implement the West-Wide Governance Pathways Initiative's Step 2 proposal to allow CAISO to relinquish market governance to an independent "regional organization" (RO) passed the state Senate on June 4 on a 36-0 vote, with four members abstaining.

SB 540 was approved after 40 minutes of floor debate in which several senators expressed concern about the extensive amendments added to the original bill, particularly a provision creating a new "Regional Energy Market Oversight Council" responsible for ensuring CAISO's participation in a regional energy market that "serves the interests of the state." (See *Amended 'Pathways' Bill Boosts — and Complicates — Calif. Protections*.)

The new council would be authorized to mandate withdrawal if those interests are compromised.

Those senators sought assurances that the bill's sponsors, Sens. Josh Becker and Henry Stern, both Democrats, would work with members of the state Assembly to return the bill to something closer to its original form.

But other senators said they wanted to ensure preservation of an "off-ramp" from the RO, expressing worry that the ISO's participation could compromise California's environmental and clean energy policies, particularly in the face of the Trump administration's efforts to support coal-fired generation.

Becker assured his colleagues the bill would not increase California's exposure to federal political interference, but did point to the risks of the state losing potential "partners" on the electricity grid to "a market out of Little Rock" — SPP's Markets+, the competitor for participants to CAISO's Extended Day-Ahead Market (EDAM).

"Make no mistake: if we do not act, we will be worse off," Becker said.

'Strong Coalition'

During the debate, Sen. Tony Strickland (R) called the recent amendments to SB 540 "very problematic" but expressed confidence that Sens. Becker and Stern would "work out some of these problems" as the bill advances through the lower house.

The California State Capitol in Sacramento. | *Shutterstock*

Why This Matters

The Pathways bill now will move on to California's Assembly, where it likely will face another round of amendments.

Strickland pointed to the "strong coalition" backing the bill, including labor and business groups.

"I haven't seen a coalition like this in a long time, and I've been on [Senate] Energy Committee going back 13, 14, 15 years," he said. "Because everybody understands status quo is not an option. We need to get this fixed. We need to move forward. We need to make sure energy is reliable for all California residents."

Sen. Angelique Ashby (D) opened her comments saying she likes to "brag" about the publicly owned utility that serves her constituency, the Sacramento Municipal Utility District (SMUD), and voiced concern that SMUD had changed its position on the bill in light of the amendments.

Ashby asked the bill's authors how they will "get from where you are now back to a space where you can earn the support of the one of the most trusted entities in the state of California, which is SMUD."

"I know SMUD, other than [having] issues with the bill, would like to see it move forward, and I'm committed to working with them going forward," Becker said.

Sen. Christopher Cabaldon (D) said a small portion of his constituents are served by SMUD and echoed Ashby's concerns, urging "less work" to be done on the bill.

"Because the problem here is all of the benefits of this bill — and they are numerous and profound — depend on us actually joining with the region and the region joining with us," he said. "I think the problem that I hope we will work on to resolve in the Assembly is that we cannot replicate all of the state rules and interests and what have you, as though the rest of the world is just waiting for California to allow them to be partners."

Sen. Rosilicie Ochoa Bogh (R) said she supported the bill in the Senate Energy Committee "because it reflected a bipartisan, holistic compromise. Literally every group, as mentioned earlier, related to energy, visited my office, and nearly all were in alignment. Not all were pleased, but they were aligned."

But Ochoa Bogh said the proposed oversight council in the amended bill "fundamentally alters the governance structure" by giving the body "extraordinary authority" over California's participation in a regional market. She said that would "inject an uncertainty into what should be a technical, market-driven process" and compromise long-term resource planning if the state were "suddenly withdrawn," threatening grid reliability and affordability for residents.

'Energy Island'

Sen. Thomas Umberg (D) said SB 540 is "a very difficult bill" because it brings up "a clash of interests that is very difficult to reconcile" — namely, the differing views on climate change between California's leaders and the Trump administration.

"The challenge is that, once we're in [the RO], it may be very difficult to leave, either legally or practically, because we become so reliant on the grid. And it also vests California in a place where, potentially, the current administration can wreak havoc on California," Umberg said.

Sen. Suzette Martinez Valladares (R) recalled a previous visit to CAISO was a "phenomenal experience" before noting the ISO has "urged" for a "regional approach." She warned that California faced risking becoming "an energy island" like Texas, but also said she wanted additional clarity around the role of the proposed oversight council.

Sen. Ben Allen (D) added his voice to supporters of the bill but said inclusion of the oversight council was "bizarre" and represented a "bad direction," in part because it would make withdrawal from the RO a "governor-dominated" decision. He pointed to a suggestion that the decision should come down to "some sort of supermajority vote in the legislature."

Sen. Aisha Wahab (D) expressed the greatest reservations about SB 540, saying creation of the five-member oversight council is "not enough" and that she was concerned "that we're not going to bring it back to the legislature to have a full picture of what this regional organization will actually look like."

"If it is that we have a lot of confidence in a regional organization — the fact that it won't impact the RPS and won't take away green jobs and won't force Californians to subsidize an organization they no longer have control over — then we should be able to review the facts once we have more concrete evidence," she said, later abstaining from voting on the bill.

Sen. Anna Caballero (D) said she favored "regionalism" because "I think our weather patterns and the energy that we can create regionally is diverse enough, so it'll benefit California." But she also called for the bill to include the option for an "off-ramp" from the RO to avoid tying the hands of a future governor and legislature.

In his closing speech stumping for his bill, Sen. Becker reminded his Senate colleagues that SPP's Markets+ has been able to attract more participants in recent months.

"So, if they're able to sort of pull something together, we'll end up isolated — so we need to do this," he said. "I appreciate everyone who's had their input and wants to keep working on this going forward."

Reactions

Clean energy groups that have backed the Pathways Initiative commended the California Senate for advancing the bill while also urging changes to the bill as it moves through the Assembly.

"California can't afford to go it alone when it comes to meeting skyrocketing energy demand while tackling the energy affordability crisis," Edson Perez, California lead at Advanced Energy United (AEU), said in a statement. "We need to be able to keep the lights on in the fourth-largest economy in the world without charging ratepayers an arm and a leg. Joining a robust Western regional energy market is essential to keeping energy costs under control while still spearheading the transition to clean energy."

AEU said bill supporters "remain committed to ongoing collaboration to ensure the final version reflects the shared priorities of the diverse coalition engaged in this effort for regional energy collaboration."

"Today's Senate vote is an important step in a long process to ensure California is at the forefront of a fast-moving revolution in how electricity will be bought and sold across the West," Katelyn Roedner Sutter, California state director at the Environmental Defense Fund (EDF), said in a statement. "California cannot keep the lights on or solve the climate crisis alone — we need an electricity system with diverse clean resources that can withstand simultaneous extreme weather events."

Roedner Sutter said EDF shares "significant concerns about recent bill amendments that undermine the benefits of California's participation in a Western market and urge California leaders to act decisively to avoid losing more trading partners to a competing Arkansas market." ■

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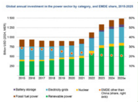

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CAISO EDAM Congestion Revenue Proposal Gains Support

By David Krause


| © RTO Insider

Stakeholders are mostly supportive of CAISO's *proposed new method* for allocating congestion revenues in its Extended Day-Ahead Market (EDAM) after months of workshops and multiple proposals on the topic, according to comments filed with the ISO ahead of a June 2 deadline.

The congestion revenue issue is a top priority for CAISO this year. The "expedited" initiative began in March after Powerex published a paper contending that EDAM contains a "design flaw." (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

The primary question is whether certain congestion revenues should be allocated to the balancing authority area in which the costs accrued or to the neighboring area where the transmission constraint is located, specifically in cases in which parallel — or loop — flows occur.

Under EDAM's existing rules, congestion revenues will be allocated to the BAA containing the constraint. The new method would allocate a portion of congestion revenue, such as network integration transmission service (NITS) rights, to the BAA where the energy is scheduled.

CAISO committed to making the new method temporary to allow the ISO to maintain its go-live target for the FERC-approved market in 2026. "This narrowly tailored design change appropriately addresses congestion revenues allocated associated with parallel flows to ensure a just and reasonable congestion revenue allocation for EDAM go-live," the proposal says.

The ISO noted that stakeholders "were divided on the temporal aspect of the design." Several argued that it should establish a concrete timeline for consideration of a long-term solution, though without a hard sunset date for the temporary method.

The Balancing Authority of Northern California said it generally supports the draft final proposal, published May 19. It is "a workable interim solution while ... CAISO and stakeholders take the necessary time to develop a more durable approach that addresses the identified issues surrounding incentives for self-scheduling," BANC General Counsel Tony Braun wrote.

CAISO's Department of Market Monitoring said it believes the new method is an acceptable transitional measure. While the department said it might create increased incentives to self-schedule that could reduce market benefits relative to the approved EDAM design, the implementation with the new allocation method "will still create market benefits relative to the current pre-EDAM market."

The Bonneville Power Administration also said it supported the proposal, although it too is concerned that the method potentially incentivizes increased self-scheduling.

Other stakeholders said the proposal is headed in the right direction but needs a few tweaks. San Diego Gas & Electric, for example, said that without additional analysis, it is challenging to evaluate with "any level of certainty whether this design supports market efficiency or minimizes cost shifts between the EDAM balancing authority areas."

"Although the flow patterns and market results from market simulation and parallel operations are likely to evolve significantly following go-live and as participants gain actual market experience, any reporting regarding the potential impact of the transitional methodology that CAISO can provide to participants would ground the working group efforts planned in 2026," SDG&E staff said in their comments. "SDG&E recommends CAISO prioritize providing this information to the extent it is possible."

CAISO plans to publish the final proposal June 6. It would then be reviewed by the CAISO Board of Governors and Western Energy Markets Governing Body during a special meeting June 19. ■

Why This Matters

The proposal is in response to a paper published by Powerex in February contending that EDAM contains a "design flaw" that could subject non-CAISO market participants to $1 billion in unfair congestion-related charges.

Meeting the Surge in Demand Without Sacrificing Affordability

EEI Members Discuss Challenges Facing the Industry During Annual Meeting

By Tom Kleckner

Southern's Chris Womack (left) and Exelon's Calvin Butler (right) egg on Evergy's David Campbell as he makes good on a losing Super Bowl bet. | © *RTO Insider*

NEW ORLEANS — The 1,300 attendees who gathered in the Big Easy for Edison Electric Institute's recent annual conference and thought leadership forum had little time for the city's 24/7 nightlife.

They had a problem to solve: how to meet the biggest surge in demand since the post-World War II boom without raising prices for their customers.

Incoming EEI Chair Calvin Butler, Exelon's CEO, said during the June 2-4 conference that the industry stands at "an exciting crossroad."

"New challenges, historic levels of investment and burgeoning technologies like artificial intelligence are redefining America's energy future," he told the membership. "I look forward to working with EEI and its member companies to ensure that we continue to meet the evolving needs and expectations of our customers, while at the same time working to keep their bills as low as possible."

"This is a remarkable time for our industry," said Butler's predecessor, Portland General Electric CEO Maria Pope, in opening the conference. "The extraordinary, once-in-a-generation demand for electricity is real, and it is here now."

"It is remarkable the amount that we have invested in new technologies and resource adequacy," she added. "We have seen our grid change at a pace and level that we have never seen before. We need to figure out how to get more out of the system while thinking differently."

EEI Chair Calvin Butler, Exelon | © *RTO Insider*

The U.S. Energy Information Administration *said* in January that the nation's electricity consumption grew by 2% in 2024 and will continue to grow at that rate in 2025 and 2026. It will be the first three years of consecutive growth since 2005-2007, with much of the demand coming from battery manufacturing operations and data center consumption.

One of the key questions, of course, is how much of that demand will actually show up — that and whether there will be enough resources added to the grid in time to meet the demand. (See related story *FERC Dives into Thorny Resource Adequacy Issues at Tech Conference*.)

"This is the question I was waiting for," Amazon Web Services' Vibhu Kaushik said during a panel discussion on increasing capital deployment to meet new demands from data centers, advanced manufacturing, electrification and large resilience programs.

"We're all here together, and we are excited because this demand growth is real," he said. "So why is the demand increasing? It's increasing because customers today are using more technology than ever before. So yes, demand growth is going to go up."

Asked the same question, Allen Otto, managing director of power, energy and renewables for Guggenheim Securities, said, "Nobody really knows, right?"

"Where we get concerned is not actually developing the assets to where we can unlock the economic potential that we have a number of industry areas," he said. "There are a number of projections that are out there, and at the high end, they are 4% year-over-year power demand growth for all those reasons that we're now familiar with. Even if it's half that, it's massive. It's massive, and part of the issue is if we don't move now, we're going to have challenges even getting there. We don't know exactly what the demand is going to be, but we do know that if we don't act now, we're going to fall behind our global adversaries and our allies, right?"

Congested generator interconnection queues don't help. A recent *Enverus study* found that in 2024, new projects had spent anywhere from 9.2 years (CAISO) to 3.8 years (ISO-NE) in the queue, an average of 6.2 years per grid operator.

"Why do we have 2.6 TW of generation, a lot of carbon-free energy waiting to be connected to the grid?" Kaushik said. "Carbon-free energy that can be built in 18 months is waiting for five to seven years to be connected to the grid. Demand that could be connected faster to serve customers for essential services is waiting to be connected. The grid should eventually be a plug-and-play platform for all customers and all generators."

Jeff Bladen, energy leader for Verrus, called for building out the grid, noting "there is no future" in which the industry benefits without "actually building stuff."

"I'm a sellout for building as much transmission as we can get approved. We're going to have to build more generation, right? At some point, you have to make electrons," he said. "What I like to tell folks is that it's important for us to get the most out of the grid we have while we're building the grid we need, right? If we're building large loads that are actually assets rather than liabilities, those will be assets for a very, very long time."

Tricia Pridemore, a member of the Georgia Public Service Commission, said meeting the demand is the topic of conversation among state regulators "morning, noon and night."

Maria Pope, PGE | © *RTO Insider*

Tricia Pridemore, Georgia PSC | © *RTO Insider*

She said her commission was first exposed to the concept of data center demand in 2023 — just as Georgia Power was bringing the Vogtle nuclear plant's third and fourth units to the grid at an *estimated cost of $30 billion*, more than double initial projections.

"[They] said, 'But wait. We need more energy.' You can imagine the five elected regulators just laughing them out of the office," Pridemore said.

But after getting into the integrated resource plan's process and meeting customers, the commission approved an IRP with 7.1 GW of new capacity in six months. Pridemore said it was the first IRP docket specifically developed for data centers and onshore manufacturing.

"We have before us right now another 1,500 MW of new capacity," she said. "We've developed a construct that gets these customers involved, that gives them a seat at the table, but most importantly, they're paying for it. We're constantly trying to build out this required and necessary infrastructure. … We've got to be able to rise to this occasion, but we can't do it off the backs of our residential rate payers. All 50 states have seen rates increase over the last several years, so now's the time for us to be creative as regulators."

Pridemore found a friendly voice in Louisiana Gov. Jeff Landry. He called for a "recalculation" of the regulatory environment, given the potential billions of dollars in new generation for his state.

"That's the problem that we have to solve: How do we meet the demand without laying it on the backs of the consumer?" Landry said.

Southern CEO Chris Womack said utility work has to change in a future where technology and AI are likely to play such a huge role. He said lessons learned will be important because "we're doing some things we never had to do before."

The industry will have to navigate its way through construction, permitting reform, "the chaos in D.C. … all kinds of the tariffs and trade and just so many external factors that are coming into play," Womack said.

"We will do this, but I think it's so important for us to really understand the reality of what we face, and the reality that's in front of us is going to be incredibly different," he said. "The technology is going to keep moving so incredibly fast, it's going to make us incredibly uncomfortable. We've got to … be comfortable doing incredibly uncomfortable things. … We're going to have to keep pressing forward to meet this moment, to meet the challenge that's in front of us. And we will, but I think it's going to be so incredibly important that we find a way to do this together, to do this collectively."

Industry Faces Tariff Uncertainty

The administration's global tariff war is complicating the electric industry's efforts to meet historic levels of increasing demand. During the final day of the conference, the government doubled tariffs on steel and aluminum from 25% to 50%. For an industry that relies on steel and other metals to build its generating plants and infrastructure, the result is obvious.

"A lot of other things we can sort of mitigate, but we use a lot of steel," Occidental Petroleum CEO Vicki Hollub said. "And so when we have a lot of steel tariffs, it can really impact our industry and our cost structure."

Hollub said her governmental and regulatory staff have been unable to provide clear answers on what to expect out of D.C.

"For the first time in my tenure as a CEO, I've heard our government guy come to our board meeting and say, 'I don't know' to more questions than [having] thoughts," she said. "We just can't forecast right now. We're trying to come up with lots of scenarios and evaluate the possibilities that, clearly, the largest impact on us would come if the steel tariff were to stay high."

"The elephant in the room is what's going on with the tariff policy," said incoming EEI CEO Drew Maloney. "Everybody you know wants to understand how that's going to impact their businesses here and how that impacts our traditional trade partners … how that's going to impact business and sort of watching to see what happens.

"As we develop this more of an America First policy, what does that mean for Europe? Is Europe going to do more manufacturing going forward? Are they going to sort of reshore their supply chain?" Maloney added, calling for global collaboration with global trading partners "because that obviously is going to impact our energy growth that we're going to have here."

Maloney was *appointed EEI's CEO* in April, replacing interim CEO Pat Vincent-Collawn, effective July 1. Vincent-Collawn, CEO of TXNM Energy and its two subsidiaries in Texas and New Mexico, *replaced Dan Brouillette* when he stepped away from the organization in 2024.

Maloney brings with him decades of legislative expertise from working on Capitol Hill and maintaining relationships with key lawmakers for various organizations. He served in the Treasury Department during the first Trump administration and as chief of staff for the House of Representatives GOP leadership.

Growing up on a farm in the Shenandoah Valley also prepared Maloney for work in D.C.

"I had to get up really early in the morning to make sure that all the animals were fed," he said. "I had to clean out the stalls — great preparation for working in Washington, because there's a lot of stall-cleaning in Washington."

Victor Peng, AI developer | © *RTO Insider*

The Benefits of AI

While the growing reliance on AI could result in data centers *consuming up to 12%* of the nation's power demands by 2028, speakers from the high-tech sector stressed the benefits of working with the technology.

Victor Peng, the recently retired president of AI developer *AMD*, said he was impressed with his audience's willingness and desire to "meet this special moment in time."

"I've heard from everyone here how collaborative this industry is, and that's critical," he said. "It's encouraging to see people committed to understanding how to support AI. Really, it's more than AI. This industry touches everyone's lives on a daily basis and in every facet. The positive thing about AI is that it will affect everything.

"You should feel comfortable that this is not a bubble. The demand is real, and it will last for a really long time. And the pace that it is expanding at is daunting."

"I think anyone who reads history understands that adaptability and harnessing new technologies is really the difference between success and failure," Oracle CEO Safra Catz said. "It is without a doubt the difference between success and failure for companies, and it truly is the difference for countries and entire civilizations. There is no question that harnessing AI is widely recognized as a technical matter and a national security matter.

"This is the moment we've all been waiting for, using data to get better information to really help you all run your business. So, this moment is very, very important, and it's going to be a challenge for a lot of folks to make the bold decisions of how do they move their technology to the 21st century. We're already 25 years into it."

Pausing for effect, Catz said, "The time is now."

New Leadership for EEI

EEI's Board of Directors *elected* Butler as chair for the 2025/26 cycle. The board also elected Womack and Evergy CEO David Campbell vice chairs. All three selections are effective July 1.

Drew Marsh, Entergy | © *RTO Insider*

Butler most recently served the institute as a vice chair. The EEI's chair rotates annually.

The three chairs appeared on stage together before the membership June 3 to share their thoughts on the coming year. Campbell, a lifelong Dallas Cowboys fan now leading a utility headquartered on the Kansas-Missouri border, wore a No. 3 Philadelphia Eagles jersey with Butler's name of it, much to the delight of Butler and Campbell.

"Many of you were coming up to me saying, 'Hey, what's up with David wearing an Eagles jersey?'" Butler said. "I said, 'I don't know. That's just David being David, and I'm flattered.'"

It became obvious who was the loser of a 2025 Super Bowl bet. As a reminder, Butler's Eagles had no trouble with Campbell's adopted Kansas City Chiefs, 40-22.

"Why number three?" Campbell said he asked Butler. "He said, 'Because that's my favorite number.'"

"But what do Eagles do? You know what you have to do," Womack said, flapping his arms and encouraging Campbell to sing the Eagles' fight song, "*Fly, Eagles Fly*."

Campbell declined. However, he did complete his losing wager with a robust and quick "E-A-G-L-E-S, Eagles!", half-heartedly punching the air with his right fist.

"This is a devastating day for me," he said.

Louisiana Gov. Ribs Entergy

As the EEI's host member, Entergy was

given the honor of conducting the conference's opening discussion, a conversation between its CEO, Drew Marsh, and Gov. Landry.

Entergy is seeking regulatory approval to build 2.4 GW of gas-fired power plants to service Meta's *massive data center* in Northeast Louisiana. It's about a $10 billion ask that also includes 100 miles of 500-kV transmission and eight 230-kV lines.

Marsh asked Landry whether the state can continue to attract large investments in the future. Given the opening, Landry responded without directly mentioning May's load shed that knocked 100,000 Entergy customers offline. (See related story *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*.)

"I mean, the question is, can y'all keep the lights on?" Landry said, drawing chuckles from the audience and a wan smile from Marsh.

Faces in the Crowd

Among the industry CEOs and regulators at the conference were former Louisiana Sen. Mary Landrieu, now a lobbyist but still exhibiting a master politician's touch with reporters; former EEI CEO Tom Kuhn, now board chair for wireless communications company Anterix; PGE's Pope chatting on the sidelines with Grid United's Michael Skelly; industry consultant and Texas regulator Bob Gee, now a board member with the *United States Energy Association*; and Archie Manning, former quarterback for the New Orleans Saints and patriarch of the family's quarterback dynasty, and his son Cooper, whose own football career was ended by a spinal condition.

The Mannings regaled their audience with their tales of Archie's life in New Orleans and raising three boys who have quarterbacked four Super Bowl winners. Cooper's son, Arch, is expected to be the NFL's top draft pick should he leave the University of Texas early next year. By all accounts, Arch is just as grounded as his father and his more celebrated uncles.

"Clearly, I had an unbelievable mentor at home," Cooper said, referring to his father. "I can't tell you the number of times I've had to ask, 'What would Dad do?'"

Archie, who was sacked 337 times during his 11-year career with the Saints (nine of which were losing seasons), told the story about being honored as one of the club's 50 greatest players. During a banquet honoring the players, Manning, recovering from knee-replacement surgery, limped to the podium to say a few words. One of his "old" offensive linemen — "who, I assure you, was not one of the 50," Manning said — offered to carry him up to the podium.

"I couldn't help it. I said, 'No, I don't want to be carried, but if you and your buddies had blocked anybody out, I wouldn't be like this,'" Manning said to laughter.

Edison International, Fortis Win Awards

Edison International and its Southern California Edison subsidiary won the 97th Edison Award for domestic companies and Canadian utility Fortis won the international Edison Award, presented annually during the conference.

Edison and SCE *were recognized* for the utility's Advanced Waveform Anomaly Recognition system, which supplements advanced sensors and other applications already in service with state-of-the-art physics-based AI models and machine-learning technologies. The technology can help to identify and locate problematic equipment on SCE's circuits before a failure occurs, mitigating outages.

Canadian electric holding company Fortis *was honored* for its Wataynikaneyap Power Transmission System project, the country's largest Indigenous-led electric initiative. Fortis partnered with Wataynikaneyap Power and 24 First Nations communities to construct an 1,118-mile transmission line connected to 22 substations. The system connects 17 rural and remote First Nations communities to the Ontario provincial energy grid.

The Edison awards are chosen by a panel of former energy industry executives. ■

EEI attendees network during a conference break. | © *RTO Insider*

New Tech Requires Innovative Regulations, WCPSC Panelists Say

Performance-based Regulation Highlighted as a Way Forward

By Henrik Nilsson

PORTLAND, Ore. — Panelists at the annual meeting of the Western Conference of Public Service Commissioners emphasized the need for innovative regulatory frameworks to keep up with new technology.

Jay Griffin, senior adviser at the Regulatory Assistance Project and former chair of the Hawaii Public Utilities Commission, said electric industry participants in the U.S. should look to their counterparts in the United Kingdom.

After having visited the U.K., Griffin said, "one of the striking things there was how much quicker the pace interconnection is for large loads and generation resources."

Griffin made the comments at a panel discussion on technology adoption rates and regulatory reform during the WCPSC session on June 2.

Griffin noted the U.K. has leveled the playing field of interconnection in part by having an open-source map that updates real-time capacity throughout the entire network and by making the pre-application connection assessment easier through a publicly available web app.

"They're bringing resources online much faster," Griffin said. "The tradeoff there is some level of curtailment over time, but that's in exchange for bringing projects online years faster."

Another key to the puzzle is that the U.K. uses performance-based regulation (PBR), according to Griffin.

PBR is a way to align utility incentives with the interests of customers and society. Traditional regulation pays utilities for what they build, while PBR focuses on what they achieve, according to a report issued last year by RMI.

Why This Matters

Regulations must keep up in order to take advantage of new technology and to tackle load growth.

Mark Thompson, Form Energy | © *RTO Insider*

PBR is still in the "nascent phases" in the U.S. — and in the Pacific Northwest, said Lauren McCloy, policy director at the Northwest Energy Coalition.

Still, the fact that PBR is being discussed as a way to address public needs and bring new technologies online is encouraging, McCloy said.

To implement PBR in the U.S., regulators should start "with a broad-based conversation about what are the policy goals that we're trying to achieve," according to McCloy.

"What are the technologies that are available to try to achieve that? And then, what are the incentive structures within cost of service-based regulation and maybe, you know, other frameworks that we could adopt to make that technology both more accessible, more transparent and deliver more benefits to customers."

However, Elliott Nethercutt, senior director of state regulatory affairs at the Edison Electric Institute, urged caution.

Nethercutt said the existing regulatory framework is designed for reliability and affordability.

"I think that we got to move faster, but we don't want to throw out the baby with the bathwater," Nethercutt said. "We just need to see how we can make things … work and move a little more efficiently."

Pilot programs, future test years, cost trackers and multiyear plans, among other alternative approaches to regulation, "can really move things faster and really meet the needs of electric companies and their customers in an era of rapid load growth," according to Nethercutt.

Risks of Inaction

In a separate panel, Michele Beck, executive director of the Utah Office of Consumer Services, similarly stated that the industry must take a cautious approach when implementing new technology and updating planning processes.

"I understand there's new times, and we need new solutions, but … the solution is not to put risk on customers," Beck said.

Beck also noted "maybe we need a pilot program" to temporarily step outside the current "least-cost, least-risk paradigm." This would allow regulators to look at cost allocations and augmentations to planning processes "to make sure that we're treating all the resource types fair," Beck added.

Meanwhile, Mark Thompson, a former Oregon utility commissioner who is now Form Energy's senior director of state affairs, said while it's a fair question to ask about the risk to ratepayers, regulators should also ask "what are the risk of not doing a new technology?"

"If the future is very different from the past, and we see all these constraints, and we have new challenges, and we have a new need for resources, there's significant risk for ratepayers of never figuring out the new technology," Thompson said. "These new technologies need a pull from the market. They need a pull from utilities who are willing to be partners, and they need a pull from regulators saying, 'we're willing to try something with you. Let's figure out what it is.'" ■

CEC Considers Opposition to Compass Battery Project in Southern California

Thousands of Letters of Concern Submitted, Some in Favor

By David Krause

California is setting records for the amount of battery energy storage operating on its grid, but in one Southern California beach county, residents have come out in large numbers opposing a proposed battery facility because of fire safety concerns.

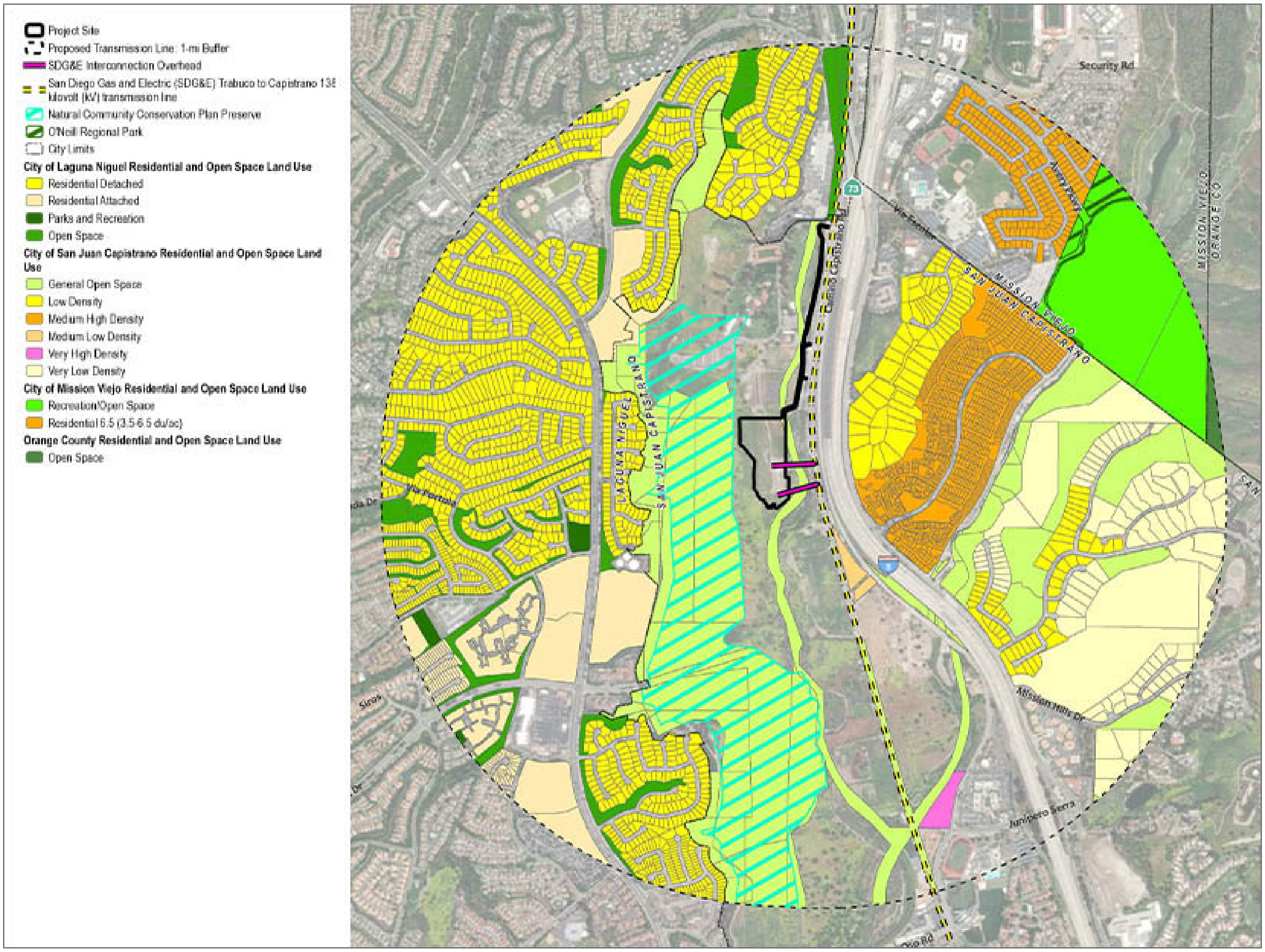
The proposed Compass Energy Storage Project would operate as a 250-MW facility in San Juan Capistrano, near Laguna Niguel and Laguna Beach. California now has more than 12,000 MW of battery storage operating on its grid.

The project is under review with the California Energy Commission, specifically the CEC's Opt-In Certification program, which began in 2022 as part of Assembly Bill 205. The program's permitting process offers "developers an optional pathway to submit project applications, facilitating faster deployment of renewable technologies," the CEC said.

Most residents and government officials in opposition are worried about a fire

Why This Matters

Batteries are becoming one of the most important energy resources in California, but since the Moss Landing battery storage fire in January, residents are voicing more concerns about battery safety.



This overhead image shows the location of the proposed project. The dotted yellow line is an existing transmission line, the purple lines are proposed interconnection lines, and the black rectangle is the project's proposed location. | *Compass Energy Storage* at the facility and the release of toxic chemicals. Laguna Niguel, for example, is located directly downwind of the project site during offshore winds, which not only occur during Santa Ana wind events but also on most nights, especially during the winter months when the inland valleys cool more than the ocean, the city said in comments filed with the CEC.

Laguna Niguel officials pointed to the Moss Landing battery storage facility that caught fire in January 2025 and required the evacuation of approximately 1,200 people within an eight-mile radius. A fire at the proposed Compass Energy Storage facility would require the evacuation of more than 37,000 people in a two-mile radius alone, the city said. An eight-mile radius could require 100,000 or more people to move out, the city said.

In response to safety concerns, Brett Fooks, CEC manager of safety and reliability, said the Moss Landing facility has two different safety characteristics compared with the proposed Compass Energy Storage project. First, the Moss Landing batteries are nickel magnesium cobalt lithium-ion batteries. This type of battery is more prone to thermal runaway than is the Compass battery, which would use a lithium-ion phosphate chemistry, Fokes said.

Second, the Moss Landing batteries are located indoors, whereas the Compass project's batteries would be located outdoors. Indoor battery facilities are less fire-safe, Fooks said.

Objective Review

Not all local parties oppose the project. The Orange County Hispanic Chamber of Commerce offered support in comments to the CEC. The permanent shutdown of the San Onofre Nuclear Generating Station, combined with San Diego Gas & Electric's forecast of a doubling in energy demand by 2045, underscores the importance of this initiative, the chamber said.

"The Compass facility will play a critical role in storing renewable energy and ensuring its availability during periods of high usage," the chamber said. "In addition to its environmental contributions, the project is expected to provide over $50 million in local tax revenues, directly benefiting public schools, infrastructure development and community safety."

The CEC currently has three projects with completed applications in its Opt-In Certification program, CEC staff told *RTO Insider*. The first project, Darden Clean Energy, has been recommended by staff for approval and will be considered by the commissioners at a business meeting June 11.

The second project, the Fountain Wind project, has been delayed beyond the 270-day timeline in alignment because of significant changes to the project discovered during development of the environmental impact report. CEC staff have recommended against the Fountain Wind project, which is anticipated to go before the commission at a business meeting in August or September, CEC staff said.

The CEC plans to vote on the Compass Energy Storage Project near January 2026.

If approved, the facility would interconnect into the existing SDG&E Trabuco-to-Capistrano 138-kV transmission line, which is about 500 feet from the project site. The project would connect to the transmission system through a "loop-in" transmission line. No downstream upgrades or off-site transmission upgrades are required for the proposed project, CEC staff said.

The CEC does not decide on the location of energy projects in California, leaving that to developers, CEC Executive Director Drew Bohan said at a May 29 public meeting.

"We evaluate projects when the [developer] applies," Bohan said. "We then make recommendations as CEC staff to the CEC … about how they should dispense with the proposal."

"I want to make clear that the CEC does not advocate for or against any proposal. Instead, we review each application objectively … on safety, environmental standards and community feedback," Bohan said. ■

FERC not in Charge of Modernizing Western Grid, Christie Says

Christie, Gov. Ritter Talk About Future of Western Interconnection at Regulator Conference

By Henrik Nilsson

Why This Matters

Christie's and Ritter's comments come as the West grapples with the development of new markets and a host of grid issues confronting other areas of the country.

PORTLAND, Ore. — In their respective speeches during the annual meeting of the Western Conference of Public Service Commissioners, outgoing FERC Chair Mark Christie and former Colorado Gov. Bill Ritter both emphasized that the West controls the future of the Western Interconnection, not Washington.

Christie addressed WCPSC participants remotely June 2, a few hours before news broke that President Donald Trump would nominate Laura Swett of Vinson & Elkins to replace Christie on FERC. (See related story, *Trump Replacing FERC Chair Christie with Laura Swett*.)

Christie said in his speech that the "early days" of FERC trying to force states and utilities to join an RTO are over.

"It's called standard market design, and I remember that, and I thought that was a horrible mistake. And fortunately, it didn't happen," Christie said.

"It's not for us at FERC to tell you what to do," he told the audience. "You got to make that choice on what's right for you."

FERC Chair Mark Christie during the annual Western Conference of Public Service Commissioners | © *RTO Insider*

The chair said if the West decides to create an RTO, the industry should think of it "as a bundle of services," functioning mainly as a grid operator.

An RTO is "not one single service. … I liken it to going through a cafeteria," he said. "You can pick what you want and not pick what you don't want."

Christie's comments come as many in the power industry in the West are deciding whether to join day-ahead markets offered by either SPP or CAISO.

"You've had the choice for years to go into CAISO's energy market, the [Western Energy Imbalance Market], without even joining … the CAISO itself. So, you can even pick the market without the RTO, but you've got a choice of a real-time energy market," Christie said. "You've got a choice of a day-ahead market now; CAISO has it; SPP offers it."

Christie also heaped praise on the Western Power Pool's Western Resource Adequacy Program (WRAP), saying, "I think the concept is great." (See related story *Industry Needs 'New Planning Paradigm,' BPA Chief Tells Regulators*.)

SPP operates WRAP, and the program will provide a mandatory RA framework for participants in Markets+ in an effort to ensure that members with a surplus generating capacity assist those with a deficit.

"Resource adequacy is a challenge everywhere," Christie said. "And we've seen with the data center explosion … load forecasts that are just mind-boggling."

In a similar vein, Ritter, founder of Colorado State University's Center for the New Energy Economy, noted the energy industry is grappling with significant change, both politically and technologically.

For example, artificial intelligence will impact technologies that provide power to the grid, but also power demand on the grid, Ritter said during his WCPSC address June 4.

Another change is shifting views on the energy transition, Ritter noted. He pointed to the One Big Beautiful Bill Act that recently passed in the House of Representatives. The bill would extend tax cuts for individuals and render energy tax credits effectively useless. The proposed legislation is a sharp departure from the Inflation Reduction Act of 2022, passed by Democrats, which expanded clean energy tax credits. (See *House Passes Reconciliation Package that Would End Energy Tax Credits*.)

Long-term planning and near-term decision-making become difficult when "the politics of the moment can shift on a dime," Ritter said.

However, the West still exercises control over how it chooses to modernize its grid, whether it's through RTOs or day-ahead markets, but that requires bipartisan discussions over state lines, according to Ritter.

"We need to talk across political boundaries, within states, in order to solve this issue about how we should build out transmission of the West and what that should look like as we go forward, as we look at the things that are going to change," Ritter said.

"It's going to be difficult, but if we don't do it, we're going to wind up a little bit like Washington, D.C., sounds right now," Ritter said. "A fairly toxic place — difficult to operate." ■

Industry Needs 'New Planning Paradigm,' BPA Chief Tells Regulators

Hairston's Speech to Western Commissioners Points to Looming Impact of Load Growth

By Robert Mullin

BPA Administrator John Hairston delivers a keynote address to the Western Conference of Public Service Commissioners in Portland, Ore., on June 2. | © *RTO Insider*

PORTLAND, Ore. — Bonneville Power Administration CEO John Hairston's keynote at the annual meeting of the Western Conference of Public Service Commissioners spotlighted a theme that would dominate discussion at the event: the looming prospect of overwhelming growth in electricity demand in the West and across the U.S.

Hairston's core message: Utility planning practices must change to deal with what's on the horizon.

"Current grid practices were designed for low growth that was more predictable and gradual, but I think you all understand that those days are over today," he told the audience of Western regulators and power industry stakeholders.

Hairston said transmission providers have been "flooded" with interconnection requests that would require developing new infrastructure to serve "power-hungry" data centers or connect new generators to the grid.

Requests for new service in BPA's territory exceed the entire Northwest's current peak load, he said.

"In BPA's experience, our processes have been overwhelmed by transmission service requests or duplicative and speculative projects," he said. "The reality is, it is not easy to plan for transmission grid advancement around prospective data centers or generators that may never come to fruition, and the volumes that we're seeing is just simply too big for our models to handle."

Why This Matters

BPA chief John Hairston's speech to the Western Conference of Public Service Commissioners offers yet another account of the challenges transmission service providers will face in responding to unprecedented load growth.

Hairston said the agency sees the need for a "new planning paradigm" and is "rethinking" its transmission planning processes and working with its utility customers to identify new approaches by the end of the year.

"BPA understands that time is of the essence. We have an ambitious timeline for establishing transmission planning reforms. It's my expectation that by November, we will have developed a solution that will allow us to move ahead with studying requests in our current transmission service queue. That's all 65,000 MW of that," he said.

Hairston also pointed to a key challenge the agency — and the industry in general — faces in addressing interconnection queues: a shortage of staff to do the work.

In BPA's case, staffing issues were exacerbated by the Trump administration's actions earlier in 2025 to reduce the size of the federal workforce, which resulted in many agency employees taking "deferred resignation" buyout packages. (See *BPA to Restore 89 'Probationary' Staff, Agency Confirms*.)

"At Bonneville, our critical functions are being met, and the lights will continue to stay on, but with fewer resources, there will be impacts, and workforce needs could potentially slow our progress toward greater expansion," Hairston said.

The issue has been compounded by a federal hiring freeze, but Hairston said he's "hopeful" about the agency's "prospect of regaining our hiring authorities."

"The Department of Energy recognizes the vital role that BPA plays in supporting our nation's grid and is committed to ensuring that we have the staffing that we need to execute on our mission," he said.

'Collaboration was Key'

Hairston's speech notably omitted mention of a subject that's consumed the attention of many Western stakeholders for the past two years: BPA's much-awaited decision in May to join SPP's Markets+ rather than CAISO's Extended Day-Ahead Market. (See *BPA Chooses Markets+ over EDAM*.)

Critics of that decision contend it will prevent the Western Interconnection from developing the kind of single electricity market necessary to take full advantage of the region's resource and load diversity, thereby maximizing the use of non-emitting renewable resources. The "seams" between Markets+ and EDAM will impede the coordination required to do that, they argue. (See *Debate Lingers After BPA Day-ahead Market Decision*.)

Throughout BPA's day-ahead decision-making process, BPA staff have expressed confidence in the ability of the agency — and SPP — to manage energy transfers across seams based on its own history of doing so within the Northwest.

Hairston's speech appeared to pick up on that line of thinking, if obliquely.

"On paper," he said, the Western Interconnection might look fragmented to many, divided into multiple balancing areas "that operate and plan for the future of the grid independently."

"But that doesn't mean that we work in silos," he said. "We understand that reliability and efficient operations require a lot of coordination. In fact, if you look back over the history of the Western Interconnection, it's safe to say that collaboration was key to almost every major advancement that we've had."

Hairston also pointed to historical efforts to share resources across the West, including development of what now is known as the Western Power Pool, which in recent years has led development of the Western Resource Adequacy Program (WRAP), which will provide a mandatory RA framework for participants in Markets+.

"Essentially, the program addresses the segmentation in the region where multiple utilities could be counting on the same power during the same time, which may not be available in the market," he said. "Now, with all members using the same resource planning methods, WRAP provides greater assurance of maintaining region-wide reliability."

Without naming the market, Hairston's speech appeared to refer to one of the key challenges facing Markets+: the lack of transmission connecting its non-contiguous footprint, spread across discrete pockets in the Northwest, Desert Southwest and Colorado.

In speaking about BPA's proposed inter-regional transmission projects, he called out plans for a possible line that would run from Central Oregon to the Nevada-Oregon border, "opening an opportunity for a southern partner to take it from that point, enabling energy transfers between the Pacific Northwest and the Desert Southwest."

"And while I'm encouraged and hopeful about our prospects, I'm clear-eyed about the obstacles that we face. Among them is the challenge of making significant infrastructure investments while preserving affordability," he said. ■

ERCOT: Agreement Reached to Use Mobile Generators

Resources Will Address Reliability Concerns in San Antonio

ERCOT has told Texas regulators it's completed its contractual work with LifeCycle Power, CenterPoint Energy and CPS Energy, clearing the way for 15 mobile generators to be moved from Houston to San Antonio and to provide more capacity in the area.

ERCOT General Counsel Chad Seely said at the Public Utility Commission's June 5 open meeting that the first wave of generators is expected to arrive in the San Antonio area in July.

The mobile units, each capable of providing about 30 MW of power in about 10 minutes, will be interconnected to CPS substations in the city. Eight of the nine substations that will house the units are ready for delivery.

"I know LifeCycle has committed to move as quickly as possible," Seely said. "A tremendous amount of work by everyone to get this across the finish line."

ERCOT says the generators are necessary to mitigate emergency load-shed that may be necessary to avoid overloads of a generic transmission constraint. Staff have been working on the agreement since February 2025, when it became apparent they 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*.)

The grid operator earlier entered into an RMR contract with CPS for V.H. Braunig Unit 3, its first. The San Antonio municipality said in 2024 that it was planning to retire all three Braunig units in March 2025. ERCOT said the plant's retirement would lead to reliability issues until the transmission constraint is resolved. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

Under the *agreement*, ERCOT will be able to dispatch the units only during actual or expected emergency conditions. The costs (an estimated $51 million) will be uplifted to qualified scheduling entities representing load on an hourly load-ratio share basis.

The units are leased from LifeCycle by CenterPoint. The Houston utility made them available to ERCOT, without compensation, through March 2027.

ERCOT's Chad Seely briefs the PUC on the ISO's agreement with LifeCycle Power to move mobile generators to San Antonio. | *Admin Monitor*

ISO Gets Good-cause Exception

The PUC granted ERCOT a good-cause exception for the 2025 Regional Transmission Plan, allowing the grid operator to adjust load forecasts outside the protocols' requirements.

Recent *state legislation* requires the grid operator to include any load in its projections that doesn't yet have a signed interconnection agreement. The ISO's staff have proposed a 49.8% reduction in data center loads and a 55.4% cut in these "substantiated loads," which are support by an executed interconnection agreement, a credible third-party forecast, or attestation by a transmission and distribution service provider (*55999*).

The reductions bring the forecasts more in line with historical performance, ERCOT *said*.

The PUC declined ERCOT's request during its May 15 meeting, asking staff to provide additional information. (See *ERCOT, PUC Refining Future Load Projections*.)

CenterPoint to Securitize $396M

In other actions, the PUC:

- *Approved* CenterPoint's request to securitize $396 million of system restoration costs from two storms in May 2024. The commissioners agreed with Chair Thomas Gleeson's proposal to adopt a standard of negligence instead of gross negligence (*57559*).
- Adopted a *rule* that sets reporting requirements for transmission providers and establishes monitoring responsibilities as part of the plan to build 765-kV import paths into the petroleum-rich Permian Basin. The monitor will identify the schedule and cost components that may affect the project's timely development and approval of necessary service requirements, while also shedding transparency of expenses. The transmission providers will bear the monitor's costs (*57602*). (See *Texas PUC Approves 765-kV Transmission Option for Permian Basin*.) ■

— Tom Kleckner

ERCOT's TAC Extends Duration of Ancillary Services

By Tom Kleckner

ERCOT stakeholders have advanced a protocol change that provides longer-duration ancillary services and state-of-charge (SOC) parameters in advance of real-time co-optimization's deployment in December.

The ERCOT-sponsored protocol change (*NPRR1282*) updates duration requirements to 30 minutes for regulation service and responsive reserve service and one hour for ERCOT contingency reserve service (ECRS). It also revises reliability unit commitment studies' requirement to a one-hour duration for all ancillary services, excluding fast frequency response.

Staff told Technical Advisory Committee members that longer-duration AS are needed to manage grid variability and uncertainty. The grid operator, the Independent Market Monitor and stakeholders were split on the appropriate duration for non-spin and ECRS.

Several renewable interests *said* ERCOT's RTC dispatch or SOC enforcement requirements will be "unnecessarily and administratively restrictive" of the amount of megawatts energy storage resources can offer.

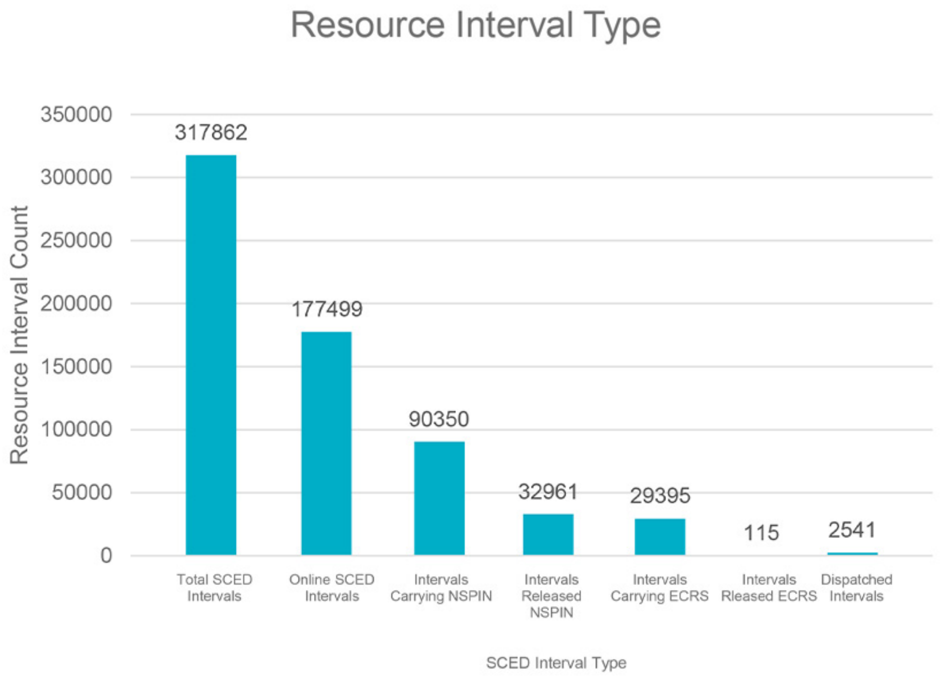
The IMM recommended setting the non-spin duration constraint to one hour instead of four, saying that would incent batteries to provide energy rather than reserves. It said the four-hour duration also would deplete batteries' SOC.

"The operations posture we have is the operations posture we have," said Nitika Mago, senior manager of balancing operations planning. "As things evolve, I've conceded again and again we are happy to revisit it. But today, with the way we operate the grid and with the type of risks we see for non-spin, a four-hour duration is appropriate."

In the end, Mago's commitment to review information generated during RTC's market trials, which begin in July, and an analysis of duration in the 2027 AS methodology document won over many stakeholders with concerns.

A motion to approve the NPRR with *comments filed* by ENGIE and Jupiter Power, and its associated Nodal Operating Guide change (*NOGRR277*), failed 11-18. When the comments were removed, the measure passed 26-2, with one abstention. ENGIE and Jupiter Power cast the dissenting votes.

The NPRR was granted urgent status so its parameters can be installed for RTC's market trials.



Pilot participation stats for ERCOT's Aggregated Distributed Energy Resources pilot project | *ERCOT*

Members Table Curtailment Change

TAC's members unanimously agreed to table *NPRR1238* and *NOGRR265* after a lengthy discussion on their merits. The changes introduce a new early curtailment load (ECL) category and also would establish a process allowing loads to operate as an ECL so they can be accounted for differently in load-shed tables.

The committee will take up the issue again during a special webinar *June 12*.

ERCOT legal staff recommended tabling the two measures pending the Texas Legislature's final consideration of *Senate Bill 6*. The legislation, addressing large loads, was under consideration before the session's expiration June 2; several parties agreed with the need to align with the legislative process. (See *Growing Clean Energy Sector in Texas May Avoid Damaging Legislation*.)

Staff said the grid operator generally supported the NPRR but said they had concerns over large-load curtailments before energy emergency alerts.

Stakeholders expressed concerns with mandating loads — primarily industrial — to register as curtailable. NPRR1238 is intended to cover flexible loads sensitive to high prices, not all large loads.

The Public Utility Commission's Barksdale English agreed with the decision to table the changes, saying it would be "smart" after amendments had been added two days before.

Oncor $855M Project Endorsed

TAC endorsed staff's recommendation to award Oncor Electric Delivery a $855.3 million project in West Texas by placing it on the combination ballot, which acts as a consent agenda.

Oncor submitted the proposed Delaware Basin Stage 5 project for the Regional Planning Group's review in May 2024. Wind Energy Transmission Texas (WETT) submitted an alternative project in August 2024.

Staff said Oncor's proposal addresses reliability concerns and accommodates "significant and rapid load growth" in the petroleum-rich Delaware Basin area and also was less costly and required the fewest transmission lines requiring regulatory approval. Oncor's project requires 220 miles of transmission approval, while WETT's costlier proposal ($871 million) is 232 miles long.

The project was identified in a *2019 ERCOT study* that found the need for an import path to serve load once the Basin's peak demand is greater than 5,422 MW. Staff said the *2023 Regional Transmission Plan's* 2025 case exceeds that level.

The project is expected to be in service by December 2029.

Committee members also confirmed Longhorn Power's Bob Wittmeyer and ERCOT's Patrick Gravois as chair and vice chair, respectively, of the Large Load Working Group by adding the recommendation to the combo ballot. The group, which recently removed "Flexible" from its title, has scheduled a workshop *July 11* for data centers and electronic loads, with a focus on behind-the-meter systems that can survive low voltage and stay on the grid or resolve low-voltage issues.

Outage Capacity Changes

Stakeholders unanimously approved *staff's revisions* to the methodology used to calculate the maximum daily resource planned outage capacity (MDRPOC).

The revisions are intended to provide sufficient outage capacity compared to historical levels by applying a risk-based construct for outages more than seven days ahead. Staff created a new MDRPOC curve to better evaluate thermal resources, and they have incorporated minimum outage levels in winter and summer to spread outages throughout the year.

ERCOT plans to apply the first future year MDRPOC to subsequent future years, saying there is a higher risk of limited resource commitments and project load growth in later years. Renewable resources and storage units will have their MDROPC calculated based on 110% of the historical maximum planned outages from the previous three years.

The measure passed 17-0, with 10 abstentions. The independent generators, power marketers and retail segments each provided three abstentions.

ERCOT is *accepting comments* on its proposal through June 9. It will go before the board during its June 23-24 meeting.

TAC Endorses ADER Doc

TAC endorsed a governing document for the third phase of ERCOT's Aggregated Distributed Energy Resources (ADER) pilot project by adding it to the combo ballot.

Staff proposed increasing participation limits to 160 MW for energy and 80 MW for non-spin reserve service and ECRS, respectively. Phase 3 will allow a new participation model similar to non-controllable load resource (NCLR) and will enable third-party qualified scheduling entity (QSE) aggregation under the NCLR model, regardless of load-serving entity affiliation.

The grid operator will continue to analyze ADERs' effect on system reliability and market efficiency, focusing on shift factor discrepancies and telemetry validation improvements.

ERCOT said that as of May, three ADERs have been qualified. They offer 15.5 MW capability for energy, with 8.6 MW for non-spin and 8.8 MW for ECRS. Nine additional ADERs are in various stages of registration, it said.

The pilot began in July 2022 and recently transitioned to ERCOT. (See "ADER Discussion Moved to WMS," *ERCOT TAC Opens Discussion on Proposed RTC Changes*.)

The combo ballot also included the strategic objectives for the Retail Market and Wholesale Market subcommittees, three other NPRRs, one NOGRR, a single change to the Planning Guide (PGRR) and an Other Binding Document (OBDRR) that, with required board approval, will:

- *NPRR1226*: Direct ERCOT to prepare and publish estimated demand response data showing aggregated state estimated load points selected by ERCOT. Loads selected for the report will be based on periodically updated off-line analysis of the frequency and magnitude of reductions observed in historical state estimator load data that is associated with LMPs, ERCOT-wide conservation appeals or other market signals.
- *NPRR1267*: Require a large-load interconnection status report be published. The report won't define "large load," leaving that to *NPRR1234* (Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater). Confidential customer information on large loads will be aggregated.
- *NPRR1276*: Incorporate an OBD, "*Emergency Response Service Procurement Methodology*", into the protocols to standardize the approval process.
- *NOGRR275*: Align the guide with protocol changes to eliminate scheduling center requirements for QSEs that are not wide-area network participants.
- *OBDRR054*: Create a process by which transmission and/or distribution service providers will require market participants to successfully test retail transactions before their data universal numbering system is activated in a TDSP's production system.
- *PGRR125*: Add language to that guide that allows an interconnecting entity or property owner to demonstrate compliance under the Lone Star Infrastructure Protection Act should it have a subsidiary or affiliate that falls under the act's citizenship or headquarters criteria. The subsidiary must not have direct or remote access to or control of the project, the project's real property, resource integration and ongoing operations, the market information system, other ERCOT systems or any confidential data from the systems. ■

Northeast news from our other channels

Rural Town Grapples with N.Y.'s Renewable Energy Vision

NetZero Insider

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

Operating Reserve Prices Surge in Ontario

By Rich Heidorn Jr.

The opening of Ontario's new market has been marked by real-time volatility and unusually high operating reserve (OR) prices.

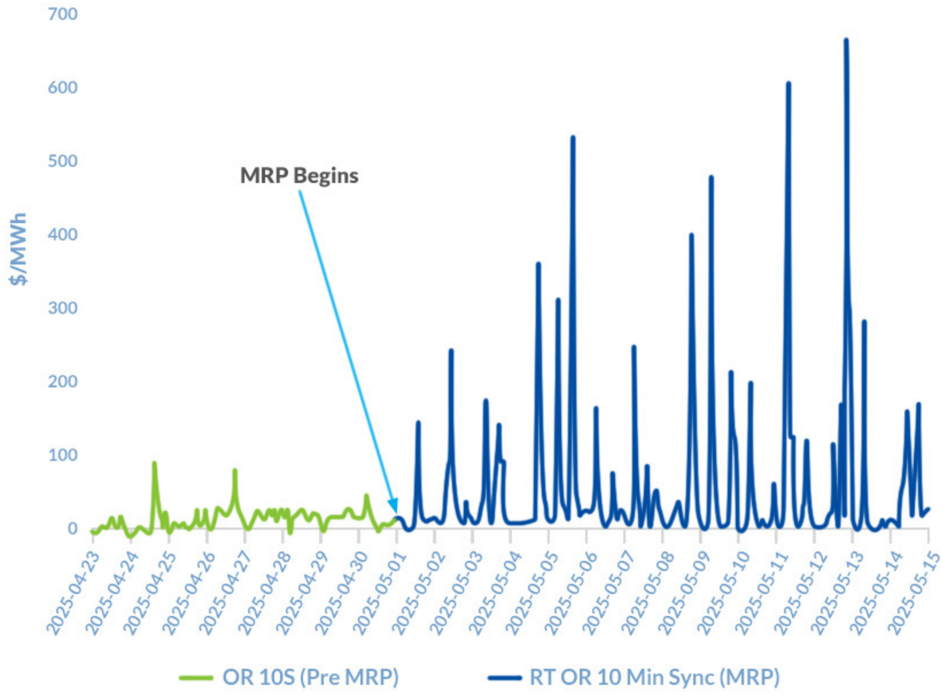
"They seem to be burning through their ancillary service reserves," said former trader Jake Landis, director of solutions engineering for Yes Energy. "[It's] almost as if they aren't carrying enough reserves in general."

"100%," agreed Brady Yauch, director of markets and regulatory for Power Advisory. "The ancillary services market is just really tight right now … although energy we're very long."

Between 2021 and 2024, Yauch said, 10-minute spinning reserve (10S) prices in the first two weeks of May ranged from $6 (2024) to $19/MW (2022). In the first two weeks of May 2025, the average day-ahead price has been $30/MW, with real-time prices averaging $51/MW. "So there's a huge difference," Yauch said.

At an IESO webinar June 4, Yauch asked whether the higher OR prices were a short-term phenomenon or indicative of a structural change as a result of Ontario's Market Renewal Program, which implemented a financially binding day-ahead market and switched from zonal to nodal pricing on May 1. (See *IESO Opens Day-ahead Market in Nodal Rollout*.)

Darren Matsugu, director of markets, responded that the OR price trend was



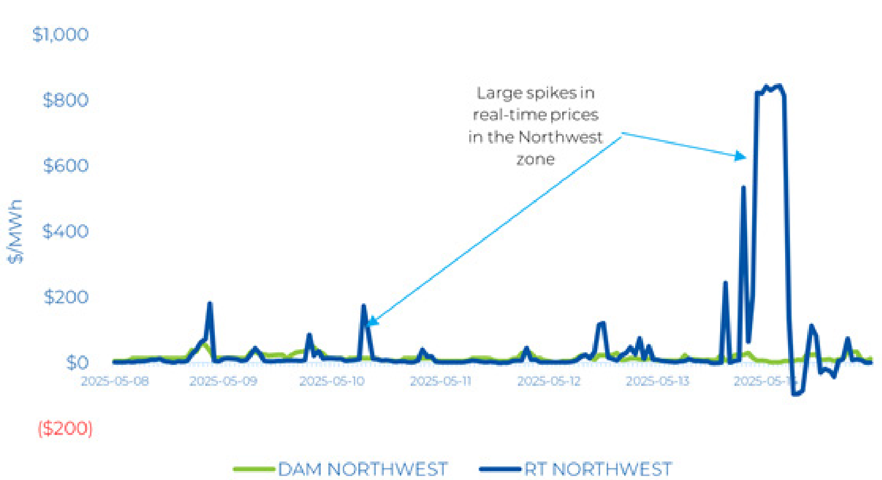
IESO real-time operating reserve prices before and after the launch of the Market Renewal Program (MRP), which introduced nodal pricing and a financially binding day-ahead market | *Power Advisory*

a springtime issue, citing "freshet," the annual influx of water from spring rainfall and melting snow. Many hydropower projects must exit the OR market and operate as "must run" generators in spring because they have to flow the excess water through their turbines.

"It happens every May — this year, even more than perhaps other years — the amount of reserve available from those

Why This Matters

Market observers are watching to see if IESO's nodal market provides the efficiencies and savings promised by ISO officials.



Northwest Ontario has seen big spikes in real-time prices since IESO introduced nodal pricing May 1. | *Power Advisory*

hydroelectric resources is less than normal," Matsugu said.

At the same time, natural gas generators are less likely to be committed and online during times of low demand. "And so naturally, that puts a scarcity in the amount of operating reserves that we have available on the system under these types of conditions," he added. "As we get further into the summer, both as far as the hydrology — but also we have more other resources committed and online that can provide operating reserve — we expect that to stabilize."

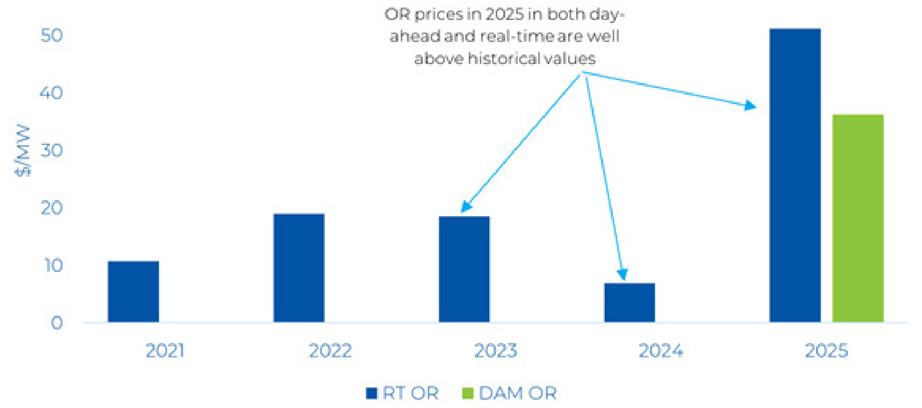
Yauch acknowledged that thin OR supplies are typical in the spring shoulder period. But he said OR prices this May appear to be impacted by a change in the supply stack, with the introduction of an operating reserve demand curve. In the legacy market, IESO used a voltage-reduction offer in the OR supply stack — what Yauch called "fictitious supply."

"Ultimately, the supply and demand on the system create the pricing outcomes observed, including over the last month," IESO spokesperson Andrew Dow said in an email to *RTO Insider.* "Market Renewal delivered many improvements to how energy and OR co-optimization produce prices in the market, including but not limited to introducing an OR demand curve. All of these improvements work together to create better alignment between the pricing outcomes and the underlying system conditions and resource availability."

IESO says the MRP should save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency.

NERC and the Northeast Power Coordinating Council require IESO to provide OR equal to the largest single contingency plus half of the second-largest contingency — equivalent to the loss of Ontario's one-and-a-half-largest generators.

IESO purchases three types of operating reserves from dispatchable generators and loads: 10-minute synchronized (spinning); 10-minute non-synchronized (non-spinning); and 30-minute non-synchronized. OR providers must be able to respond within the 10- or 30-minute time frame and provide energy for up to one hour.



Between 2021 and 2024, 10-minute spinning reserve prices in the first two weeks of May ranged from $6/MW to $19/MW in Ontario, well below prices for the first two weeks of May 2025. | *Power Advisory*

LMPs

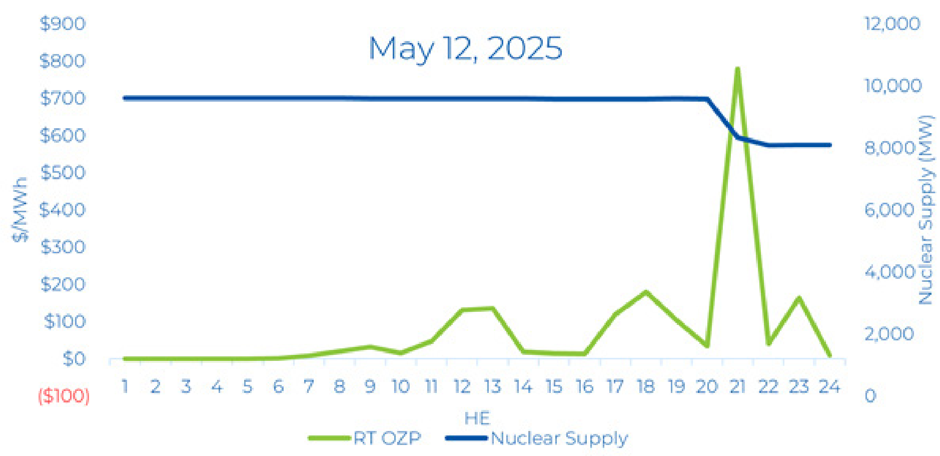
Yauch said the increase in OR prices was the biggest surprise so far from the new market. He said he was not surprised by the volatility of real-time energy prices in the first weeks.

The real-time hourly Ontario Zonal Price (OZP) — the load-weighted average of all LMPs in Ontario — rose above $100/MWh almost every day in the early weeks, "which is well above the marginal cost of a typical thermal resource in Ontario," Power Advisory said in a note to clients May 16. "In total, there were 19 hours where the price was greater than $100/MWh last week, compared to eight in the first week in May and zero hours in the equivalent week in 2024, when the uniform price was still determined by the Hourly Ontario Energy Price (HOEP)."

Day-ahead zonal prices averaged $19/MWh for the second week, versus a real-time average of $38/MWh, Power Advisory said. The Northeast and Northwest zones saw much higher congestion and transmission losses than southern Ontario, as was expected, it said.

Yauch called it a "tale of two grids," with southern Ontario experiencing limited congestion and the north choked by a large number of hydropower facilities and dwindling mining and industrial loads to absorb the supply. "They can't get the energy out," he said.

The first two weeks also saw a lot of volatility in the west near Windsor. "That was a surprise, but it's died down," Yauch said.



A derate to the Bruce Nuclear Generating Station on May 12 caused real-time prices in southern Ontario hit the price ceiling of $2,000/MWh, with the Ontario Zonal Price rising to $778/MWh in the 8-9 p.m. hour. | *Power Advisory*

Nuclear Impact

Hydropower isn't the only generation source impacting Ontario's market. The province also has more than 12,000 MW of baseload nuclear capacity. Combined, nuclear (53%) and hydropower (25%) constitute more than three-quarters of IESO's fuel mix, up from 66% in 2003.

On May 12, three units at the Bruce Nuclear Generating Station were de-rated beginning in the 8-9 p.m. hour, causing real-time prices in southern Ontario to hit the price ceiling of $2,000/MWh, with the real-time OZP rising to $778/MWh. ■

[Editor's note: *RTO Insider* became part of Yes Energy in March 2025.]

IESO Sticking with Local Generation Program Design

By Michael Brooks

IESO politely said "no" to many of the stakeholder-requested changes to the design of its proposed Local Generation Program, but noted it will include the raised concerns in its report to the Ontario government in July and signaled it was open to further discussing others before then.

The program is intended to maintain existing distributed energy resources whose contracts are expiring in the next five years and procure new facilities. However, several groups of stakeholders asked the ISO to consider changes to elements of the program before it submits its official recommendations to the minister of energy and electrification. (See *Suppliers Call for Changes to IESO Local Generation Proposal*.)

In a webinar June 5, IESO programs strategist Greg Bonser *explained* the ISO's rationale for the program's contract length, project size cap and competitive pricing.

Cooperatives and generators, among others, had requested a longer contract term than IESO's five years for facilities renewing their contracts. While new facilities would be offered longer contracts, and the ISO is considering different terms for resources that need upgrades, "we have found that under our *Medium-Term RFP*, we recently offered a term for re-contracting for five years, and it worked quite well to re-contract larger, existing facilities that are connected to the transmission system, so we're going to replicate that," Bonser said.

Some stakeholders had also asked for generators over the proposed maximum of 10 MW to be included in the program; others asked for those under the minimum of 100 kW.

Bonser said IESO is firmly against raising the size cap.

"Under the current practices and regulations and whatnot, once you go over 10 MW, there's a whole new set of rules that need to be followed around connection assessments and around the way in which our control room tries to manage those facilities," he said. He noted there were other ways for participating in the ISO's markets — a note he made several times throughout his presentation when talking about facilities not eligible for the program.

The ISO, however, is considering lowering the threshold for program participation.

"We're open to having a discussion about what kind of value those facilities can bring and whether or not they're a good fit for this program," Bonser said. "We heard a lot of small facilities say they felt they might not be cost competitive, so we need to have a conversation with" them.

Not up for consideration is including facilities under 10 kW, he said. "We also do have to draw a line somewhere."

That goes for standard offer pricing as well. Bonser called it "quite a costly and difficult thing to figure out, frankly. It's hard to keep everybody happy, and it ends up being costly to the ratepayer. We take the position that the facility owners are best positioned to review their own systems, figure out the costs and tell us what you need to keep the facility running, or what you need to build a new facility."

Why This Matters

Several groups of stakeholders asked IESO to consider changes to elements of the program before it submits its official recommendations to Ontario's minister of energy and electrification.

'Spirit of Simplicity'

About 220 people attended the webinar. There were several questions seeking clarification about the re-contracting and new-build "streams," specifically about how different fuel types will be treated in each.

IESO said existing facilities of the same type would be grouped together in the bidding process, which prompted some attendees to question whether the ISO was going against its fuel-agonistic policy. Bonser said the reason for this was to "provide continuity, and they can continue to generate after their contracts expire."

When asked if this was "definitive," Jonathan Scratch, IESO senior manager of market and system adequacy, chimed in to say the ISO was only presenting what it will recommend to the minister. He also emphasized that the fuel type grouping would only apply to the re-contracting process; new resources would all bid against each other, regardless of fuel type.

The new-build stream would begin six months after the re-contracting process began, but IESO officials declined to comment on when that would be. The program is expected to begin in 2026.

IESO is requesting more information from stakeholders or will seek guidance from the government on several requests, including:

- how to integrate DER aggregations into the program in an "administratively simple" way;
- how to allow behind-the-meter facilities to participate in the program;
- whether municipal council resolutions or indigenous support should be required for participation;
- how cooperative or indigenous ownership should be considered; and
- how refurbishments, upgrades, expansions or repowering should be accommodated.

Officials repeatedly stressed that "simplicity" in the program is a high priority for the ISO. Eric Muller, the Canadian Renewable Energy Association's director for Ontario, noted that the Medium-Term RFP "did not include rated criteria points and other policy considerations or land-use considerations or partnership factors. … It was a simple, straightforward competition on price. … I would just put forward that, in the spirit of simplicity, something similar be considered for re-contracting under this program."

Written feedback from the webinar is due June 19. ■

Ontario Nodal Market Operating as Expected at 1-month Mark

By Rich Heidorn Jr.

Ontario's nodal market is showing promise one month after its launch, with improved price certainty, increased day-ahead trading and LMPs reflecting expected congestion patterns, IESO officials say.

IESO's *Market Renewal Program* (MRP) is designed to improve the way the grid operator supplies, schedules and prices power by creating a financially binding day-ahead market (DAM) and adding about 1,000 LMP nodes. The ISO says the nodal market, which launched May 1, should save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency. (See *IESO Nodal Market Launch Successful*.)

In a briefing June 4, IESO said the initial month of operations were "consistent" with the MRP's goals. The only glitches to date were a day-ahead market failure May 22 and a delayed opening to the new virtual market.

While day-ahead prices were not financially binding in the prior market — meaning all settlements were against real-time prices — about 95% of energy volume is now clearing in the DAM. Most non-quick-start generator commitments are being made in the day-ahead rather than in real time, and pre-dispatch reviews are selecting least-cost resources.

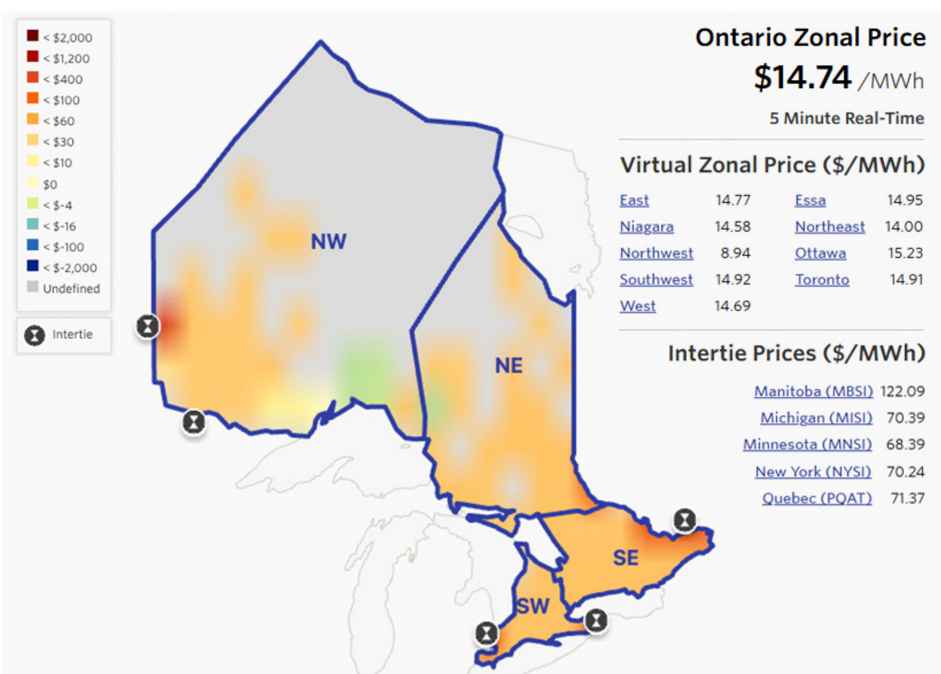
'Encouraging' Results

"The results that we're seeing from the first couple of weeks are actually really encouraging," said Darren Matsugu, director of markets. "Our locational prices really have aligned with the expectations that we've seen historically based upon congestion across different parts of the province.

Darren Matsugu, IESO | *IESO*

"With the introduction of the day-ahead market … we are seeing improved real-time certainty, both from participants and importantly for the ISO."

Most export transactions are now being scheduled day-ahead, up from virtually none in the old market. The shift "really gives the ISO a much more complete picture about the next day's operation than we used to see," Matsugu said.



Real-time prices on June 4 at 4:20 p.m. | *IESO*

Why This Matters

IESO's nodal market should save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency.

While the real-time market has shown more volatility than day-ahead prices because of unanticipated outages and supply/demand changes, those spikes are muted in consumer prices because only 5% of energy volume is settled in real time.

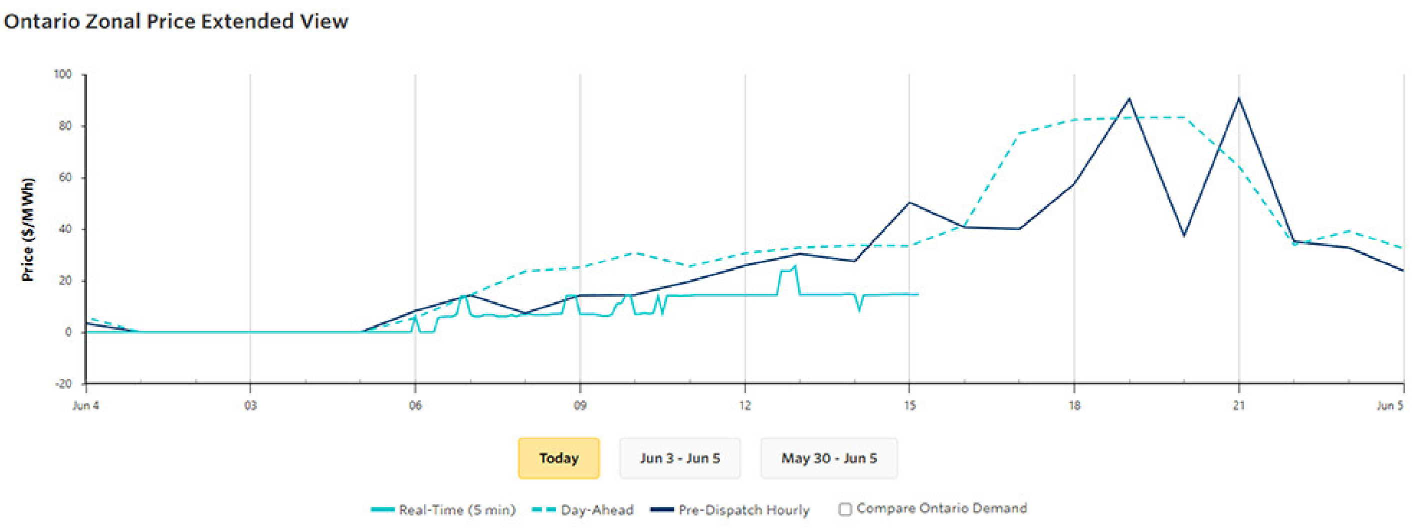
"We're seeing really complete participation and competitive participation [in the day-ahead market], which has given us good confidence in those day-ahead market results," Matsugu said. "And of course, if there's any additional scheduling needed in between day-ahead and real-time, we are seeing that this vastly improved pre-dispatch sequence is doing a good job of selecting the least-cost resources."

A Small Snapshot

Officials cautioned that their ability to draw conclusions is limited because of the short time the market has been operating. Participants are still learning about the market and developing their trading strategies, they said.

"A full year, covering all four seasons, will provide more complete information," IESO *said*.

"Market performance really does need to be considered under a wide variety … of system conditions," Matsugu said. "Every season, every month, presents itself with very material differences in terms of demand, supply conditions, transmission [and] outages. All those things are very different, and the market needs to perform very different optimization through the year. So, for example, performance during the summer and winter peak days, there's quite significant differences in system peaks and that kind of transition



IESO day-ahead, real-time and pre-dispatch prices | *IESO*

from overnight periods. And those really are kind of our best test of the market's ability to be able to efficiently maintain reliability."

'Defects' Corrected

Candice Trickey, IESO | *IESO*

The transition to the new market "went very smoothly thanks in no small part [to] the efforts of many of you out there," said Candice Trickey, director of MRP readiness.

She singled out the MRP Implementation Working Group, composed of representatives from different market sectors that helped the ISO design training and testing of the new market.

The first run of the DAM calculation engine was successful on May 2, and the first market settlement statements were issued May 15.

"Since the transition, the settlement statements have been issued on time, and there have only been a small number of disagreements that we've seen by a limited number of participants," she added. "To date, anyway, we haven't seen any widespread calculation or settlement errors."

Although the ISO's support teams saw a large jump in the number of contacts and tickets in the first week, "those have fairly quickly petered out to more normal volumes," she said.

IESO identified some "defects" during and after the launch. "Not a surprise, once you put everything into production; new things pop up, and we did identify some defects," Trickey said. "Those have all been quite quickly addressed through either workarounds or permanent fixes. Most of those things were fixed before any of you saw them.

"This was a very complex project [involving] more than 10 different systems that we had to integrate together," she added. "They all ran 24/7, providing a continuous stream of results and instructions and reports. So, it's no surprise that we experienced a few hiccups."

Timothée Denis of Air Liquide said his company's day-ahead trading limit — 50 MW before the transition — was initially limited to 25 MW at the new market's launch. "So we had to bid on half of our capacity and liquidate the rest of that on the real-time market," he said, adding that the problem was resolved May 22.

Virtual Market Delayed

Trickey also said there were some problems completing authorizations for virtual traders, which delayed the launch of the virtual market from May 8 to May 13.

The new system allows market participants to submit hourly bids and offers in any of nine virtual transaction zones.

A defect related to virtual trades caused IESO to declare a day-ahead market failure for the May 22 trade date, causing it to use real-time prices.

The ISO halted virtual trading to avoid further DAM failures until a fix was implemented, with virtual trading resuming May 24.

"Since then, we haven't experienced any other issues, but it is early days, and we still remain on high alert, monitoring and watching to see if anything else should arise," Trickey said. ■

New England Regulators Weigh Short-term Costs and Long-term Savings

By Jon Lamson

FALMOUTH, Mass. — Knee-jerk reactions to backlash over high winter costs could create long-term consequences for customers, utility regulators warned at the New England Energy Conference and Exposition on June 5.

The spike in energy costs across the region last winter, largely driven by cold weather and high supply prices, has caused significant public pressure targeted at state utility regulators, spurring debates about programs that increase costs in the near term but are intended to provide long-term savings and decarbonization. (See *Regulators Focus on Energy Affordability at NECPUC Symposium*.)

"Balancing the short term and long term is going to become increasingly difficult for PUCs," said Marissa Gillett, chair of the Connecticut Public Utilities Regulatory Authority, adding that it is important not to "throw out the baby with the bathwater in the search for the silver bullet in the short term."

On June 3, the Connecticut Legislature passed a compromise *energy bill* intended to lower bills over the next few years, reducing some incentives for clean energy and authorizing the use of rate-reduction bonds to cover storm costs and the installation of advanced metering infrastructure (AMI). While Republicans fought for deeper cuts, the final legislation received bipartisan support in both the House of Representatives and Senate, and Gov. Ned Lamont has said he plans to sign the bill.

Gillett said PURA has worked to increase education and transparency regarding the different components of customer bills, which have brought additional public scrutiny and criticism for regulators.

"PUCs are increasingly faced with a public that's looking at the total bill, including transmission costs that have really grown precipitously for this region over the past decade," Gillett said. "There's always going to be a group of customers that don't want to know more — they just want their bills to be lower — and we have to understand that and meet them where they are."

Regulators throughout the region have faced similar pressure from consumers and legislators. In Rhode Island, when the Public Utilities Commission held a public hearing in March, "people came in, and for about four hours were just screaming at us, after the winter had passed and the rates were about to go down," Chair Ron Gerwatowski said.

Electricity rates typically increase in the winter in Rhode Island because of elevated supply costs. While average rates during the past winter were *slightly lower* than the previous two winters, cold weather increased usage and total bill costs for many consumers.

"Our role as a commission is to kind of take the heat and then work with the legislators in ways that are kind of difficult, but you can make progress," Gerwatowski said. He added that it is important to actively communicate with legislators during price-spike periods to prevent them from doing "stupid things" with "knock-on effects."

In Massachusetts, high supply costs over the past winter coincided with an increased distribution rate, causing bills to increase by about 18% on average relative to the previous winter, according to data from the state Department of Public Utilities.

DPU Chair Jamie Van Nostrand said cost increases in the state's Mass Save program, an energy-efficiency initiative that has been used to promote heat pump installations in recent years, were the biggest driver of high distribution rates, followed by costs associated with the state's Gas System Enhancement Plan

From left: Rhode Island PUC Chair Ron Gerwatowski; Massachusetts DPU Chair Jamie Van Nostrand; and Josh Ryor, Massachusetts EEA | © *RTO Insider*

(GSEP) program, which enables expedited recovery for utility investments to replace leaky gas pipes.

The DPU has taken steps to rein in spending from both programs in recent months, directing a $500 million cut in the three-year Mass Save budget and ordering the utilities to put a greater focus on pipe repair and non-pipeline alternatives in the GSEP. (See *Mass. DPU Aims to Align Gas Leak Program with Climate Strategy*.)

Van Nostrand echoed the need to carefully balance short-term costs and long-term benefits, highlighting the state's push to deploy AMI, which utilities expect to complete by the end of the decade. Despite the high upfront costs, AMI will enable time-varying rates, which should reduce the need for transmission and distribution infrastructure in the coming decades, Van Nostrand said.

Maine Public Utilities Commission Chair Philip Bartlett also expressed optimism about retail demand response and said time-varying rates should lower bills for most customers — even if the customers do not change their usage patterns — and reduce systemwide infrastructure costs.

Bartlett also emphasized the importance of continuing to prepare the grid for new offshore and onshore wind resources, despite the current federal administration's antagonism toward clean energy.

"We need to continue to get ourselves ready so we can bring those resources online as soon as we get the support from the federal government," Bartlett said. ■

Why This Matters

High energy costs have pushed lawmakers to look for both short- and long-term affordability solutions, creating added scrutiny for clean energy and energy efficiency programs.

Consumer Liaison Group Discusses ISO-NE's Failing Accessibility Grade

By Jon Lamson

Why This Matters

Climate and consumer advocates continued to push ISO-NE for a larger role in decision-making processes, while the RTO defended its efforts to reach a wider audience.

Speakers and attendees of the ISO-NE Consumer Liaison Group's quarterly meeting June 4 advocated for governance changes at the RTO after the grid operator received a failing grade on a recent report card on RTO transparency.

The *report*, commissioned by New England-based environmental justice nonprofit Slingshot, graded each RTO and ISO on public accountability, transparency and accessibility. ISO-NE was the only grid operator to receive a failing grade, which the report attributed to the RTO's "exclusive stakeholder process and inaccessible, opaque board proceedings."

The report also detailed concerns about the limited voting power of end-user organizations in the NEPOOL voting process, language barriers, the lack of a "streamlined public comment process" and the entrenchment of existing leadership.

None of the grid operators, however, received higher than a "C+."

Governance issues have been a major topic at the CLG since a coalition of environmental and consumer advocates took control of the CLG Coordinating Committee in late 2022. (See *Climate Activists Take Over Small Piece of ISO-NE*.)

Activists have frequently argued that the nonpublic nature of NEPOOL proceedings and meetings of the ISO-NE Board of Directors prevents meaningful public engagement, while the RTO has pointed to recent steps taken to increase engagement, including annual public board meetings and the addition of an environmental and community affairs policy adviser. (See *In Conversation with ISO-NE's First Community Affairs Policy Adviser*.)

Anne George of ISO-NE addresses the CLG. | *ISO-NE*

Anne George, chief external affairs officer at ISO-NE, called the Slingshot report inaccurate and said it overlooked data and information that the RTO has made available to the public.

"Obviously we're not happy receiving an 'F'; we disagree with a lot of what's in that report, and we think it would have been helpful to talk with the researchers," George said. "I don't think we're planning any major changes in what we're doing based on that report."

Bryndís Woods, principal analyst at the Applied Economics Clinic and one of the report's authors, defended its methodology, stressing that the researchers were only able to consider publicly available inputs. Woods noted that ISO-NE has made recent steps toward translating some materials into Spanish that were not captured in the report.

Charles Hua, executive director of PowerLines, an affordability-focused nonprofit, said cost pressures have caused increased consumer interest in engaging with energy policy issues.

"The vast majority of Americans feel powerless to do anything about their utility bills," Hua said, adding that limited public education and opportunities to engage with public utility commissions and RTOs create "significant risk for all stakeholders in the system."

"It's critical we create opportunities and processes for consumers to participate," he said.

Joshua Macey, associate professor of law at Yale Law School, made the case that RTOs and ISOs across the country, including ISO-NE, structurally favor the interests of incumbent transmission and generation owners.

"What you see across all [RTOs and ISOs] is that the voting empowers entities that owned facilities in the 1990s," Macey said, adding that utilities — and transmission owners in particular — played a major role in establishing the existing governance structures.

NEPOOL voting rules give each of the six sectors an equal share of the voting power and require an approval threshold of 60% for market tariff changes, 66% for non-market changes and 70% for endorsing candidate slates for the ISO-NE board. The high thresholds create a requirement for broad support for rule changes and board endorsements.

While ISO-NE is an independent organization, the transmission and generation sectors, which have a "a significant financial interest in the assets that are already on the system," would have the power to block any slate of candidates for the board, Macey said.

So far, no slate of candidates for the board has ever been rejected. Slates are chosen by the Joint Nominating Committee, which typically consists of members of the ISO-NE board, representatives from each sector and a state representative.

Macey said the power of incumbent interests has contributed to resource adequacy rules that typically "favor incumbent resources" and provide inadequate incentives for resource entry. He also added that the TOs' retention of filing rights over local projects has likely contributed to the high costs of asset-condition projects. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Macey said the RTO has made progress in recent years in changing its rules to enable the addition of new renewables and said electricity restructuring has driven "meaningful cost reductions" and lowered barriers to decarbonization.

"As many challenges as we have here in New England … we should thank our lucky stars that we are not in a vertically integrated market," Macey said. ■

Limited Demand for Large-scale Data Centers in New England

High Electricity Costs Likely to Keep Hyperscale Facilities out of Region

By Jon Lamson

New England is unlikely to see the development of large-scale data centers in the next 10 years but will likely see smaller-scale developments, industry experts said at the New England Energy Conference and Exposition on June 5.

The region has yet to see major data center developments, largely due to high power prices. However, rising demand and capacity costs in PJM and MISO have caused some worries in New England about looming data center-driven load growth.

Even without a significant amount of increased demand from data centers, ISO-NE forecasts the region's peak load to roughly double by 2050 due to heating and transportation electrification, which would require the region to add a massive amount of new generation and transmission capacity.

The RTO estimates the region will need to add about 97 GW of clean energy capacity to meet state decarbonization goals. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B* and *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.)

Representatives of companies developing large-scale data centers said they are not currently developing projects in the region, citing the high cost of power.

What drives interest in data centers is "where is there existing power and where are there existing customers," said Judith

From left: Tanya Bodell, StoneTurn; Judith Judson, Vantage Data Centers; Morgan Steacy, National Grid; Sharon Midgley, Constellation | © *RTO Insider*

Judson, senior vice president at Vantage Data Centers.

"In terms of operating costs, power really matters, and the price of power comes in substantially," Judson said. "Power prices in the Northeast happen to be higher than in other parts of the country. But that doesn't mean that this isn't an area for growth."

While load growth from data centers has yet to show up in New England, both Massachusetts and Connecticut have passed tax incentives in recent years to boost development. Massachusetts lawmakers in 2024 passed a bill exempting data centers from the state's sales tax, while Connecticut *allows* data center developers to apply for an up-to-30-year sales and property tax exemption.

These incentives appear to have spurred some increased interest in data center development. In Western Massachusetts, the Westmass Area Development Corporation *aims to build* a $3 billion data center complex, though the not-for-profit development group has yet to announce anchor tenants for the project. In Connecticut, Dominion Energy has received requests from developers to co-locate data center facilities at the site of the Millstone nuclear plant.

"The amount of service requests we have in our service territory exceeds the peak load of Maine and New Hampshire combined, [though] we don't know if these are real or speculative," said Vandan Divatia, vice president at Eversource Energy. "We can enable some of these resources in a very strategic and measured way in various locations throughout our system."

Morgan Steacy, vice president of connections and strategic accounts at National Grid, said the company has seen "some incremental growth" in data center connection requests after Massachusetts passed its incentives in 2024.

"Will we ever house hyperscalers? If I had to bet, no," Steacy said, adding that the state could see continued interest in smaller data center applications. She encouraged companies to reach out if they are interested in developing in the state, and said National Grid can help companies navigate the permitting and siting process.

Potential for Demand Flexibility

"The data center industry is not monolithic," said Lucas Fykes, director of energy policy at the Data Center Coalition, noting that the potential for demand response will vary significantly between different facilities.

He said demand response capabilities often depend on whether a data center is a single- or multi-tenant facility and said it can be easier to reduce the load of a single-tenant facility, when the tenant can shift demand to a different facility.

Brendon Baatz, who works in energy market development at Google, said some of the company's data centers have demand response capabilities and that it is working to shift loads between facilities to minimize its overall emissions impact. He said this strategy is a key aspect of meeting the company's goal of matching all its power demand with carbon-free energy on an hourly basis by 2030.

Judson said peak shifting "isn't so much available" for the company's facilities but added that "on very hot peak days, we can shift some to backup generation to take some of the load off the grid."

Ultimately, as data centers come online, the facilities should not be treated any differently than other large sources of load, several speakers urged.

"It should be a very large customer tariff," said Judson, who warned against overbearing interconnection requirements and called for collaboration among a wide range of stakeholders to establish rules for interconnecting data centers in a way that will both "serve our needs and protect ratepayers."

"The answer to the question of whether we need a data center tariff is absolutely not," Baatz said. "I do not think it needs to be specific to data centers, because there are other large loads coming onto the grid, and those should not be treated any differently than data centers."

(For more coverage from the New England Energy Conference and Exposition, see *New England Regulators Weigh Short-term Costs and Long-term Savings*.) ■

Why This Matters

With ISO-NE already projecting the region's peak load to roughly double by 2050 due to electrification, significant data center growth could pose a major challenge for the New England power system.

NOLA City Council Puts Entergy, MISO in Hot Seat over Outages

Officials Summoned to Explain Risk Preparedness, Notifications, Tx Planning

By Amanda Durish Cook

Called to the podium by the New Orleans City Council, MISO and Entergy leadership agreed that a perfect storm of factors merged to cause the Memorial Day weekend power outages in the metro area.

The council convened a special Utility Committee on June 3 to grill MISO and Entergy leadership. MISO delivered 600 MW in load-shed orders May 25 in a last-ditch effort to maintain the system before something more catastrophic could befall the grid. The RTO ordered 500 MW offline in the Entergy territory and 100 MW offline in the Cleco territory. (See *MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat*.)

Senior Vice President and Chief Customer Officer Todd Hillman said with a "short amount of customer impact," MISO was able to avert a "larger, more far-reaching" outage event.

Hillman said it's "frustrating" that MISO cannot single out a source of the outages. Rather, he said it was a "culmination of factors."

"It wasn't one thing that happened. It wasn't one thing you can point to and say, 'oh OK, it was that transmission line' or 'oh OK, it was that unit,'" Hillman said. He said while MISO's earlier modeling showed Louisiana would come through May 25 without issue, in the literal heat of the day, conditions changed.

In all, about 4.5 GW of generation was out in the area at the time, including Entergy's Waterford and River Bend nuclear stations, the latter of which unexpectedly flickered off days before due to a cooling leak. The limited generation availability coincided with offline and overloaded transmission facilities. At the time, Entergy's 500-kV transmission path near Jennings, La., remained out of service from a March tornado.

"We had a number of units that were [on] unplanned outages during that week. The good news is most of those are back on. So, they were working through that to get back on. In fact, that major transmission line to the west was back on two days after the event. So, they're working feverishly to get ready for the peak season; it was just that all of these things sort of came together for that one, single moment," Hillman said of MISO South utilities following the event.

The June 3 special Utility Committee meeting of the New Orleans City Council | *New Orleans City Council*

The Bottom Line

Following the late May blackout, the New Orleans City Council convened a special meeting to question MISO and Entergy over their moments leading up to load shedding, communications to the public and transmission planning.

Hillman assured the council that MISO works with its members to expand transmission and generation plans to make sure MISO South is reliable. He said MISO studied and approved the planned generation outages months before the event.

But he also said south Louisiana lacks import ability and can be affected when local generation is sparse.

Executive Director of Market Operations JT Smith said MISO is delving into why it experienced so many outages that week. He said the biggest change from days leading up to the outage to May 25 was an uptick in load due to hotter temperatures.

'Plane Crash'

Council member Oliver Thomas questioned MISO's deftness that day as the "air traffic controller" of the power grid. MISO leadership often makes the analogy.

"The plane didn't land. It crashed," Thomas said.

"We prevented a crash by making sure that plane never took off," Hillman responded.

Thomas asked how many customers lost power that day. Hillman and Smith confirmed it was about 100,000.

"Tell them it was a landing," Thomas retorted.

Hillman said he wasn't trying to suggest there wasn't a problem but stressed that MISO managed to avoid rampant, unchecked blackouts.

Council member Jean-Paul "JP" Morrell said a more suitable analogy might be likening the blackouts to the city's periodic flooding when its pumping system is overwhelmed and decisions are made to release water in one neighborhood to save the larger city.

"Though the rest of the city celebrates not being flooded, the one neighborhood that is flooded is rightfully pretty upset about it and pretty pissed," Morrell said.

MISO identified the risk of an interconnection reliability operating limit (IROL) violation at 4 p.m. CT on a transmission constraint on the north shore of Lake Pontchartrain. After 20 minutes where it conducted an analysis of available options, MISO called upon Entergy to commence load shed in the New Orleans and Slidell areas. MISO directed Cleco to shed load about 10 minutes after it delivered instructions to Entergy.

Entergy New Orleans CEO Deanna Rodriguez | *New Orleans City Council*

JT Smith (left) and Todd Hillman of MISO attend the special June 3 New Orleans City Council Utility Committee meeting. | *New Orleans City Council*

"We want to make sure double, triply, quadruply sure that's the only course of action that we have at that point," Hillman said of the 20 minutes of review time.

MISO, Entergy Vow to Improve Notification Time

Council member Eugene Green said residents needed more time to prepare and questioned why an alert was not sent out through NOLA Ready, the city's emergency preparedness texting *system*.

Hillman said MISO is considering introducing more notifications to give the public "fair warning" about its risk posture.

Hillman and Smith emphasized throughout the hearing that NERC allots grid operators 30 minutes to get load off the system to prevent larger blackouts once it's clear that an IROL issue is a possibility.

"We should have been communicating much greater externally that we were on that precipice," Smith said. He added that even though MISO was "on the cutting edge" from May 22 onward managing congestion, MISO believed it would navigate the event without resorting to drastic measures.

Smith said prior to the event, MISO and Entergy had compared notes and had a mitigation plan at the ready. However, he said in the moment, for reasons that MISO has yet to understand, the agreed-upon transmission reconfiguration solution wasn't viable.

"So yes, it would have surprised everyone participating in it," Smith said.

Hillman said MISO hoped to avoid an IROL situation by talking through mitigation plans ahead of time.

"Those solved until they didn't solve when we got to the real-time conditions," Hillman said. Hillman said MISO conducted a "tremendous" amount of analysis on system conditions leading into May 25.

MISO ultimately was able to use the reconfiguration plan a few hours after it instructed the utilities to shed load as it restored power.

Though Entergy maintained a day after the outages that it had not seen a reason to shed load, company officials who appeared at the meeting said it was necessary.

Entergy New Orleans CEO Deanna Rodriguez said MISO's load-shed orders served to avoid a "potentially catastrophic outage such as occurred recently in Portugal and Spain." She said the circumstances were beyond Entergy's "immediate control" and apologized to council members.

"We are working closely with MISO to

better understand this highly unusual event and what can be done to prevent this from ever happening again," she told council members. She said Entergy New Orleans would take pains to be "more aligned with MISO" in order to give ratepayers more notice.

Fielding questioning over the comprehensiveness of Entergy's risk modeling, Rodriguez said while Entergy and MISO plan workarounds for maintenance outages, unplanned outages, hot weather and transmission outages, those variables never have all lined up at the same time. She also said Entergy didn't know its reconfiguration plan would not have worked until MISO informed the utility in real time. Rodriguez said that failure will inform Entergy's training and planning going forward.

Hillman said it's not surprising MISO's wider view of system vulnerabilities contradicted Entergy's risk estimations up to the load shed.

Smith said load shedding to avoid potential collapse from IROL violations is an extremely rare event in MISO. He said a load-shed event during Winter Storm Uri in 2021 and an incident around 2014 in Baton Rouge when generation and transmission went down suddenly were the only other instances he could think of in his 20 years at MISO.

Entergy Senior Vice President Power Delivery Charles Long said Entergy, like MISO, believed it wouldn't find itself in a load-shed situation over the holiday weekend.

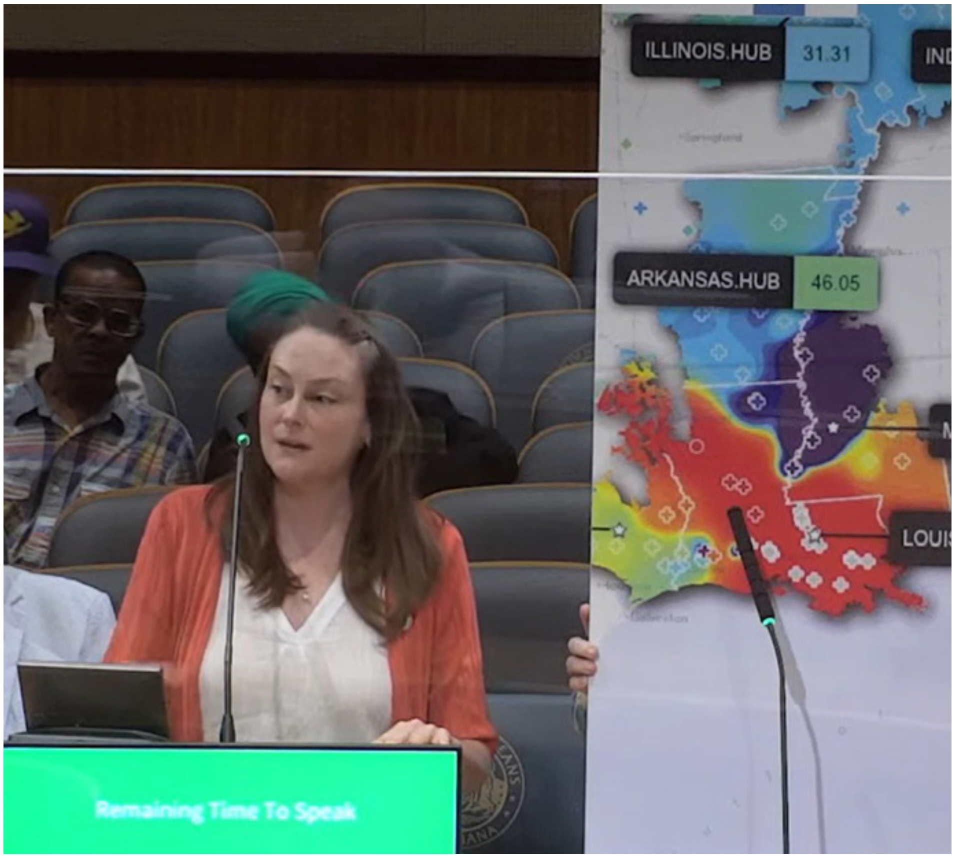
Long said no significant transmission or generation outages occurred on May 25, with the unplanned generation outages all starting before the weekend.

"We knew that Memorial Day weekend was going to be a challenge. We knew that it was tight," Long said.

Long said Entergy now understands the reconfiguration plan MISO and Entergy worked out would have failed, per MISO's broader modeling. He said while catastrophic outages tend to develop slowly, "this one was rare and evolved very quickly."

Council members repeatedly asked who decided which neighborhoods should go without electricity.

Long said Entergy operators choose to



Alliance for Affordable Energy's Logan Burke displays MISO's May 25 pricing at the special Utility Committee meeting June 3. | *New Orleans City Council*

interrupt substations based on maximum relief on constrained transmission, without worsening system conditions, with fewest customers impacted. He said there was no time to be "surgical" and shed load according to its usual prioritization of critical loads. Long said Entergy didn't have time to single out its interruptible industrial customers and instead cast off load closest to the problem area.

Morrell said he learned of the load shedding only when the power was cut. He said he didn't know "what the hell was going on," undermining his ability to regulate Entergy. He said from his perspective, Entergy could have notified regulators sooner of the grid stress and could have made public appeals ahead of the weekend for customers to lower usage.

"There's always going to be that jerk that keeps his AC on 60," Morrell added.

Entergy officials confirmed the New Orleans Power Station, a controversial, 128-MW gas generator built in 2020 and touted for its black start capability, was running at the time and helped to avoid further outages of about 25,000 customers. (See *Entergy Touts Restoration; NOLA Leaders Question Lack of Blackstart Service*.)

Council member Helena Moreno said it might be time for Entergy to weigh adding a battery storage facility to the New Orleans Power Station.

Attention Turns to MISO South Tx Planning

"Let's talk about the bigger issue. The bigger issue here is we have not had the level of transmission development in our area that we should have," Moreno said, adding that she remembered writing a letter urging MISO South transmission planning in the aftermath of Hurricane Ida in 2021.

Louisiana Public Service Commissioner Davante Lewis, who was a guest at the invitation of the city, said southeastern Louisiana not being able to access otherwise plentiful electricity to the north is evidence the region needs transmission planning.

Moreno asked MISO when it would focus its long-range transmission planning on MISO South. MISO long-term planning so far has focused solely on MISO Midwest;

the RTO has planned to draft a third portfolio for the Midwest region before it focuses on the South.

Hillman said between 2017 and 2023, MISO South utilities independently planned about $13 billion in local transmission projects that MISO has approved.

"While they may not be doing it in that same, grandiose way as the North and Central [regions], there's actually a lot of transmission planning happening in this region along with generation planning," he said.

But Hillman acknowledged MISO South was "owed" a long-range transmission plan. He said MISO could begin a MISO South long-range transmission portfolio as soon as sometime in 2026.

In response to council members' questions over Entergy's receptiveness to transmission planning, Long said Entergy has transmission planned that might have helped the May 25 situation: a 230-kV Adams Creek-to-Robert *line* and 230-kV and 500-kV reliability *projects* around the Amite South load pocket.

However, Lewis said those planned projects appear tailored to serve growing industrial load and aren't "necessarily combatting the transmission lock hold" that exists in the South.

Long likened the upgrades to a "tide that raises all ships," meaning they will serve new load while strengthening MISO South's system.

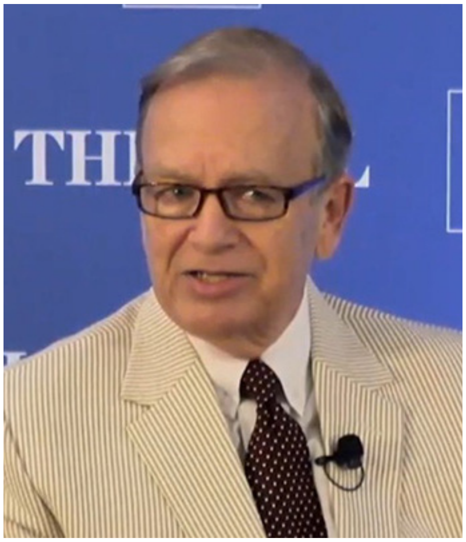
Lewis asked if Entergy believes FERC's Order 1920 is a positive development. Long said he would have to read Order 1920 first to answer the question.

Long added that Entergy got to work as quickly as it could to rebuild the 19 damaged structures of the Jennings 500-kV line before summer. However, he said the company encountered some supply chain issues getting steel to finish repairs.

Consumer Advocate Faults Regulator Inaction

Consumer and environmental advocate Alliance for Affordable Energy held a June 2 virtual town hall meeting where they asked the public to pressure regulators to demand meaningful planning from Entergy.

Yvonne Cappel-Vickery, an organizer with the alliance, said this "won't be the last load-shed event unless we deploy solutions." She said Louisianans need demand response programs and renewables paired with battery storage in the short term and more transmission capacity in the long term.


Louisiana Public Service Commissioner Eric Skrmetta | *The Hill*

"We need more lanes, and we need more highways to move power," Cappel-Vickery said. She said despite "finger-pointing" over blackouts, elected officials in the New Orleans City Council and the Louisiana Public Service Commission deserve much of the blame.

Cappel-Vickery said it's the elected officials' responsibility to push utilities to incorporate assets like battery storage and plan long-term transmission. She said they've been derelict in their duties to guide utilities and need to be "held accountable for the situation they have created."

The Alliance for Affordable Energy denounced Entergy for suggesting MISO alone was the originator of the curtailments.

"While MISO ordered the load shed to limit larger outages, inaction by Entergy, Cleco and their elected regulators created the conditions requiring those blackouts," the Alliance wrote in a June 2 letter to the New Orleans City Council. "This blackout could have potentially been avoided if regulators had been consistently pushing our regulated utilities to begin regional transmission planning and investment years ago. Instead of encouraging utilities to begin transmission planning, Louisiana regulators have allowed costly consultants to quibble over cost allocation methodologies without finding a solution."

"It was a perfect storm with this one. It was a lot of unplanned outages," Southern Renewable Energy Association Transmission Director Andy Kowalczyk summed up during the webinar. He said MISO acted swiftly to dodge a more serious outage that could have taken several days to resolve.

Kowalczyk appeared at the council meeting to request MISO South get similar planning treatment as MISO Midwest. He also said grid operators are time and again "caught off guard" with unplanned outages of thermal generation and said utility-scale renewable energy and storage could assist the region.

Meanwhile, Louisiana Public Service Commissioner Eric Skrmetta did not address the southeastern Louisiana blackouts when he appeared during *The Hill*'s "Securing the Grid: Powering the Gulf South Region" June 2 conference and webinar sponsored by Entergy.

Skrmetta focused instead on outages in the aftermath of hurricanes. He said while post-storm outages years ago lasted "18-20 days," outages now last one to two days. He said outages in the Gulf South are inevitable while the Louisiana PSC works with utilities and urged public patience.

Skrmetta also touted Louisiana's low electricity rates and said they're the product of the commission being tough on utilities.

"We put strong demands on our utilities to achieve these goals. … We don't actually knuckle under to our utilities. We work this out," Skrmetta said. "We've trimmed off things that we don't think the ratepayers should be paying for."

Skrmetta said he wanted more industrial load and power plants to come to Louisiana and said he's "agnostic" about the types of industry attracted to the region or the types of electricity that ultimately serve them.

"Whatever the cocktail of megawatts that they're searching for, Louisiana is going to provide that," he said.

The Louisiana PSC will hold its own hearing over the blackout on June 18. ■

MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey

By Amanda Durish Cook

The Organization of MISO States and MISO are confident the footprint will be resource-sufficient in the 2026/27 planning year but said anything from an 11.4-GW surplus to a 14.1-GW deficit could be in store by the 2030/31 planning year depending on how swiftly capacity can be added.

The two drew on more generous capacity construction assumptions than in years past to come up with the 2025 OMS-MISO Resource Adequacy Survey *results*. MISO said it likely would have a surplus anywhere from 1.4 GW to 6.1 GW for summer 2026 based on survey totals.

For summer 2027, the five-year resource adequacy projection showed the potential for a 5-GW deficit or a 6.4-GW surplus. From there, the possibilities for excesses or shortfalls widen further.

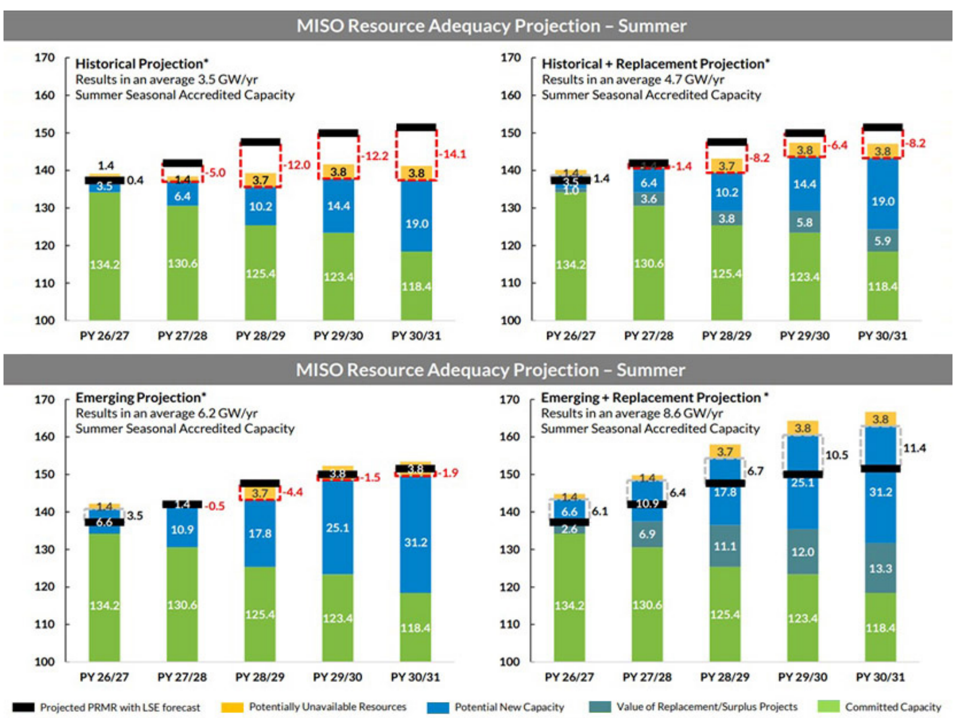
MISO Senior Resource Adequacy Engineer David Kapostasy said OMS and MISO used a range of build rates for this year's survey, including a more promising replacement trend for retiring generation.

The two used a 3.5-GW/year assumption for capacity builds, based on a three-year historical average of new capacity constructed 2022 through 2024. Factoring in MISO's historical, 1.2-GW rate of generation replacement projects brought the baseline average to 4.7 GW/year. MISO and OMS also used a more optimistic, 6.2-GW/year alternative projection based on MISO members' responses to the survey regarding generation plans. Furthermore, MISO said high-end value could grow to 8.6 GW/year using a more generous, 2.4-GW/year replacement rate that reflects an emerging trend of utilities more reliably choosing to build replacement capacity or, better, using surplus interconnection service at existing sites.

Using the 3.5-GW/year build rate alone, MISO could experience a 12-GW shortage by summer 2028. At the 8.6-GW/year rate, however, the deficit dissolves into a 6.7-GW overage. While the 3.5-GW rate returns 12.2- and 14.1-GW shortages in planning years 2029/30 and 2030/31, respectively, the 8.6-GW/year rate could deliver 10.5 and 11.4 GW in extra capacity over summertime needs.

Why This Matters

The 2025 OMS-MISO RA Survey doesn't paint as bleak a picture than it has in years past of the footprint's resource sufficiency. More optimistic about new capacity turnaround times, MISO allowed for the possibility of an 11-GW surplus in 2030. However, it served that prospect alongside the familiar, more glum chance of a 14-GW shortage.



MISO's low-end (top) and high-end resource adequacy projections under the 2025 OMS-MISO Resource Adequacy Survey | *MISO*

It's not until MISO applies the 8.6-GW/year average that the possibility of any capacity shortfall is eradicated from the 2027/28 planning year onward.

MISO compared capacity estimates against 2.2% compound annual load growth, instead of last year's 1.6%.

Last year's OMS-MISO survey drew on a 2.3-GW/year build rate for accredited capacity based on new capacity built between 2020 and 2022 and a high-end, 6.1-GW/year estimate. (See *OMS-MISO RA Survey: Potential 14-GW Capacity Deficit by Summer 2029*.)

This year's survey results are the first time in a few years that MISO and OMS are entertaining the possibility of double-digit gigawatt reserves in summer. The 2024 survey's best-case scenario showed a 4.6-GW surplus by the 2029/30 planning year. Capacity deficits, according to the 2024 survey, also could top out around 14 GW.

At a June 6 teleconference to review survey results, Kapostasy said MISO reflected an acceleration in construction turnaround times among its membership when preparing survey totals.

"There's a question of: Is this the queue

Continued on page 39

MISO Drafts Joint Planning Agreement with AECI

MISO has drafted a joint transmission planning agreement with neighbor Associated Electric Cooperative Inc. (AECI) that is premised on how the two coordinate today.

MISO and Springfield, Mo.-based AECI work together when they have generator interconnection requests at their seams. The two use an affected system study process to coordinate on system upgrades necessary for interconnecting generation.

At a June 3 Interconnection Process Working Group meeting, MISO's Liang Qi said the agreement largely memorializes what the RTO and AECI already have been doing.

The agreement details MISO's and AECI's data exchange for studies, cost recovery for studies, requirements for facility construction agreements and how the two will honor relative queue positions in studies. It will provide for the analysis of generation interconnection as well as merchant HVDC transmission connection requests.

AECI's coal-fired New Madrid Power Plant in Missouri | *AECI*

When one of the two encounters a generation project that strains the system, AECI or MISO would draft a description of the required network upgrade and provide planning-level cost estimates and an estimated construction timeline. The two decided that interconnection requests assigned an affected system upgrade would have only "limited operation" until the upgrades are in service.

Under the agreement, MISO would get 120 calendar days for its initial affected study and an additional 60 days to complete a restudy, if necessary. AECI, on the other hand, would work on 90-day limits for its two study phases with a 60-day restudy provision for late-stage withdrawals.

Qi said MISO will present the agreement for review in July to the Planning Advisory Committee. He said the RTO is targeting a September filing for FERC approval.

AECI, a member-owned nonprofit cooperative, is not FERC-jurisdictional. Its territory includes rural Missouri, northeast Oklahoma and southeast Iowa. ■

— Amanda Durish Cook

MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey

Continued from page 38

starting to unclog itself, or is this a return to normal," pre-COVID construction tempos, Kapostasy said.

Kapostasy said this is the first year MISO projected replacement capacity and new capacity that may result from surplus interconnection service, recognizing that many existing interconnection customers already replace generation or explore using their existing interconnection service to the fullest.

Replacement and surplus interconnection projects should account for 25% of new capacity additions over the next five years and blunt the impact of retirements, Kapostasy said. He also said retirement deferrals in MISO are providing a "short-term buffer" against seasonal capacity deficits.

MISO this year attempted to quantify in survey totals what it calls "stranded GIAs," or projects with signed generation interconnection agreements that nevertheless won't become part of MISO's capacity expansion due to difficulties getting them built.

Kapostasy reminded stakeholders that MISO has about 54 GW worth of planned generation that has signed interconnection agreements but are not yet online. He added that MISO's recent queue process alterations (read: an annual megawatt cap on project entrants, higher dropout fees and an automated study process) should attract generation projects that are more of a sure thing in the future, minimizing dropouts.

MISO said 91% of existing generation participated in the 2025 OMS-MISO Survey, representing 97.4% of MISO load.

Vice President of System Planning Aubrey Johnson said the bottom line is MISO appears to have sufficient resources for the next planning year.

"Beyond that, we have challenges that need to be met," he said.

Joe Sullivan, president of the Organization of MISO States and vice chair of the Minnesota Public Utilities Commission, said past surveys seemed to help move the needle on improving MISO's resource adequacy picture.

"Capacity margins have improved since last year," he said.

Sullivan said the goal of the survey is to guide planning decisions, "not deliver definitive" projections. He said many variables, including load growth, electrification and fleet turnover, remain in flux.

"As the survey shows, we are continuing to meet the moment," Sullivan said. ■

MISO's 2022 and 2023 Queue Study Cycles Delayed Again

By Amanda Durish Cook

MISO's 2022 and 2023 generator interconnection queue cycles are lagging behind their stated timelines once again as the RTO continues working to produce study results in a new, automated process.

The grid operator said it now will post a final system impact study for the 2022 cycle July 8 and move those generation proposals to the second phase of the three-part queue by Aug. 6. It will move on to studying project applications submitted in 2023 on Aug. 20.

This is MISO's second postponement for the 2022, 2023 and 2025 queue cycles. The grid operator skipped acceptance of a 2024 cycle while it tried to get a handle on study delays and design a megawatt-capped queue that could sort out projects over a one-year span instead of three to four years.

In January, MISO planned to begin studying the 2023 cycle in May and the 2025 cycle by the end of the year, a few months behind the schedule it announced in 2024. At the time, the grid operator envisioned all generation projects from the three cycles striking interconnection agreements over 2026, with the 2022 cycle proceeding in the second quarter, 2023 in the third quarter and 2025 by the end of 2026. (See *MISO Unveils Later Timeline for Queue Processing Restart*.)

MISO's Kyle Trotter said MISO would post a new schedule soon detailing when it will proceed with the 2025 cycle of projects.

Senior Manager of Resource Utilization Ryan Westphal said MISO wants to finalize the 2022 cycle's system impact study after multiple rounds of adjusting modeling assumptions at stakeholders' suggestions and presenting different drafts of the study for review.

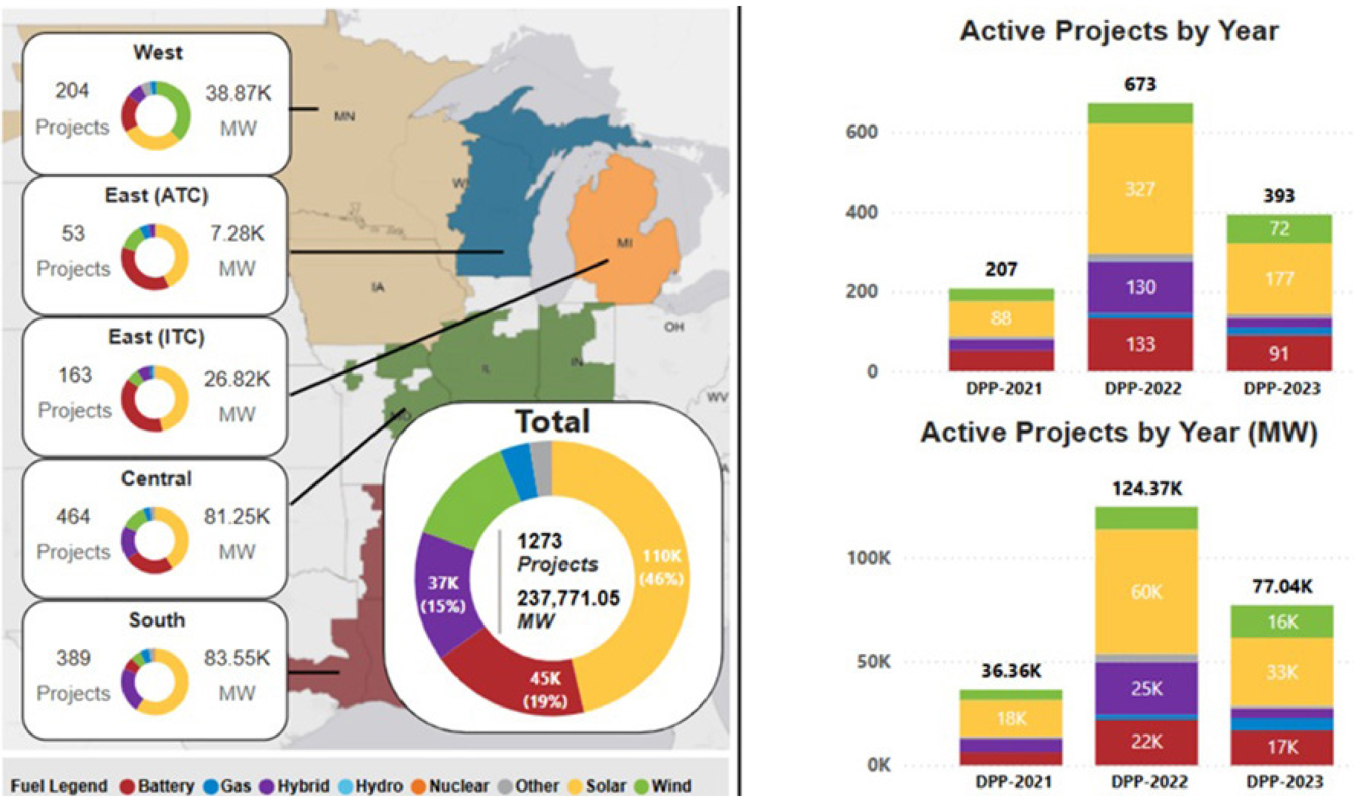
"We're ready to move forward at this point," Westphal said during a June 3 teleconference focused on MISO's interconnection process. He added that MISO will account for project withdrawals from the 2022 cycle in the screening process for the 2023 batch of projects.

MISO is using Pearl Street's automated *SUGAR* (Suite of Unified Grid Analyses with Renewables) study software to screen generation projects and perform the first phase of studies in the queue. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

Westphal said MISO's later, Aug. 20 study kickoff also would give the RTO time to seek FERC approval to include MISO and SPP's $1.65 billion Joint Targeted Interconnection Queue (JTIQ) portfolio in its modeling for the 2023 cycle of generation projects. The move is unpopular among MISO's generation developers, who are set to shoulder all JTIQ costs; they've said the cost allocation could attach high, unpredictable expenses to their projects. (See *MISO Gen Developers Sour on RTO's JTIQ Cost Allocation*.)

"We want to make sure we have enough time to hear back from FERC," Westphal said.

MISO has 1,273 projects totaling 237.8 GW in its interconnection queue. ■



A breakdown of MISO's generator interconnection queue as of May. Projects don't include the 2025 queue cycle. | *MISO*

Constellation, Meta Sign 20-year Nuclear PPA

Deal Will Keep Clinton Reactor in Service After Illinois ZECs End

By John Cropley

Meta has signed a 20-year power purchase agreement for the output of Constellation Energy's 1,121-MW *Clinton nuclear plant* in Central Illinois, the companies announced June 3.

The deal will begin in June 2027, upon expiration of the state's zero-emission credit program that has been subsidizing operation of the plant. The PPA in effect will replace the ratepayer-funded ZECs.

In their announcements, Constellation and Meta hailed the deal as a landmark market-based solution to keep older nuclear facilities online, producing high-capacity-factor baseload power without carbon emissions.

With 38 years in service, Clinton is among the youngest U.S. commercial reactors. It was operating at a continuing loss in the mid-2010s and was slated for early retirement, but Illinois created the ZEC subsidy in 2017, returning it to profitability.

The facility's license extends through April 2027. Constellation in 2024 *filed an application* with the Nuclear Regulatory Commission for a 20-year renewal, with the caveat that how long it actually operated the reactor would depend on the economics and on policy support.

As part of the agreement with Meta, Constellation will perform uprates that will add 30 MW to the existing 1,092-MW nameplate capacity of the facility.

Constellation is now considering seeking an extension of Clinton's existing early site permit or seeking a construction permit for an advanced reactor or small modular reactor to be co-located with the existing facility, located in Zone 4 of MISO's capacity market.

Why This Matters

Big Tech's latest foray into nuclear power relieves ratepayers from having to subsidize expensive nuclear facilities.

The Clinton Clean Energy Center in Central Illinois | *Constellation Energy*

In September 2024, the company *announced a PPA* with Microsoft for output from the Crane Clean Energy Center — the former Three Mile Island Unit 1, which it retired in 2019 for economic reasons. The company had begun the decommissioning process but is currently working to restart the reactor.

In *Constellation's news release*, CEO Joe Dominguez asked rhetorically why Three Mile Island had shut down in the first place, and said Meta had asked a similar question about the future of Clinton.

"They figured out that supporting the relicensing and expansion of existing plants is just as impactful as finding new sources of energy," Dominguez said. "Sometimes the most important part of our journey forward is to stop taking steps backwards."

"Securing clean, reliable energy is necessary to continue advancing our AI ambitions," said Urvi Parekh, Meta's head of global energy.

Meta also provided an *update* June 3 on its advanced energy ambitions, as it seeks to match the electricity used in its data centers with 100% clean and renewable energy. It said that as it considers emergent technologies, it recognizes the value of the firm, reliable capacity offered by nuclear fission.

The tech giant said it has received more than 50 qualified submissions in response to its *nuclear request for proposals* and is in final discussions with shortlisted developers for potential projects.

Meta is focusing on sites where nuclear development can be advanced with speed and certainty as it tries to assemble a 1- to 4-GW portfolio of projects. It hopes to finalize the process this year.

All of this, and the Constellation PPA, are intended to send signals of support and demand to the nuclear sector, Meta said: "Our investments in nuclear energy ensure that we will have the robust energy infrastructure needed to power the AI innovations that are set to spark economic growth and prepare our communities for the future." ■

NYISO Makes Case for Repowering in Latest 'Power Trends' Report

By Vincent Gabrielle

Amid increasing demand and dwindling supply, repowering aging fossil plants would help maintain reliability while still lowering emissions in line with New York's climate change policy goals, NYISO argues in its annual "Power Trends" *report*, released June 2.

Repowering, or retrofitting, older units "can offer a bridge between old and new, the past and the future," the ISO says. "Upgrading our existing fleet not only can help with a stepped approach to carbon reductions by replacing older, dirtier turbines with new, cleaner cutting-edge technology, it also holds the potential for helping avoid future generator breakdowns, therefore bolstering grid reliability."

Much of the report repeats the same concerns as the past few years: not enough renewables coming online to replace retiring fossil-fired plants, with new large loads being added to the grid at an accelerating pace.

"The grid is undergoing rapid and instrumental change," NYISO CEO Rich Dewey said in a press release announcing the report. "We continue to observe declining reliability margins while forecasting a dramatic increase in load. It's imperative during this period of transition that we maintain adequate supply to meet growing consumer demand for electricity."

The ISO lists examples of repowering for different fuel types; for example, for wind resources, "replacing turbines with greater capacity or upgrading older blades with more efficient technology can improve energy yield."

But it also notes elsewhere in the report that about 25% of New York's total capacity consists of fossil fuel plants that have been operating for more than 50 years.

"As these fossil fuel generators age, they are experiencing more frequent and longer outages," NYISO says. "Greater difficulties in maintaining older equipment, combined with the impact of policies to restrict or eliminate emissions, may drive aging generators to deactivate, which would exacerbate declining reliability margins."

It goes on to say that "only New York's existing fossil resources and certain hydro generators deliver the full array of services needed to balance a dynamic grid. Despite the need to reduce fossil fuel use to meet the state's emissions-reduction targets, some level of fossil-fired generation will be needed for reliable power system operations until the capabilities they offer can be provided by other resources."

Gowanus barge-mounted natural gas generating station in Brooklyn, N.Y. | *Astoria Generating Company*

Why This Matters

NYISO joins the RTOs becoming increasingly vocal about maintaining the existing fleet of fossil fuel plants in the face of rising demand.

But the NYISO Market Monitoring Unit noted in its State of the Market *report* for 2024 last month — and as New York regulators have acknowledged — development of new renewable and storage resources is severely lagging the state's targets. The Climate Leadership and Community Protection Act (CLCPA) required a 70% clean generation mix by 2030, a target officials have admitted is likely already out of reach. (See *N.Y. Moves to Boost Lagging Clean Energy Development*.)

"While over 14 GW of Tier 1 awards have been announced under the [Clean Energy Standard], just 9% have entered service, while 61% have been canceled, and most of the remainder have not yet moved forward with construction," the MMU wrote. Among the reasons listed for the delays and cancellations are weak nonperformance penalties, giving developers increased incentive to submit more aggressive bids. "Consequently, awards are more likely to go to projects that are relatively unlikely to be constructed."

The report "clearly demonstrates that the time for state action is now," Gavin Donohue, president of the Independent Power Producers of New York, said in a *statement*. "Energy consumption will continue to increase as New York strives to achieve its electrification goals, and that will require a diverse energy portfolio, as well as modernized generation units. This report further proves that the aging units and repowering opportunities need to be addressed as they are critical components of New York transitioning to a cleaner energy future in a reliable, affordable and responsible fashion." ■

PJM Board Initiates CIFP Process for Eddystone Compensation

RTO Seeks to Develop Way to Compensate Emergency RA Generation

By Devin Leith-Yessian

PJM's Board of Managers on June 9 *initiated* a Critical Issue Fast Path (CIFP) process to determine how to compensate Constellation Energy for continuing to run two gas-fired units at the utility's Eddystone plant under a Department of Energy emergency order.

While PJM and MISO both have provisions to compensate generation that must remain online to maintain transmission reliability, they lack mechanisms for retaining and paying resources whose deactivation is delayed for resource adequacy purposes.

The announcement initiating the CIFP process said the purpose is to "engage with stakeholders and to receive feedback on the specific issue of the appropriate cost allocation methodology associated with the recovery of the DACC [deactivation avoidable cost credit] payments to Constellation for the Eddystone Units."

The board communication states that Constellation agreed to use the DACC to determine compensation for keeping units 3 and 4 at the 760-MW Eddystone plant online. However, PJM's tariff only contemplates applying the credit for units serving under reliability-must-run agreements for transmission purposes. (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online*.)

"This discussion may also include the potential establishment of a generic cost allocation structure that could be utilized in the event that additional [Federal Power Act Section] 202(c) orders are issued in the future for resource adequacy purposes, and the generator owners subject to those orders elect to utilize the DACC as their form of compensation," the communication says.

Since the emergency order requires the Eddystone units to be operational on June 1, the CIFP process will proceed on a shortened timeline beginning with a problem statement, issue charge and solution proposed on June 10 and stakeholder feedback and alternatives solicited on June 12. A meeting for package development will be held on June 16, and a June 18 meeting will review the final proposed solution and allow "members and invited non-members" to provide feedback to the board.

Consumers Energy has filed a complaint against MISO asking FERC to require the RTO to file tariff revisions detailing how it will compensate generators required to defer their deactivations under Section 202(c) emergency orders. Consumers' 1,560-MW J.H. Campbell generator in Michigan has also been required to remain operational under a separate DOE emergency order (*EL25-90*).

"To be clear, the specific costs, if any, to be recovered by Consumers Energy are not at issue in this complaint. Rather, Consumers Energy plans to make a Section 202(c) filing after the conclusion of the extended service required by the DOE order in which it will present, explain and support what it believes are its just and reasonable costs associated with running the Campbell plant from the date of the DOE order, netting out applicable market revenues," the complaint states.

'False Narrative'

PJM's Mike Bryson | © *RTO Insider*

The Eddystone emergency order was also discussed at the June 3 PJM Operating Committee meeting, at which Senior Vice President of Operations Mike Bryson reiterated the RTO's support for the order.

"PJM did not initiate the request for the emergency order; PJM does support the emergency order," he said.

Bryson said DOE reached out to PJM to inquire about generators that have requested deactivation, with a particular focus on "immediate concern generation" that would go offline by the end of May. The RTO responded by providing a spreadsheet of resources that are set to retire, highlighting those that are set to go offline in the next three years and are seeking to withdraw their deactivation request.

The emergency order was facilitated by an April 8 executive *order* that widens how the Section 202(c) authority may be used, which Bryson said sparked PJM's interest due to the focus on retaining generation found to be critical to maintaining resource adequacy and preventing resources over 50 MW from deactivating or changing their fuel type if the conversion would reduce accredited capacity. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

Bryson said PJM has been vocal in congressional testimony about projected resource adequacy issues, load forecasts and its February 2023 "Energy Transition in PJM: Resource Retirements, Replacements & Risks" position *paper*. (See *PJM Whitepaper to Highlight Future RA Concerns*.)

In a June 2 *statement*, the Delaware Riverkeeper Network disputed that there is any emergency requiring Eddystone to remain online and said its continued operation harms public health and degrades water and air quality. It argued that Eddystone contributes to high ozone concentrations that exceed federal standards.

"Our nation has excess fossil fuel energy, so much so that it is being exported to countries oversees," Maya van Rossum, head of the network, said in the statement. "The assertion of an energy emergency is a lie; a false narrative pedaled by Donald Trump as an excuse he can use to prolong continued use of aging energy operations like Eddystone, and to advance his demand that all federal agencies expedite approval of dirty fossil fuel operations in our region and nationwide.

"Proof of the lie is that while Donald Trump is perpetuating and fast tracking dirty fossil fuels, he is doing so in a way that disadvantages solar and wind projects which would provide for our region and nation's energy needs while at the same time protect communities from air pollution and environmental degradation and help protect present and future generations from the ravages of climate crisis," she said. ■

PJM Board Elects David Mills as Chair

By Devin Leith-Yessian

The PJM Board of Managers has elected David Mills to serve as its chair.

"It is an honor to lead this board at a time when continuity and stability are critical to our mission of preserving the reliability and affordability of the grid," Mills said in an *announcement* PJM published June 5. "Our stakeholders have made clear their desire to strengthen communication channels with the board, which we have already taken steps to accomplish. I look forward to working together to make the hard choices required of us to maintain the balance between electricity supply and demand."

He was elected to the board's chair-elect position in 2024, putting him in place to assume leadership if the prior chair, Mark Takahashi, left the role. Takahashi was not elected to another term on the Board of Managers during the May 12 Members Committee meeting and took his name out of the running before the vote was set to be reconsidered the following day. Mills was elected formally to be the board's chair on May 14.

PJM Board of Managers member David Mills, left, listens to Independent Market Monitor Joe Bowring speak during the October 2022 Organization of PJM States Inc. Annual Meeting. | © *RTO Insider*

"David is a very capable leader," PJM CEO Manu Asthana said in the announcement. "He understands the tradeoffs required to preserve reliability and affordability, and he has demonstrated his commitment to listening to and working in partnership with our stakeholders. I am confident that the reins of the PJM board are in able hands."

During the May 12-14 PJM Annual Meeting, Mills said he supports the board taking steps to improve communications with stakeholders. He said he would seek to add agenda items to future Members Committee meetings for attending board members to speak with stakeholders during the meeting, as well as for them to remain accessible after the meeting and wait until the following day to return home.

Mills first was elected to the board in 2021. He has chaired the Competitive Markets Committee and is a member of the Nominating Committee. Prior to joining the board, he served as Puget Sound Energy's chief strategy officer and previously worked for the Bonneville Power Administration. He earned a Bachelor of Science in economics from Portland State University. ■

PJM Proposes Changes to Determination of Jurisdiction over Generation

By Devin Leith-Yessian

PJM on June 3 *presented* a first read of a proposal to revise how it determines whether generation interconnections are subject to state or federal jurisdiction based on voltage or cost-recovery methodology.

The proposal would introduce a "bright-line test" that would designate generators interconnecting to facilities below 69 kV as being under state jurisdiction and thus required to obtain a wholesale market participation agreement (WMPA). Resources connecting to higher-voltage assets would be designated as under federal jurisdiction and required to obtain a generation interconnection agreement.

The proposal also includes a "backstop" where a point of interconnection could be classified as federal or state jurisdiction independent of the voltage depending on how the transmission owner, FERC or relevant electric retail regulatory authority has determined the cost-recovery paradigm.

Presenting to the Planning Committee, PJM Associate General Counsel Thomas DeVita said the aim of the proposal is to maximize the hours staff spend processing the more complicated studies needed on resources connecting to transmission assets while still maintaining visibility on distribution-level interconnections. He


PJM's Thomas DeVita speaks at the Planning Committee meeting June 3. | © *RTO Insider*

said it takes staff substantially longer to process a GIA application compared to a WMPA.

Under the status quo "first use" model for determining jurisdiction, the first resource interconnecting to a distribution facility for the purpose of participating in wholesale markets is classified as being under state jurisdiction and required to obtain a WMPA. All subsequent resources using that point of interconnection are considered "dual use" and considered under FERC jurisdiction. DeVita said PJM's model follows FERC's approval of an ISO-NE proposal to disclaim jurisdiction over all distributed energy resources. (See *FERC Approves Changes to ISO-NE DER Interconnection Process*.)

PJM Vice President of Planning Jason Connell said system impact studies for a generator pursuing a WMPA are completed by electric distribution companies rather than the RTO and produce a simpler agreement for it to process.

Exelon Director RTO Relations and Strategy Alex Stern said it makes sense to make improvements to the interconnection process that have been demonstrated to be beneficial in other RTOs and could carry benefits for developers as well.

"Developers interconnecting at the distribution level might have less responsibilities at the regional grid level and in fact avoid certain responsibilities entirely, which could perhaps be a benefit to them on top of less process with PJM," he said.

The proposal includes a dispute resolution process, beginning with the developer attempting to resolve issues directly with TOs and EDCs. If PJM determines a dispute involves its governing documents, the conflict could be arbitrated through the RTO's tariff-defined resolution process.

If granted by the commission, DeVita said PJM is planning a go-live date in 2026 and anticipates that the Planning Community online portal could be updated to allow members to select facilities and determine whether a generator interconnecting at that site would require a GIA or WMPA. ■

PJM TEAC Briefs

PJM Update on 2025 RTEP

PJM presented additional *detail* on the regional interchange and transmission violations that are expected to fuel need for transmission buildout in the first window of the 2025 Regional Transmission Expansion Plan (RTEP).

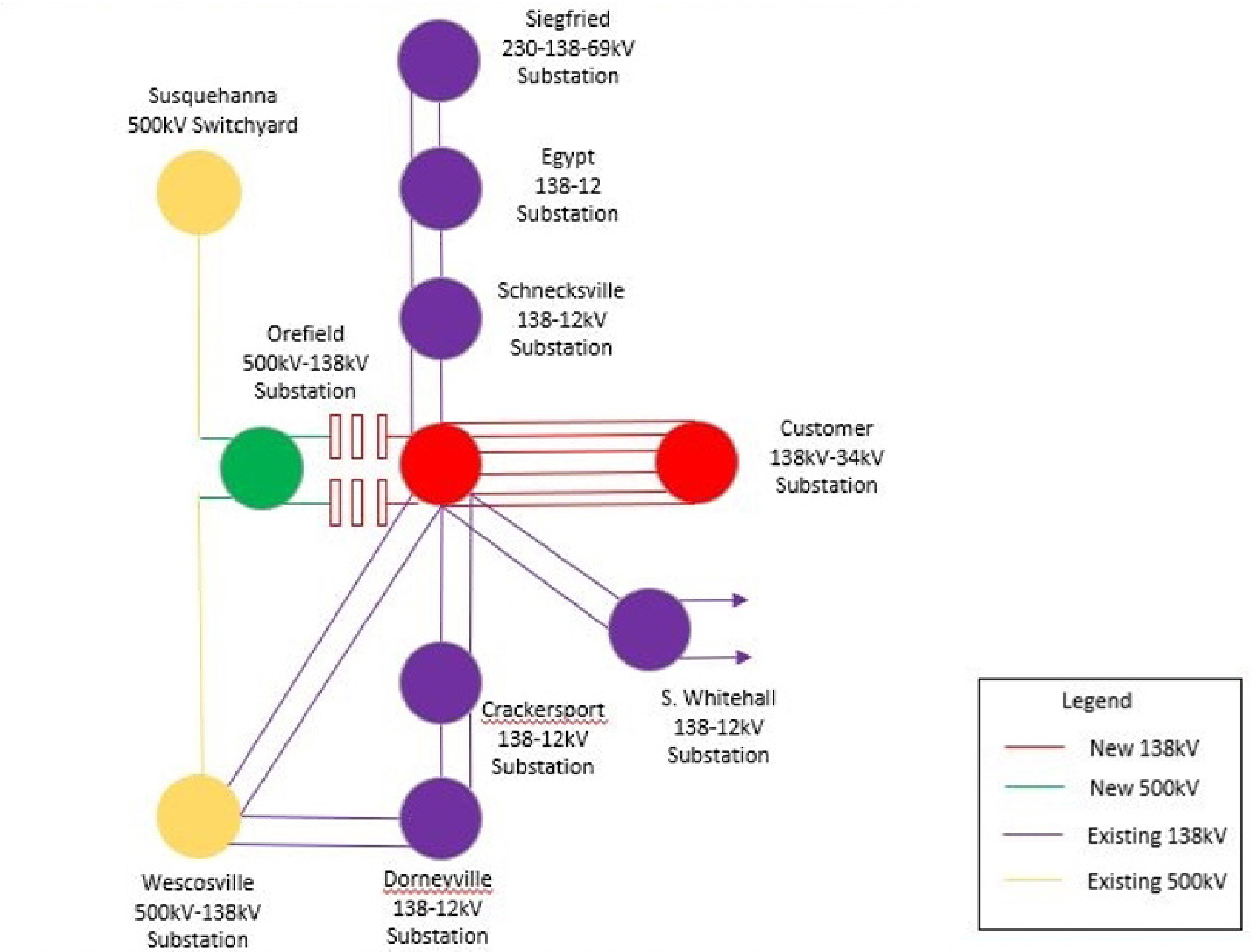
The competitive window for developers to submit projects addressing needs identified in Window 1 is set to open in mid-June and close in August.

Several large load additions have been submitted in the PPL region, while relatively little new generation is expected in the area, creating a need for new transmission to import power. The long-term seven-year case, which is used to right-size proposals brought for five-year needs, supports the conclusion that upgrades are needed to transfer energy between the Mid-Atlantic Area Council (MAAC) zone and PPL. Around 2.7 GW of load is expected near the Susquehanna switchyard by 2030, 1,400 MW near Juniata, 524 MW near Planebrook and 490 MW near Lancaster.

Large amounts of generation planned in the southern part of the Dominion zone are likely to require upgrades to the 500-kV backbone running through the region. Additional upgrades may also be required on the 765-kV corridor running from northwest PJM to the AEP zone depending on how generation comes online.

Generation studied through the fast lane interconnection queue (around 300 projects that had minimal network upgrades identified), the 2.6-GW Coastal Virginia Offshore Wind (CVOW) project and the 1-GW Chesterfield gas generator near Richmond, Va., are expected to serve local needs and not drive significant changes to regional power flows.

The five-year case looking at 2030 finds PJM's western region is expected to export almost 8 GW in the summer and 6 GW in the winter, down from the previous year in both seasons. Summer imports into MAAC would increase to around 3 GW. And while the region would remain an exporter in the winter, flows out were projected to decrease from 4 GW to 2 GW in 2030. Imports into Dominion would decrease in both seasons, falling from 6 GW to around 3.75 GW in the summer and from 10 GW to 6 GW in the winter.



PPL presented a $159 million supplemental project to serve a 1 GW load near Allentown, PA. | *PPL*

Supplemental Projects

PPL *presented* a $159 million project to serve a new customer near Allentown, Pa., which is expected to bring 1,000 MW of load by 2031. The project would construct a new 500/138-kV substation, named Orefield, which would cut into the 500-kV line between Susquehanna and Wescosville. The 138-kV Oreville switchyard would also cut into the Wescosville-Siegfried 138-kV and Wescosville-Allentown 138-kV lines. Six 138-kV lead lines would extend from the 138-kV switchyard to the 138/34-kV substation serving the customer. The project is in the conceptual phase with a projected in-service date of May 30, 2028.

The utility presented an additional $89 million project to serve a new customer near Harrisburg, Pa., requesting service for 450 MW coming online by 2030. A new 230-kV switchyard, named Highspire, would be constructed along the Steelton-Hummelstown 230-kV line, which would be rebuilt as a double circuit. Three 230-kV lead lines would run to a 230/34-kV customer substation. The Hummelstown 230-kV switchyard would be expanded with new 230-kV bays as part of the project. The proposal is in the conceptual phase with a projected in-service date of May 30, 2028.

PPL presented a $73.5 million project to serve a new customer near Jermyn, Pa., seeking to bring 500 MW of load online by 2029. A new 230-kV switchyard, named Callender Gap, would be built along the Lackawanna-Paupack 230-kV line and serve a new 230/34-kV customer substation with three 230-kV lead lines. The line segment between Lackawanna and Callender Gap would be upgraded to double circuit. The project is in the conceptual phase with an in-service date of May 30, 2028.

PECO *presented* a $27 million project to build the Forge Spring 230-kV substation to provide 50 MVA of capacity to the distribution grid in the King of Prussia, Pa., area. The new facility would cut into the Betzwood-Barbadoes line and feature eight 230-kV breakers. It is in the conceptual phase with a projected in-service date of Dec. 31, 2029.

Dominion *presented* a $108 million project in Virginia to create an additional 230-kV supply to the Elmont-Fredericksburg corridor, which is seeing a large number of substations constructed to serve data center load. An existing supplemental project is planned to rebuild the Kraken-Elmont 230-kV line, which will establish double circuit structures and a 115-kV corridor between Fredericksburg and Elmont. The new project would install 230-kV conductor on the double circuit structures between Elmont and Kraken and use open arms of existing structures from Elmont to Chickahominy. The result would be two new 230-kV circuits from Kraken to Chickahominy. The project is in the conceptual phase with a Dec. 31, 2030, in-service date.

Dominion presented a $32.3 million project to serve a data center customer in Spotsylvania, Va., planning to bring 108 MW of load by 2028. The project would construct the 230-kV Tributary substation by cutting into the New Post-Ladysmith CT 230-kV line with 2.4 miles of new double-circuit lines. The project is in the engineering phase with a projected in-service date of April 1, 2027. ■

— Devin Leith-Yessian

N.J. Advances Nuclear, Data Center Legislation

State Seeks to Prepare for Energy Shortfall, Ratepayer Burden

By Hugh R. Morley

New Jersey legislators have backed clean energy bills that include efforts to promote the development of small modular nuclear reactors and enable the state to better deal with data centers.

The Senate Environment and Energy Committee approved *S4423*, which would enable the Board of Public Utilities (BPU) to authorize site approval for a small modular reactor (SMR) in a municipality where a nuclear facility previously was located. The agency could supersede municipal and county decisions to authorize reactors able to generate 300 MW of power or less. The reactors would be licensed by the Nuclear Regulatory Commission, and nuclear fuel would be stored on-site.

In a separate vote, the full Senate on June 2 voted 38-0 in support of a third data center bill, *A5466*, which would direct the BPU to study the "effect of electricity usage by data centers on electricity rates in the state."

The bill, which goes to the governor's desk, would require the study to look at:

- Cost allocation, to determine if other electricity customers "unreasonably subsidize" the costs of data centers.
- Whether other customers incur "unreasonable rate increases" to support new transmission, distribution or generation facilities that serve data centers.
- Policy alternatives such as "the use of a special tariff to be applied to data centers, that could be used to mitigate or avoid rate increases caused by increased electricity demand by data centers."

Fixing an Energy Shortfall

The votes come as New Jersey, an importer of energy, searches for ways to boost its generating capacity. Demand for electricity is expected to rise dramatically over the next decade, fueled in part by the growth in electric vehicle use and the needs of data centers. PJM says its region, which includes New Jersey, faces an energy crunch because new generating sources aren't coming online as quickly as old, fossil-fueled sources are closing.

The nuclear and data center bills were among a slew of bills — including initiatives focused on storage, solar and geothermal energy — aimed at boosting the state's clean energy resources and curbing energy use.

Two bills moved by the Senate committee address the expected arrival of data centers, including those supporting artificial intelligence capability. The committee backed *S4293*, which would require the owner or operator of a data center to prepare an annual report to the BPU of the facility's water and electricity use.

The report also should include "basic information" on the facility and "performance calculations and indicators for the data center, including the energy reuse factor, power usage effectiveness, renewable energy factor and water usage effectiveness."

Opposing the bill, Ray Cantor, a lobbyist for the New Jersey Business and Industry Association, said the bill would needlessly add a burden to data centers that might consider coming to the state. State requirements already ensure water permits are not issued unless there is sufficient water, he said.

"From an energy perspective, these data centers are either bringing their own energy, or they're using energy off the grid, and that's all being accounted for," he said.

"On the one hand, we have policies in the state, and the governor has mentioned this as well, where we want business to come and locate here in New Jersey," he said. "And then [on] the other hand, we pass legislation like this, which, while it's not the end of the world from a regulatory perspective — it's just another thing that's being required. And it's another thing that's being required that doesn't need to be required."

Erecting Roadblocks

Cantor said he had similar concerns about another bill later backed by the committee, *S4307*. It aims to protect ratepayers from shouldering the burden of the development of generation systems that support data centers.

Why This Matters

Demand for electricity in New Jersey is expected to rise dramatically over the next decade. The state is an importer of energy and is searching for ways to boost its generating capacity.

The bill is designed to incentivize data centers to increase energy efficiency, including through the use of technologies that use the heat produced by the data center. In addition, it would require that the BPU review each application to ensure the data center creates and submits a tariff that demonstrates the facility's compliance with the law.

Cantor said enticing data centers to move into the state would be difficult if "we're continually putting roadblocks in the way or making it more expensive or problematic to develop here in New Jersey."

"We recognize that data centers are large energy users," he said. "But they're not the only large energy users. We have large manufacturing plants that use as much or more energy than data centers. Even hospitals could use more energy than a data center. And yet we don't single them out for special treatment."

Senate Environment and Energy Committee Chair Bob Smith said the bill "is absolutely a response" to a $20 hike in the average electricity bill that took effect June 1. State officials say the increase, set by the state's Basic Generation Services auction, was triggered in large part by PJM's capacity auction in July 2024, which included a massive jump in prices compared to the previous auction. PJM officials attributed the jump in part to high-demand data centers.

Doug O'Malley, director of Environment New Jersey, disputed Cantor's claim, saying data centers can be far larger than community institutions, using as much as 1 million gallons a day for cooling and electricity generation.

"We can't just rely on what we have right now. That's why this bill is so important," he said. "This is a reminder that we cannot have water hogs, (or) an energy hog, that literally spikes electricity rates (for) everybody."

The committee passed the bill with a 3-2 vote. The bill will go to the Senate Budget and Appropriations Committee.

Fixing an Energy Shortfall

In a separate vote, the Environment and Energy Committee voted 5-0 to back a bill, *S4100*, designed to simplify and speed up the process by which solar projects are permitted.

State officials say developing more solar is one of the quickest ways to address the pending electricity shortfall. But the bill says "New Jersey has the fifth-slowest-known solar permitting timelines of any state."

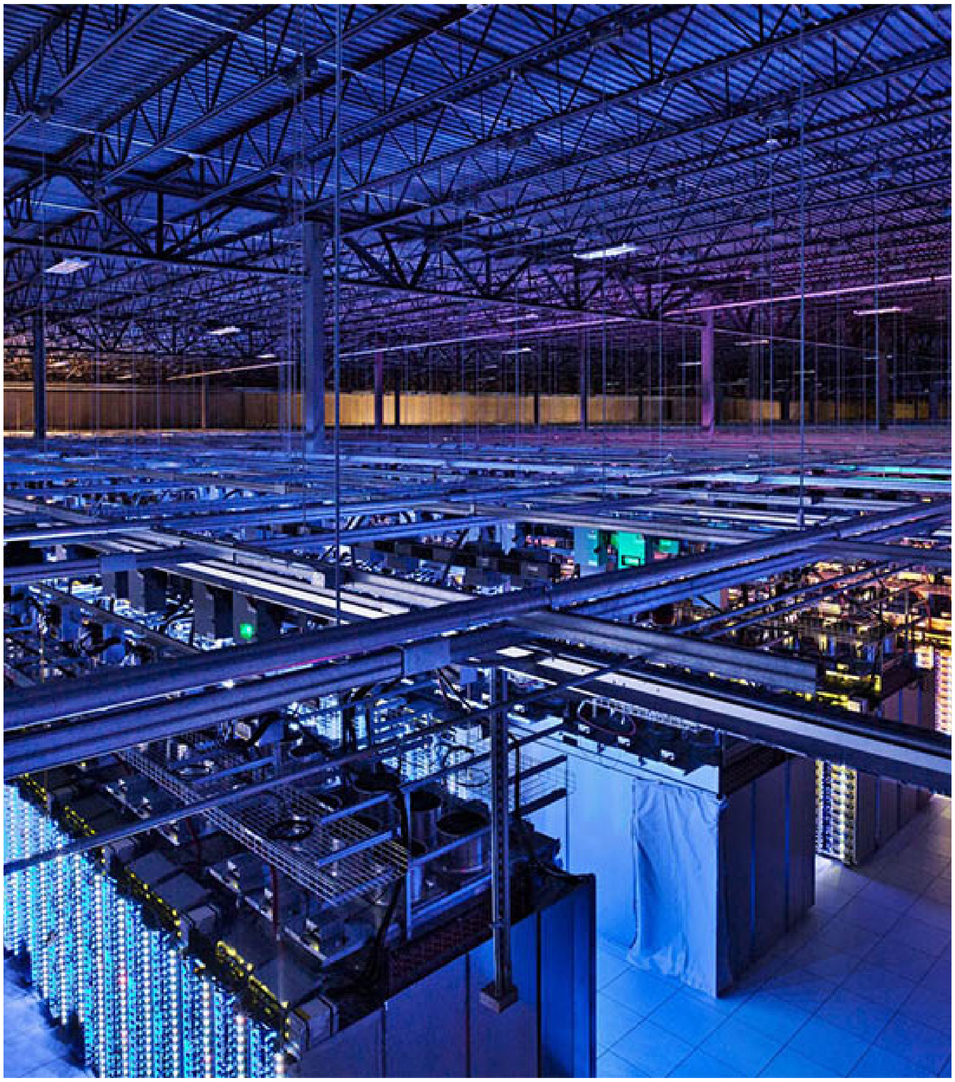
"Vestiges of outdated, overly bureaucratic permitting requirements" cause residents to "significantly delay installation efforts and significantly increase costs incurred in installing residential solar energy storage," the bill states.

Elowyn Corby, mid-Atlantic director for Vote Solar, in supporting the bill, told committee members that "local solar benefits our entire grid and society."

"While large-scale solar projects are important, they are often facing multiyear delays in the PJM interconnection queue," she said. "Local solar, on the other hand, can be rapidly deployed without these delays, addressing our immediate energy needs while giving us breathing room to bring large-scale renewables online."

To speed up the process, the bill calls for a State Smart Solar Permitting Platform that would automate permitting. It would enhance the ability of a local agency to review permit applications and permit revisions for safety and code compliance. The platform also would enable permitting agencies to release permits and permit revisions for residential solar energy systems, residential energy storage systems and main electric panel upgrades.

The state assembly backed a version of the bill, which goes to the Senate Budget and Appropriations Committee for consideration.



| Google

Storage and Geothermal

The Senate committee also backed a bill, *S4289*, that would authorize the BPU to procure and incentivize transmission-scale energy storage projects capable of storing at least 5 MW and connected with PJM.

Under the bill, the BPU would create an incentive program and then solicit applications for a tranche of projects. At its conclusion, the BPU would evaluate the impact on the sector, and, if needed, launch one or more tranches. The board's 3-2 vote sent the bill to the Senate Budget and Appropriations Committee.

Bob Gordon, a former BPU commissioner now representing a renewable energy company, argued that storage can save ratepayers money by providing energy to the grid at peak times. With the law in place, he said, New Jersey would have saved $100 million to $200 million in the coming year if the state had 500 MW to 1000 MW of transmission-connected battery storage.

"A state-led competitive-procurement program such as this will put New Jersey on the path to getting resources online and be able to provide the immediate benefits and cost relief for wholesale power costs to New Jersey," he said.

The committee backed by a 5-0 vote a bill, *S4424*, that would establish a three-year pilot program to replace aging or leaking natural gas pipelines with geothermal energy infrastructure.

The bill would enable gas utilities to submit plans to the BPU for review of the project size, scope and scale, and the expected benefits. The agency would assess the ratepayer impact and whether the benefits justify the cost. ■

PJM MIC Briefs

PJM Presents Education on Demand Response in Regulation Market

The PJM Market Implementation Committee on June 2 discussed a *proposal* to allow demand response resources to participate in the regulation market when there are energy injections at the same point of interconnection to the distribution grid. (See "Stakeholders Discuss DR Participation in Regulation Market," *PJM MIC Briefs: May 7, 2025*.)

PJM's Pete Langbein said curtailment service providers (CSPs) cannot participate in the regulation market during the same interval where there is either energy being injected at the same POI or no load is present unless the resource has entered into a wholesale market interconnection agreement. The proposal would allow DR to participate as a regulation-only resource so long as it has received authorization from the relevant electric distribution company and entered into a net energy metering (NEM) agreement.

The regulation-only resource would not receive energy-market compensation for injections onto the grid, and submeter performance and testing would be required.

Langbein said most regulation-only DR are customers with behind-the-meter storage that they want to offer into the regulation market without participating in the energy or capacity markets.

PJM's Ilyana Dropkin, chair of the Distributed Resources Subcommittee (DISRS), said the proposal is part of the RTO's Order 2222 compliance filing, but some subcommittee participants felt the 2028 implementation date is too far off and that it would be beneficial to effectuate this change sooner.

Amanda Rumsey, manager of RTO and federal regulatory policy for PPL Electric Utilities, said the company does have tariffs allowing net metering through state programs, but Pennsylvania law does not allow energy injections from storage to participate in an NEM agreement. She questioned whether the rule change could create situations where EDCs could be caught between state law requirements and the new market rules.

Langbein said the proposal would not override any state laws. If an EDC's NEM agreement prohibits this kind of arrangement in compliance with state laws, it would not be allowed.

3rd Phase of Hybrid Resource Rules Endorsed

Stakeholders endorsed by acclamation a set of manual *revisions* implementing the third phase of PJM's rules for hybrid resources. The changes conform with FERC's approval of PJM's overall ruleset (*ER25-1095*). (See "1st Read on 3rd Phase of Hybrid Resource Rules," *PJM MIC Briefs: May 7, 2025*.)

The revisions to Manuals 11, 27 and 28 expand the hybrid resource model to allow non-inverter-based generation at the same POI as battery storage to be combined into a single market unit. They also expand the language detailing how a hybrid resource with a capacity obligation meets its mandate to offer into the energy market.

The proposal would rewrite the definition of open-loop storage to allow generation owners to elect whether a battery capable of charging off the grid will be offered as open or closed loop. The status quo rules require storage capable of using PJM supply to charge to offer as open loop, but the RTO's Maria Belenky said there are instances in which generation owners may wish to operationally limit the storage to charge off the generation elements of the hybrid.

A generation-only hybrid would meet its energy must-offer requirement by submitting the forecast output, capped at the inverter capability, while a hybrid with a storage component should offer the "anticipated intermittent and battery output." The total amount of energy offered over the course of the day should be equal to or greater than the forecast intermittent output with a gross up of the battery efficiency. The resource owner can either use PJM's forecast or substitute their own so long as it meets PJM's requirements.

Revisions to the formula for lost opportunity cost credits would make storage and hybrid resources instructed to increase charging to mitigate transmission constraints or reliability issues eligible for credits. Resources instructed to reduce charging would not be eligible.

Elements of the phase 3 rules were also endorsed by the Planning Committee and Operating Committee on June 3.

2 Renewable Dispatch Packages Advance to MIC

PJM presented *education* on a pair of proposals aimed at improving how intermittent resources are dispatched ahead of a first read scheduled for the MIC's meeting July 9.

The proposals are aimed at making the data that PJM's security-constrained economic dispatch (SCED) relies on more accurate by tying resources' "effective Eco Max" parameter to PJM's forecast of their expected output. The parameter would be updated for every five-minute interval in real-time SCED, while hourly forecasts would be produced six days out.

PJM's Vijay Shah said SCED is limited to dispatching resources up to their Eco Max parameter, which can be lower than intermittent resources' real-time capability. The proposals would allow a forecast value to be used as the maximum dispatchable output instead.

The core distinction between the two proposals centers on whether curtailment flags should be available for wind and solar generation. Curtailment flags for all resources are set to be removed in July, though they were never available for solar generation, which would remain the target under PJM's proposal. A package introduced to the DISRS by Shell, American Electric Power, Dominion Energy and Gabel Associates would retain the flags for wind and establish new ones for solar. (See "Renewable Dispatch," *PJM MRC Briefs: April 26, 2023*.)

A nonbinding poll at the DISRS found 96% support for the stakeholder package, while PJM's received 15% support. The threshold for a subcommittee poll to indicate support for a proposal requires three members from at least two sectors to be in favor, which was surpassed for both packages.

Shah said eliminating curtailment flags would require generation owners to follow their basepoints and avoid situations where intermittent resources with low marginal costs are curtailed because their bid-in parameters are lower than actual output, resulting in higher cost units being committed. ■

— Devin Leith-Yessian

PJM Operating Committee Briefs

Monthly Operating Metrics

The month of May saw one spin event to PJM, a shared reserve event, three high-system-voltage actions and 24 post-contingency local load relief warnings, according to the RTO's monthly operating *metrics*.

The hourly forecast error rate was below the 25-month average at 1.31%, with the average peak forecast off by 1.45%.

A thunderstorm May 16 caused the peak load to be 4.84% lower than expected, which carried into the next day when lower-than-expected temperatures corresponded with a 4.74% overforecast peak load, PJM's Marcus Smith said. Memorial Day was also overforecast by 4.19%, which was attributed to the holiday being the coldest in four years. Lower temperatures also contributed to a 3.21% overforecast on May 29. High afternoon temperatures on May 11 led to a 3.29% underforecast.

A spin event was initiated on May 19 with 2,641 MW of generation and 688 MW of demand response assigned, of which 1,679 MW and 474 MW, respectively, responded. The event lasted seven minutes and 31 seconds, meaning it does not count toward the rolling average of reserve performance PJM is using to determine when it should scale back a 30% adder on the synchronized and primary reserve requirement.

Only reserve deployments longer than 10 minutes contribute to the average, which would result in the adder being reduced if performance across three events average is above 75%. Thus far, only one event since the deployment of automatic generation control (AGC) has qualified, an event on Feb. 5 that lasted 10 minutes and three seconds and had a 65% response rate.

PJM Presents Cold Weather Preparations

PJM will be *updating* Markets Gateway with a field for owners of gas generators to indicate whether they foresee any issues with procuring fuel during extreme cold weather as part of the RTO's compliance with NERC's TOP-002-5 standard for operations planning.

The standard was updated to add a new requirement for balancing authorities to show how they will prepare for winter storms, with enforcement beginning on Oct. 1.

The additional field in Markets Gateway can be filled out at any time, but it becomes mandatory during cold weather advisories and alerts. Additional detail about the change will be presented to the Electric Gas Coordination Subcommittee, which is scheduled to next meet on June 12.

Manual Revisions Endorsed

The committee endorsed *revisions* to Manuals 10 and 14D to reflect the third phase of PJM's rules for hybrid resources. The changes include expanding the hybrid model to apply to non-inverter-based generation paired with storage or inverter-based resources, as well as allowing market sellers to choose whether to offer storage as open-loop or closed-loop.

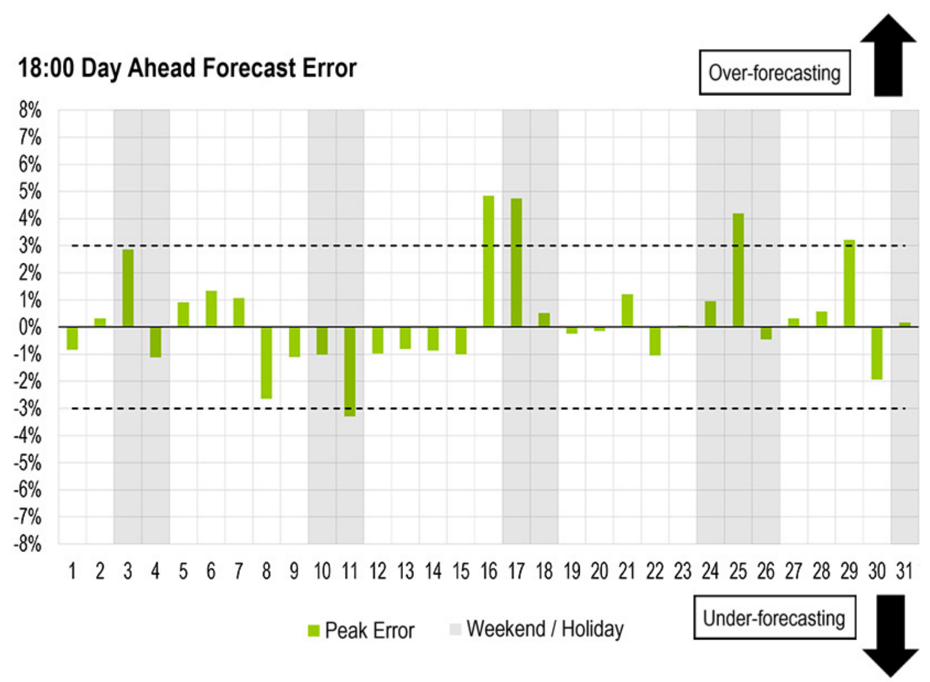
The package includes changing language to be more reflective of the wider combinations of generation types that could be classified as hybrid under the proposal. For instances where storage is capable of charging from the grid, the resource owner would be permitted to choose whether to offer it as open- or closed-loop, allowing for situations where a battery is physically capable of charging but the owner has determined not to operate it in that fashion.

Any non-inverter components of a hybrid should report their output into eDART as their installed capacity, measured as committed and available megawatts.

Stakeholders also endorsed revisions to Manual 12: Balancing Operations drafted through the document's periodic review. The language includes updates to the operating mode change procedure to detail how dispatchers will coordinate with transmission owners and load-serving entities when redispatching generation or switching between on- and off-cost modes. The proposal also requires market sellers with self-scheduled units to call the PJM master coordinator when seeking to change output if NERC tags cannot be processed.

The manual revisions include a change to require intermittent or inverter-based hybrid resources to set their emergency minimum to zero, while non-inverter-based hybrids would be required to set their minimum to the economic minimum parameter for the non-inverter component. The changes conform with FERC's approval of PJM's hybrid resource rules. ■

— Devin Leith-Yessian



PJM saw five days exceed its 3% forecast error benchmark in May. | *PJM*

SPP, Hitachi Partner to Use AI in Clearing GI Queue

By Tom Kleckner

SPP and Hitachi have announced a strategic partnership to produce an integrated AI-based solution they say will reduce study-analysis times by 80% in the generator interconnection process, potentially resolving one of the key issues that has slowed the grid's ability to meet escalating demand.

The companies said in a June 5 *press release* that end-to-end use of industrial AI and advanced computing infrastructure will help significantly speed up safe integration and use of additional resources supporting the central U.S. grid.

The U.S. Energy Information Administration *said* in January that the nation's electricity consumption grew by 2% in 2024 and will continue to grow at that rate in 2025 and 2026. It will be the first three years of consecutive growth since 2005 to 2007, with much of the demand coming from battery manufacturing operations and data center consumption.

"Our nation's demand for electricity has risen sharply in recent years following a long period of slow growth. Our industry has struggled to keep up with this sudden and significant shift," SPP CEO Lanny Nickell said.

"There are a lot of would-be power producers out there waiting to connect to the grid, but yesterday's systems and technology haven't been sufficient to enable us to bring incremental capacity online fast enough. It's time to fix that," he added.

The grid operator's *GI queue* currently includes 679 projects, 380 of which are active, and more than 161 GW of capacity. It still is working on study clusters that date back to 2018.

The integrated solution comprises multiple Hitachi capabilities that include an AI-based power simulation algorithm, accelerated calculations, augmented simulation modeling, predictive analytics, and design and engineering services.

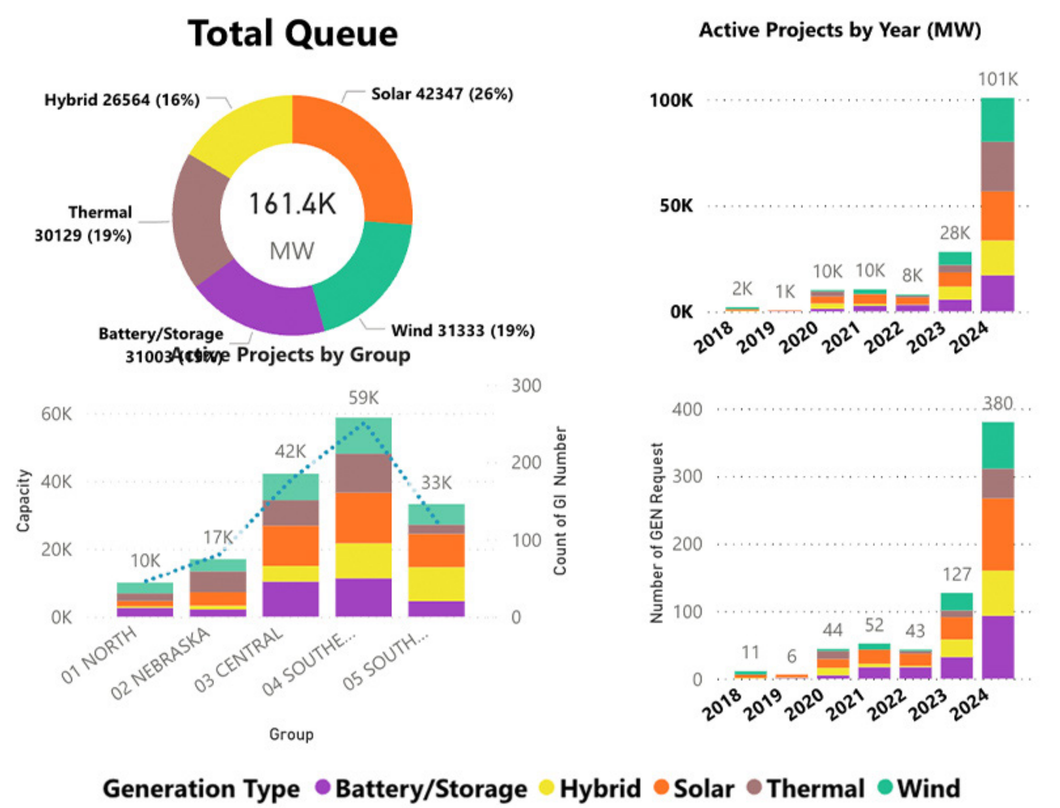
Hitachi said the partnership intends to "reimagine" the electric sectors production and distribution process through "the lens of modern AI technology." SPP then can make "significantly quicker, better-informed decisions," said Frank Antonysamy, Hitachi Digital's chief growth officer.

"Real-time data access is needed to create truly realistic scenarios caused by new generator introductions. The AI solution we're all developing will provide that data, among other advantages," Antonysamy said.

Along with NVIDIA, another AI provider, Hitachi and SPP will draw on Hitachi's various competencies, including an integrated storage and computing platform built on NVIDIA accelerated computing, networking and AI software. The AI-driven technologies will be applied to process automation, predictive analysis, communication systems integration and other study areas.

The project's first phase is expected to be completed by December 2025. The phase includes initial systems acceleration, data-management processes optimization and introducing AI-augmented simulation modeling.

SPP says as an RTO, it will guide the integration of technical solutions and services and ensure the project outcomes align with industry requirements and regulations. Later objectives will address alternative energy integration challenges and transmission constraints. ■



SPP's interconnection queue has expanded exponentially in the last few years. | *SPP*

Why This Matters

SPP and Hitachi say their partnership potentially could help resolve one of the key issues slowing the grid's ability to meet escalating demand. Using yesterday's systems and technology haven't been sufficient to bring new capacity online fast enough, SPP's CEO says.

MISO-SPP JTIQ Fed Funds Caught Up in DOE Review of Grants

Funding Would Provide Nearly $465M for Joint Projects Between the RTOs

By Tom Kleckner

The U.S. Department of Energy is preparing a case-by-case review of all the agency's financial assistance awards under the Biden administration that it says could have "significant ramifications" for current and prospective recipients.

That review includes a $464.5 million grant to MISO and SPP under DOE's Grid Resilience and Innovation Partnerships (GRIP) program.

The grant, the largest awarded by DOE, would offset about 25% of the capital cost for five projects in the RTOs' $1.6 billion Joint Targeted Interconnection Queue (JTIQ) portfolio. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

A spokesperson for the Minnesota Department of Commerce said all GRIP funds are subject to the process review. Grant applicants face a June 16 deadline to provide the requested data to DOE, said Kristen Glazer, Commerce's assistant communications director. The department is the lead applicant on the project, which also involves the Great Plains Institute, along with the two RTOs.

MISO and SPP both told *RTO Insider* they are coordinating with each other and the other JTIQ partners to respond to the data request. Minnesota said it has not been given a "definitive timeline" by DOE for the review's completion.

"In the meantime, we remain confident in the value of the proposed projects," SPP spokesperson Derek Wingfield said.

Grid United's Michael Skelly (left) listens as ALLETE CEO Beth Owen discusses transmission issues during the EEI annual meeting. | © *RTO Insider*

MISO told stakeholders earlier in 2025 that DOE had not indicated that GRIP funding is in jeopardy. It said the JTIQ portfolio "is not contingent upon the receipt of GRIP funding."

The grid operators say the five 345-kV JTIQ projects will enable the interconnection of "tens of thousands of MW of new generation" on their seam to serve new data centers and other large loads.

The GRIP funds were awarded in 2023, but no funds have been disbursed.

DOE announced the review process in a May *press release*. It requested additional information to evaluate 179 awards covering more than $15 billion in financial assistance. The agency said it is prioritizing "large-scale commercial projects" that require more detailed information from the awardees in a process that could extend to other DOE program offices.

Energy Secretary Chris Wright said agency staff had spent 110 days reviewing "billions of dollars that were rushed out the door, particularly in the final days of the Biden administration" that it found concerning. He said agency staff would ensure due diligence to use "taxpayer dollars to generate the largest possible benefit to the American people."

"Any reputable business would have a process in place for evaluating spending and investments before money goes out the door, and the American people deserve no less from their federal government," Wright said.

DOE is requiring recipients to provide written responses and supporting documentation and to cooperate with program personnel on any follow-up requests. Projects that meet the agency's standards will proceed, but those that don't will be modified or terminated, based on the department's outcome.

"It feels like they're going to use that process to down-select, including projects that were awarded but maybe not contracted," Grid United CEO Michael Skelly said during the Edison Electric Institute's annual meeting in June. "It's not totally clear what's happening there, but the one kind of wild card is there's a real interest in moving quickly because they get the imperative around load growth and the need to build things."

Why This Matters

The $464.5 million from DOE for the MISO-SPP Joint Targeted Interconnection Queue would offset about 25% of the capital cost for the five projects in the $1.6 billion portfolio.

Sitting next to Skelly on the EEI panel, ALLETE CEO Beth Owen said her organization operates an *HVDC modernization project* that is relying on federal and state support. She said ALLETE is attempting to make the case with the federal government that the granted dollars need to flow.

"We've spent a lot of time with the administration helping explain why these projects are important and why the DOE grant is an important part for customers," Owen said. "This is an existing project that's being modernized that will help ensure reliability and energy security. We've been using all of the things that we know are important to this administration. … In a high inflationary environment, those dollars are going to be critical to this project for those reasons."

FERC in November 2024 approved tariff revisions and modifications to the joint operating agreement between MISO and SPP that enshrine a structural and cost-allocation framework for the JTIQ projects. Their novel approach to joint planning focused on backbone projects they say will unlock 28 GW of capacity and reduce curtailments in a highly congested region. (See *FERC Approves JTIQ Framework, Cost Allocation*.) ■

Amanda Durish Cook contributed to this article.

Company Briefs

Qcells Expands into Solar Panel Recycling Business

Qcells last week announced the launch of EcoRecycle and its first recycling operation planned for Cartersville, Ga.

At full capacity, EcoRecycle's facility will have the ability to recycle approximately 250 MW of solar panels annually, or approximately 500,000 panels per year. The facility will remove aluminum, glass, silver and copper from used modules and process them for reuse.

More: *pv magazine*

Sunnova Energy Lays off 718 Employees

Sunnova Energy laid off 718 employees, or 55% of its workforce, on May 30 in a bid to slash costs as one of its subsidiaries files for bankruptcy.

The wholly owned subsidiary, Sunnova TEP Developer, filed for Chapter 11 bankruptcy. However, Sunnova said the bankruptcy filing "is not expected to have a material effect on our servicing operations for existing customers."

More: *Houston Chronicle*

Battery Cell Maker Pauses Construction of SC Plant

Battery cell maker Envision Automotive Energy Supply Co. (AESC) last week announced it is pausing construction work on its manufacturing plant in South Carolina.

The company said it is pausing construction due to "policy and market uncertainty" but "fully intends to meet our commitments to invest $1.6 billion and create 1,600 jobs in the coming years." It did not indicate what the new timeline might be.

AESC's pause comes four months after the company pulled back on earlier plans to expand the plant beyond its original scope.

More: *South Carolina Daily Gazette*

Transco Reapplies for Northeast Natural Gas Pipeline

Transcontinental Gas Pipe Line (Transco), citing executive orders signed by President Donald Trump, last week applied to FERC for the reissuance of permission to construct and operate the Northeast Supply Enhancement project.

FERC's permission for Transco to undertake the project lapsed about a year ago after both the New Jersey Department of Environmental Protection and the New York State Department of Environmental Conservation denied the necessary permits. Transco, which has not made any changes to its plan, has asked FERC to reauthorize the project by Aug. 29 so it can begin construction by the end of the year.

The project calls for about 23 miles of a natural gas pipeline that would pass through central New Jersey and under Raritan Bay to Long Island.

More: *MyCentralJersey*

Federal Briefs

TVA to Build Solar Field in Kentucky

The Tennessee Valley Authority last week announced plans to build a large-scale solar field on a closed coal ash site in McCracken County, Ky.

The project, called Project Phoenix, will feature 240,000 solar panels that can generate 100 MW.

TVA expects the site to support the company's goal of becoming 80% carbon free by 2035.

More: *The Paducah Sun*

EPA Down At Least 733 Staffers Since January

EPA is down more than 700 career staffers so far this year, the agency last week.

An agency spokesperson said as of Jan. 1, it had 17,080 staffers, while as of May 30, it had 16,347 — a loss of 733 people. Staffers still on the agency's payroll but are on leave — either because they opted to take the "fork in the road" buyout or they are probationary workers whose fates are pending in court — are counted as still being on staff.

More: *The Hill*

BLM Seeks Public Input on Redonda Solar Project

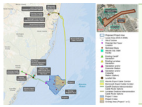
The Bureau of Land Management is seeking public comment on the proposed Redonda solar project in Riverside County, Calif.

If approved, the project could produce and store up to 250 MW.

The public comment period will close on July 1.

More: *BLM*

Mid-Atlantic news from our other channels



Developer Shelves Atlantic Shores, Seeks to Cancel ORECs

NetZero Insider

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

State Briefs

ARKANSAS

Newton Becomes 5th County to Ban Wind Farms

The Newton County Quorum Court last week voted 5-1 to pass an emergency ordinance banning the construction of any commercial wind or solar farms in the county for the remainder of the year.

The court can lift the moratorium before the end of the year if it chooses to.

More: *Northwest Arkansas Democrat Gazette*

CALIFORNIA

Air Board Rejects Rules Phasing Out Gas-powered Heaters in LA Basin

The South Coast Air Quality Management District board last week voted 7-5 to reject measures that would have phased out residential gas-powered water heaters and furnaces in the Los Angeles basin.

The two rules would have set increasing targets for sales of zero-emission products in Los Angeles, Orange, Riverside and San Bernardino counties over the next decade. The targets would not have been mandatory, although manufacturers would pay fees for each natural gas water heater or furnace sold.

The board also voted 7-4 to send the two proposed rules back to a committee, which means any new version likely won't be considered until next year.

More: *CalMatters*

CONNECTICUT

House Passes Bill Offering Relief for Utility Customers

The House of Representatives last week voted 144-3 to pass legislation promising relief for utility customers saddled with some of the highest electric costs in the U.S.

Legislators claimed the bill will immediately offer savings of 1 or 2 cents/kWh off current rates. For most residential customers, that would equate to more than $100 a year. However, the bill also has a steep reduction in incentives for renewable sources and reduces the number of renewable credits suppliers must purchase on behalf of customers over each of the next five years.

The bill now heads to Gov. Ned Lamont, who said he planned to sign it.

More: *CT Mirror*

FLORIDA

PSC Approves Duke's Cost Recovery for Solar Projects

The Public Service Commission last week approved a solar power rate adjustment for Duke Energy to recover costs for four solar centers.

The decision will provide cost recovery for the first phase of a larger plan involving four projects that add about 300 MW of solar generation. Those projects involve the Sundance project in Madison County, Rattler in Hernando County, Half Moon in Sumter County and Bailey Mill in Jefferson County. Each will account for 74.9 MW.

More: *Florida Politics*

HAWAII

HECO Files Wildfire Safety Plan with PUC

Hawaiian Electric (HECO) last week filed a three-year, $350 million contract with the Public Utilities Commission to reduce the risk of future wildfires.

HECO said $180 million will be spent solely on Maui, which has the highest fire risk.

If approved, monthly bills are expected to increase by $5 for Maui County residents, $3 for Hawaii Island and $1 for Oahu.

More: *HawaiiNewsNow*

MICHIGAN

Consumers Energy Seeks $436M Rate Increase

Consumers Energy last week asked the Public Service Commission for a $436 million rate increase — its largest in the last 20 years.

Consumers said the increase is necessary to continue fulfilling its "reliability roadmap" and would increase monthly bills by 13% for residential customers.

State law prohibits utilities from filing new rate requests more frequently than once every 12 months. Consumers' latest application came 367 days after its last one — the first business day after the one-year clock reset. It will be the sixth year in a row Consumers has sought a rate increase.

Consumers is also seeking permission to implement an additional $24 million surcharge for spending deferred during a previous rate case.

More: *MLive*

OKLAHOMA

OCC Approves PSO's Acquisition of Green Country Plant

The Corporation Commission last week approved the Public Service Company of Oklahoma's purchase of the Green Country Power Plant.

The plant is a 795-MW natural gas-fired facility located in Jenks.

The acquisition is set to be finalized by July 2025.

More: *AEP*

OREGON

Legislature Passes 'POWER Act,' Targeting Industrial Energy Users

The state House of Representatives last week voted to pass the POWER Act, and it will now head to Gov. Tina Kotek's desk.

The bill creates a new classification for data centers, cryptocurrency and other large industrial energy users using more than 20 MW to pay for their share of electricity use and costs. It also requires large energy users to sign a 10-year contract that commits them to pay a minimum amount for energy used as well as pay for adding new transmission.

According to Oregon Citizens' Utility Board, large industrial users pay about 8 cents/kWh, while residential customers in the same PGE system pay close to 20 cents/kWh.

More: *OPB*