ISSN 2377-8016 : Volume 2025/Issue 26 ▪ July 1, 2025

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ IESO ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

FERC/FEDERAL

Renewables Supporters Decry Late Change to Trump's 'Big Beautiful Bill'

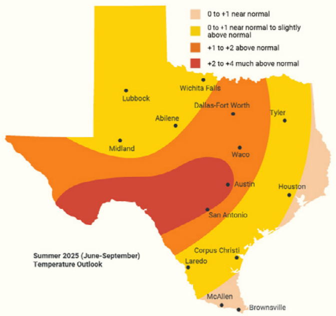
Shutterstock

Renewable energy supporters contend newly introduced taxes in the One Big Beautiful Bill Act — Republicans' budget reconciliation bill — would strand hundreds of billions of dollars in investment, threaten energy security and undermine domestic manufacturing. Senators worked on the bill over the weekend and began a "vote-a-rama" on amendments Monday that continues as of press time. Republicans hope for final passage today, but some GOP senators want to moderate the energy-related language.

CONTINUED ON P.3

Grid on Red Alert as Heat Wave Sweeps U.S.

Max Gen Warnings and Local Outages, but No Load Shed



ERCOT

RTOs put generators on alert last week as a heat dome settled over much of the U.S. While reserve margins were tight as record-high temperatures produced record-high peak loads in some regions, and the heat caused local distribution outages, reliability was maintained.

MISO

© RTO Insider

MARC Confronts Public Perception, Affordability, 'Post-DEI' and Nuclear Options (p.25)

It wouldn't be an annual state regulatory conference without a discussion on load forecasts, but MARC 2025 also featured a diverse slate of topics.

RTO Insider
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

In this week's issue

Correction:

An article in last week's newsletter, *Order to Keep Campbell Plant Running Challenged at DOE and FERC*, implied that there was an error regarding MISO's risk level in NERC's Summer Reliability Assessment. The error was actually in NERC's Long-Term Reliability Assessment, not the summer assessment report. The article has been corrected online.

Renewables Supporters Decry Late Change to Trump's 'Big Beautiful Bill'

Proposed Foreign Components Tax Could Hinder Completion of Existing Projects

By James Downing

Senators working through the weekend on the One Big Beautiful Bill Act — Republicans' budget reconciliation bill — delivered renewable energy supporters an unexpected and unpleasant surprise in the form of proposed taxes that would likely stymie completion of projects already in the works.

While the electricity industry already expected cuts to energy tax credits, changes to the *bill* released over the June 28-29 weekend just before it went to the floor added a new tax on energy projects that rely on foreign components.

"With no warning, the Senate has proposed new language that would increase taxes on domestic energy production," American Clean Power Association CEO Jason Grumet said in a statement. "In what can only be described as 'midnight dumping,' the Senate has proposed a punitive tax hike targeting the fastest-growing sectors of our energy industry. It is astounding that the Senate would intentionally raise prices on consumers rather than encouraging economic growth and addressing the affordability crisis facing American households."

The new taxes would strand hundreds of billions of dollars in investment, threaten energy security and undermine domestic manufacturing, Grumet added.

While changes to energy tax credits were an inevitable part of the legislation, American Council on Renewable Energy CEO Ray Long said, the industry had tried to come to reasonable accommodation that would allow current projects to be completed.

"To be clear, the Senate language effectively takes both wind and solar electric supply off the table, at a time when there is $300 billion of investments underway, and this generation is among the only source of electricity that will help to reduce costs and keep the lights on through the early 2030s," Long said in a statement. "Along with battery storage and natural gas, wind and solar are the only sources of electricity that can be built in time to meet our increasing thirst for more electricity. Taking these off the table not only increases costs and ensures supply shortages, it also ensures thousands of layoffs and factory closures."

| Shutterstock

Why This Matters

Renewable energy supporters contend the new taxes would strand hundreds of billions of dollars in investment, threaten energy security and undermine domestic manufacturing.

The U.S. Chamber of Commerce generally supports the bill, but even its chief policy officer, Neil Bradley, posted on *X* that "taxing energy production is never good policy" and urged Congress to remove the tax from the final bill to avoid higher power prices.

An *amendment* from Sens. Joni Ernst (R-Iowa), Chuck Grassley (R-Iowa) and Lisa Murkowski (R-Alaska) would moderate some of the language around energy tax credits while still phasing them out for any project that starts construction after 2027.

"This amendment would provide a more workable transition for energy businesses while protecting energy sector jobs and projects currently in the pipeline," Lisa Jacobson, president of the Business Council for Sustainable Energy, said in a statement. "Clear, predictable and long-term tax policy is essential for market confidence that will get projects deployed quickly and urgently as America faces skyrocketing energy demand. Companies plan with these tax incentives in mind and rely upon them for capital allocation, planning and project commitments — all of which will be jeopardized by abrupt cut offs or additional restrictions." ■

Future of Transmission Planning and Policy in Focus at Infocast Summit

By James Downing

ARLINGTON, Va. — While much of the energy industry is focused on the latest news on the reconciliation budget bill and its cuts to tax credits, the transmission sector is not — because it was left out of the Inflation Reduction Act.

"This, to me, was a flaw with the original Inflation Reduction Act," Grid Strategies President Rob Gramlich said at Infocast's Transmission and Interconnection Summit on June 25. "They really didn't do much transmission; it was sort of overlooked."

The Democrats passed the IRA using reconciliation, a process that allows the Senate to vote on items related to the budget without the threat of a filibuster, in 2022. With control of the White House and Congress, Republicans now are using the same process for their so-called One Big Beautiful Bill that includes cuts to many tax credits and programs from the IRA.

In between these two major bills, bipartisan permitting legislation did make it out of the Senate Energy and Natural Resources Committee in 2024 but never was brought to the floor. Permitting legislation should get another chance, but Gramlich said it will have to wait.

"Basically, you can't do big permitting reform in a reconciliation/budget bill," Gramlich said. "But they did have to try, because if you're a Republican member of Congress, why would you not try that first and see what you can get that way? And also, why would you not try to do everything you can try to do with executive action?"

Why This Matters

Transmission expansion is needed to meet growing demand in a reliable and affordable manner, and the conference looked into the industry's efforts.

From left: Zero-Emission Grid CEO Mike Tabrizi, Grid Strategies President Rob Gramlich, MWR Strategies' Michael McKenna, ITC Holdings' Devin McMackin and Grid United President Kris Zadlo | © RTO Insider

The budget bill is likely to take up most of Congress' time over the next month, but once it is back in session this fall, Gramlich expects permitting will be taken up again.

Energy Secretary Chris Wright has said he hoped transmission could get similar treatment to natural gas pipelines, which shows some in the Trump administration support changes, MWR Strategies President Michael McKenna said. Support for changing permitting laws is growing on both sides of the aisle.

"The Republicans are going to find it much easier to live with if President Trump is still president, so I think the sweet spot is going to be starting in about eight or 10 months and going until the end of the Trump presidency," McKenna said.

While the industry waits to see if Congress can pass a permitting bill, it's implementing major changes from FERC: Order 1920 on planning and cost allocation, and Order 2023 on interconnection queues.

Some of the regions already have rules in place that have led to significant regional transmission being built under the regimes in compliance with Order 1000. MISO and SPP have different markets, but both have transmission planning processes with significant buy-in from the states in their two large footprints, ITC Holdings Director of Federal Affairs Devin McMackin said.

"So hopefully, for us at least, that means it's not going to be a particularly arduous process to implement the order, and we'll kind of basically see some repetition of the continuous planning efforts that we already have," McMackin said. "So, I'm fairly optimistic that the concepts that underlie 1920 in many cases are already in place."

The cluster study approach in Order 2023 was adopted in some markets before FERC started working on the rule, and more utilities adopted it while the order was pending, Gramlich said.

"But that doesn't mean it didn't have an impact: That three-year process really led everybody to that outcome, and that's helpful," Gramlich said. "It doesn't mean that's the end of the reforms or the process either. It just means that it's kind of herding all the cats in that general direction."

Regional Differences

FERC left certain details in implementing the orders up to the different regions, so their choices will have an impact on how much transmission planning is reformed by its recent orders, Zero-Emission Grid CEO Mike Tabrizi said. Sometimes transmission planning can become a standardized process where not much gets done, especially when it comes to meeting the minimum of maintaining compliance with NERC standards, he said.

"What happens is, every year they go through this compliance process because they are so overloaded with so many other tasks that they have on their hand," Tabrizi said. "The goal is not to actually plan the system; the goal is actually to check the boxes for the compliance."

Grid United President Kris Zadlo said Order 1920 did not seem like a big deal to him the first time he read it because it was standard operating practice when he joined the industry during a time of high load growth.

"Over the last 25 years, we've had essentially flat load growth in the United States, and it allowed us to be essentially reactive," Zadlo said. "Like I would say, for the last two decades, we haven't been doing transmission planning. Transmission planning means you're planning for the future. You're not reacting."

The industry had seen such huge load growth in the 1960s and '70s that it overbuilt the system, and that allowed planners to be reactive for longer than the lack of load growth on its own, Zadlo said.

"We didn't inherit an industry that had strong regional institutions that were charged with infrastructure planning," Gramlich said. "RTOs, in any case, are 25 years old. That wasn't their original focus for the reasons we've described. It was more about markets."

FERC's regional transmission plan applies to RTO footprints, but it also applies to utilities outside of them that have formed regions like WestConnect, which covers parts of the Southwest. While it has held meetings over the years, it hasn't selected a transmission project for the entire region, New Mexico Public Regulation Commissioner Gabriel Aguilera said.

"They've never selected a regional transmission project since its inception in" 2002, Aguilera said. "And I don't know if that is a little bit shocking to any of you; it's a little bit shocking to me that there were no regional transmission needs identified. And, so, there is some work to do there, clearly."

Order 1920 has caused the states in the West to look at regional transmission planning again, with more diverse stakeholders, including state regulators, getting involved than in the WestConnect process, which Aguilera said has been dominated by incumbent utilities and some independent transmission developers.

Every region of the country could use more transmission capacity for various reasons, and the West is no different, though things have been changing significantly there in recent years, said former FERC Chair Richard Glick, now a consultant at GQ New Energy Strategies.

The Northwest used to think it could rely on cheap and plentiful hydropower, but recent years have made clear it needs more access to imports from other parts of the Western Interconnection, Glick said.

"The Southwest, for instance, could bring in more power from the Northwest," Glick said. "The problem is that the grid in the West is becoming increasingly congested. It's more difficult to engage in those transactions, certainly at an economic level. So, there certainly is a growing recognition that transmission is needed."

Order 1920 requires more anticipatory planning, so that should force all regions to improve their planning processes, but it's an open question on how much regional transmission will get built, Glick said. The region faces unique issues like huge, non-FERC-jurisdictional utilities that have to opt into planning processes and cost allocation.

"Transmission planning regions cannot plan for the needs of the non-jurisdictional utilities unless those non-jurisdictional utilities volunteer to pay whatever is allocated in the cost allocation process," Glick said. "And the odds of that happening are obviously very small."

Load Growth

The return of load growth, caused by very high computing demand from data centers for artificial intelligence and other applications, was not known to FERC when Glick launched the rulemaking process that led to Order 1920, but it has changed the discussion around its implementation.

ELCON CEO Karen Onaran represents traditional industrial customers who also contribute to demand growth, but the hyperscale data centers have demoted her members from large load to "middle load," she joked. A key policy goal of manufacturers is to keep the price of energy down because that makes their products more competitive.

"Over the past year [to] year-and-a-half, one of my major focuses is going around the country and talking to state-level manufacturers … who have been fighting against transmission for a long, long time and changing that narrative of it to say, 'Yes, transmission is expensive, but not having transmission is even more expensive,'" Onaran said.

Order 1920's shift to 20-year plans instead of 10 is well suited to the return to demand growth, Con Edison Transmission CEO Stuart Nachmias said.

"I think 10 years have been sort of the norm," he added. "I think looking at longer before we had growing demands and growing needs were sort of pushed off as a little bit too theoretical. We don't really know what's going to happen, but now we really know that there is load and there are needs, and we can look out further."

While the order faces some legal challenges, including the question of whether FERC can force transmission owners to file cost allocation agreements struck by states they disagree with, WIRES Executive Director Larry Gasteiger said it was important to get states supporting transmission.

"I completely recognize the importance of that engagement in order to have success in moving forward and getting state buy-in on some of these projects in order to move forward," Gasteiger said. "So I agree, I think the community where some of the success stories have been — look at things like the MISO [Multi-Value Project] process, which was a whole array of projects that came out of a process, and the underlying theory behind them — it was something for everyone in that process at the end of the day, and you had large buy in among all of the involved states, and that was absolutely critical." ■

Lauby Says U.S. 'On the Right Track' After Iberian Blackout

By Holden Mann

Why This Matters

Several of the steps that Spain's government and grid operator recommended in their reports on April's blackout already are being followed in the U.S., NERC Chief Engineer Mark Lauby told FERC commissioners.

NERC Chief Engineer Mark Lauby told FERC commissioners that two recent reports on the Iberian Peninsula outages of April suggest the U.S. is "on the right track" regarding necessary steps to protect the grid from similar incidents.

Speaking at FERC's monthly open meeting, Lauby reviewed the reports released June 17 by the *Spanish government* and June 18 by grid operator *Red Electrica* on the blackout that left the entire population of Spain and Portugal — as well as parts of France — without power for up to 18 hours. The reports concluded that traditional synchronous generation could not adequately control high voltage resulting from frequency oscillations on the grid. (See related story, *Expert Says Spain Blackout Unlikely in U.S.*)

"Initial thoughts were that this event was maybe driven by reduced inertia or frequency ride-through," Lauby said, referring to speculation in the days after the blackout that the high proportion of solar, wind and battery resources on the Spanish grid made it difficult for Red Electrica to manage the oscillations. "But it's become clear — from the Spanish reports, anyway — that the challenge was the ability to manage the grid's static and dynamic voltage."

Reviewing the sequence of events, Lauby said the frequency oscillations began around noon April 28, first with local oscillations between the Spanish and Portuguese systems and then an inter-area oscillation that "raced … all across the continent." Red Electrica activated its mitigation measures in response to the oscillations, after which voltage began to rise.

According to the government report, 11 thermal generation plants and an unspecified amount of hydraulic generation were available for voltage control at the time of the blackout. Spain's electricity regulations do not allow renewable energy resources and battery energy storage systems to be used for voltage control. Red Electrica attempted to combat the voltage fluctuations with static reactive devices, which reduced system voltage but left the operator with less flexibility because of the stepwise "all-or-nothing" nature of the devices.

At 12:32:57, about 10 minutes after the voltage began to rise, 355 MW of generation of unknown type left the grid after a collector substation tripped offline due to overvoltage. Within the next 20 seconds, an additional 1.5 GW including four wind farms and four solar installations was lost. After another two seconds, as the Iberian grid began to lose synchronization with the rest of the European system, the AC lines between France and Spain were disconnected, and the Spanish and Portuguese systems collapsed at 12:33:24, less than 30 seconds after the initial generation loss.

Reviewing the recommendations in the Red Electrica and government reports, Lauby noted that several of them are measures that U.S. grid operators already are required to follow.

Mark Lauby, NERC | *FERC*

"Some of the standards we have in place, for example our voltage and reactive standards, along with FERC Order 827, ensure sufficient dynamic reactive support is planned and operated," Lauby said. He noted that Red Electrica's recommendation of a review of overvoltage protection settings is similar to efforts already underway in the form of a Level 3 alert approved by NERC's Board of Trustees in May setting out essential actions regarding inverter-based resource performance and modeling. (See *NERC Warns Summer Shortfalls Possible in Multiple Regions*.)

Lauby also pointed out that unlike Spain's regulator, FERC and NERC already require that all generation units capable of voltage regulation, including IBRs, provide such service. In addition, the reports mention tools like synchronous condensers, static VAR compensators and static synchronous compensators that already are present in the U.S. grid.

Asked by FERC Commissioner David Rosner whether the reports suggested any "gaps in [NERC's] reliability standards" that could lead to similar incidents, Lauby said he didn't see any "glaring gaps" but emphasized the importance of continuing to work with experts and equipment manufacturers to identify vulnerabilities.

Lauby also told attendees that the European Network of Transmission System Operators for Electricity, an association of 40 transmission system operators spanning 36 European countries, is preparing its own analysis of the Iberian blackout, to be released in September. He said NERC "will wait for that report to gain any [further] insights" into the incident. ■

Northwest Summers Now Include 'Huge' Energy Flows from California

Flow Reversal Brings Unexpected Effects, PGE Tells Oregon Regulators

By Elaine Goodman

For decades, Portland General Electric watched electricity move from north to south through its system during the summer, as relatively cheap hydroelectric power from the Pacific Northwest flowed to California.

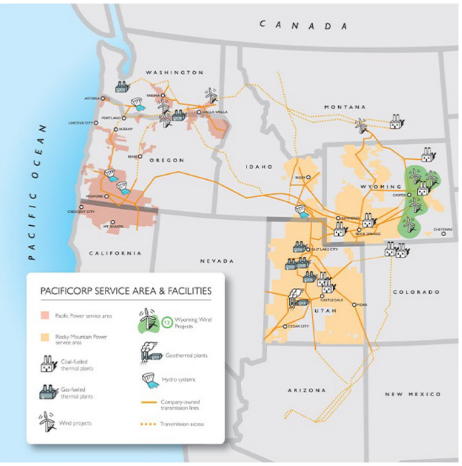
But now, the flow on a typical summer day has reversed, with electricity moving from south to north, PGE officials told the Oregon Public Utility Commission.

"With the 10,000 MW of batteries and 20,000 MW of solar that California has, we see a reversal of paths, where there is a huge northbound flow from California — cheap energy — up into the Northwest," said Lee Recchia, PGE's senior manager of the grid control center.

Recchia spoke during a special OPUC meeting on summer readiness on June 24.

The flow reversal has created issues that PGE "didn't really see coming," Recchia said, particularly on the North of Pearl transmission path. The Bonneville Power Administration owns the Pearl flowgate, and PGE partly owns some 230-kV lines out of Pearl.

"We've seen some overloads that we hadn't seen in the past years, and it's one of our big congestion points," Recchia said.



PacifiCorp's summer readiness has been boosted by the addition of 1,000 MW of wind resources, 320 MW of solar and a 75-MW natural gas plant expansion since summer 2024. | *PacifiCorp*

PGE has developed a North of Pearl action flow chart for operators and a forecasting tool. The utility also is in regular discussions with BPA.

"It strikes me as one of those places where there will be really important coordination, as they move forward with their Markets+ decision," OPUC Chair Letha Tawney said. "This could get hairy."

PacifiCorp Preparations

Weather forecasters predict higher-than-average temperatures for most of the West this summer.

But PacifiCorp's predicted summer peak of 11,163 MW is not a significant jump from its 2024 summer peak, according to Ben Faulkinberry, senior originator in the company's energy supply business unit.

Since summer 2024, PacifiCorp has added 1,000 MW of wind resources and 320 MW of solar while also completing a 75-MW natural gas plant expansion. Another 400 MW of wind and 500 MW of solar are expected by the end of this summer.

PacifiCorp also energized the Gateway South transmission line, a 500-kV line that will carry electricity from the company's wind power projects in Wyoming to the load center in Utah.

With the new line in service, curtailments of Wyoming wind are down by about 70%, Faulkinberry told the commission. And during the summer, when there's less wind in eastern Wyoming, Gateway South gives PacifiCorp greater capacity to transact with market participants on the east side of the Rockies, he said.

"Our load requirement has not jumped substantially. We've added new resources. We've added new connectivity," Faulkinberry said. "So we're feeling, on the whole, pretty well-situated going into summer 2025."

Still, PacifiCorp faces potential summer threats. One concern is the possibility of extreme heat simultaneously hitting the Pacific Northwest, Desert Southwest and California regions.

> **Why This Matters**
>
> The reversal of summer transmission flows on the West Coast shows how significantly California solar and battery resources are altering the dynamic of the region's grid.

"That really puts a stress on our system as well as for the region as a whole," he said.

Another worry is wildfire, which could impact transmission across the grid. Southern Oregon and southern Idaho, areas where PacifiCorp has "some pretty key connectivity," are particular concerns, Faulkinberry said.

PacifiCorp also is expanding its demand response programs, including Cool Keeper, which has been a longstanding program in Utah.

Through the program, which PacifiCorp is now rolling out in Oregon, a technician installs a device that curbs power to the air conditioner compressor of a residence or small business. The company controls the device, and the customer can't bypass it.

A typical Cool Keeper event lasts 5 to 15 minutes — enough time to stabilize the grid when it gets out of balance.

Because the fan and air handling components of the air conditioner keep running, customers generally don't feel uncomfortable. Customers receive a bill credit for participating.

PacifiCorp forecasts that participation in Cool Keeper, along with a battery incentive program called Wattsmart, will offset the need to build three natural gas peaker plants within four to five years. ■

New CAISO-Powerex Dispute Centers on 'Voluntary' Nature of EDAM

Powerex Claim 'at Odds with the Factual Record,' ISO Contends

By Robert Mullin

CAISO has dismissed Powerex's contention that the ISO only recently has "revealed" that participation in its Extended Day-Ahead Market is voluntary at the balancing authority level but not voluntary for "individual customers" operating within the BA participating in the market.

"Powerex's claim is incorrect and directly at odds with the factual record," CAISO wrote in a June 17 "*limited answer*" filed in the FERC docket for PacifiCorp's proposed revisions to its Open Access Transmission Tariff, intended to facilitate the utility's participation in EDAM (ER25-951).

In February, PacifiCorp's OATT proceeding had opened yet another front in the competition between EDAM and SPP's Markets+.

That's when Powerex — a strong Markets+ backer — published a paper arguing that PacifiCorp's revisions showed the EDAM contained a "design flaw" in how it allocates transmission congestion revenues in situations when congestion results from loop flow. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

Why This Matters

The dispute over the voluntary nature of EDAM represents yet another front in the ongoing competition between the CAISO market and SPP's Markets+.

CAISO and PacifiCorp initially rebuffed that characterization, but the ISO and its stakeholders did move to quickly address the matter with congestion revenue allocation rule changes developed through an expedited stakeholder process. (See *CAISO Approves New EDAM Congestion Revenue Allocation Design*.)

But the issue spelled out in CAISO's June 17 answer represents a new twist in the running dispute in the OATT proceeding.

In its answer, CAISO was responding to a June 11 comment Powerex submitted in the docket in which the Vancouver, B.C.-based power trader said the ISO has long promoted the EDAM as "voluntary and incremental" — a "natural evolution" of the Western Energy Imbalance Market (WEIM).

But, Powerex went on to contend, in a *May 19 filing*, CAISO for the first time "revealed" a "radically different approach" in which "EDAM could no longer be described as voluntary at all because only PacifiCorp (or other prospective balancing authorities) will be offered the choice to participate in EDAM."

Powerex was pointing specifically to CAISO's statements around an EDAM provision that allows a participating BA to "carve out" the embedded transmission of nonparticipating transmission service provider (TSP) from EDAM's market optimization. In the May 19 filing, the ISO said it agreed that PacifiCorp had the right to take that action but added that "any such carveouts should be an option of last

PacifiCorp's Gateway West transmission line. The utility's grid has been at the heart of a running dispute around how CAISO's EDAM will handle transmission rights. | *Quanta Infrastructure Solutions Group* resort."

Instead, CAISO argued, a "similar and more efficient" option would be for the nonparticipating TSP to self-schedule the use of its own transmission within EDAM and directly settle the associated energy schedules, including congestion price differences, with the market operator."

Powerex said this showed CAISO was seeking to "achieve this compulsory participation" and create a "captive market" along the lines of an RTO, but without providing the full benefits of an RTO.

That would mean PacifiCorp's decision to join the market would "in turn, require every electricity transaction and every delivery by every customer in PacifiCorp's area to take place through EDAM," Powerex wrote. "In addition, once PacifiCorp joins EDAM, all of its own transactions and all of its own deliveries will also be required to occur entirely through EDAM."

Powerex went on to warn that "if CAISO's new vision for EDAM is accepted, it would effectively make all activity in the electricity sectors of Wyoming and Utah, as well as significant portions of Idaho, Oregon and Washington, captive to CAISO's authority and ongoing decision-making under CAISO's governance structure, as a result of PacifiCorp's election to join EDAM."

'No Recognizable Reason'

In its June 17 answer, CAISO retorted that, although Powerex "professes surprise" at the ISO's statements in its May 19 filing, those comments represented "nothing new, surprising or radically different" from the ISO's previous description of EDAM.

"In fact, … CAISO was explicit in its 2023 tariff amendment filing to implement the EDAM design — on which Powerex submitted comments not even raising this subject — that participation in EDAM is voluntary at the balancing authority level but that all supply and demand in each EDAM balancing area must participate in the day-ahead market," the ISO wrote.

CAISO noted FERC approved this "foundational concept" of the EDAM in its December 2023 order approving the market's tariff and "should reject Powerex's factually inaccurate claims and its arguments based on those claims."

It pointed out that the transmittal letter accompanying the EDAM tariff filing stated the tariff included three options for the use of OATT transmission service rights in the market but that CAISO "had rejected proposals for other options involving broad or automatic opt-outs or carveouts of transmission capacity from the market."

The transmittal letter noted that CAISO and its stakeholders had determined that carveouts would create market inefficiencies, in part by potentially creating congestion in situations when a carveout leaves a path underused despite the availability of sufficient transmission capacity.

"In addition, Powerex contradicts history in claiming the CAISO is in 2025 announcing a 'radically different approach' under which every electricity transaction and every delivery by every customer in PacifiCorp's area will take place through EDAM. The CAISO made this requirement clear multiple times in its 2023 filing of tariff amendments to implement EDAM," the ISO wrote.

"In short, there is no cognizable reason for surprise on Powerex's part," it said. ■

CAISO Opens Bidding Process for $900M in Transmission Projects

Two Projects to Add More Than 105 Miles of Lines

By David Krause

CAISO is soliciting bids for two transmission projects in the San Francisco Bay Area to prepare the state for more data center load anticipated in the coming decade.

The projects are part of CAISO's approved 2024/25 transmission plan, which includes 31 projects. Two of these projects are eligible for a competitive solicitation process — the 230-kV San Jose B-Northern Receiving Station (NRS) line and the 500-kV Metcalf-Manning line — CAISO said at a June 25 transmission planning workshop.

The Metcalf substation, located in the South Bay Area, is one of the primary supply sources of energy for the San Francisco Bay Area. Load in the area is projected to increase 2.5 GW between 2026 and 2039 — or about 40% of the total load growth over those years. Most of the load growth will be from data centers, CAISO said.

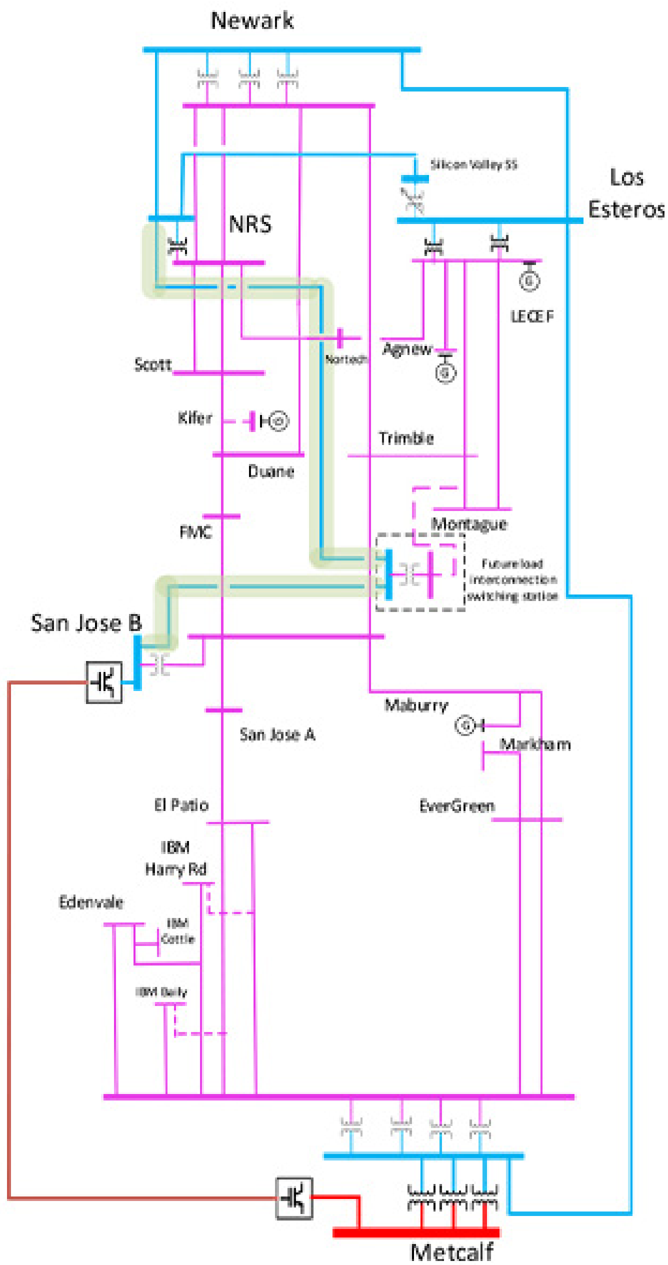
The Metcalf project includes about 100 miles of new 500-kV AC transmission line between the 500-kV Manning and Metcalf substations. The expected cost of the project is $500 million to $700 million, with a required completion date of June 1, 2034. The project is critical for maintaining reliability in a "major portion of the ISO-controlled grid," CAISO said in the meeting.

In the 2024/25 transmission plan, CAISO completed a study of constraints that might have a large impact on the bulk system or the heavily congested areas. The study found that minor congestion was observed on the recommended 500-kV Manning-Metcalf line, which indicates the high use of the 500-kV upgrade, CAISO said.

The second project — the San Jose B project — is a new, 7-mile transmission line expected to cost $150 million to $200 million, with a planned in-service date of June 1, 2030.

In less than three years, the load forecast in the San Jose area increased from 2,100 MW in the 2021/22 transmission plan to between 3,400 and 4,200 MW in the 2024/25 transmission plan. The San Jose B project will provide the extra energy. The project also will support two previously approved transmission projects in the area, which have designs that no longer are sufficient because of the increased load forecast. In the future, the San Jose B project will connect to a 115-kV load interconnection switching station owned by Pacific Gas and Electric.

For this cycle's bid process, CAISO revised certain parts of its application, including changes to its cost and cost-containment workbook and its project sponsor requirements. If only a single project sponsor is qualified for a project, that sponsor is automatically selected, CAISO said. ■



A schematic showing the San Jose B-NRS 230-kV line | *CAISO*

Oregon Lawmakers Pass Bill to Limit Utility Rate Increases

HB 3179 Seeks to Address the State's Spiking Energy Costs

By Henrik Nilsson

Oregon lawmakers have passed a bill that aims to mitigate the impact of rising energy costs on consumers by prohibiting residential rate increases during the winter and requiring energy companies and regulators to analyze consumer affordability when setting rates.

The state Senate voted 20-9 to approve *House Bill 3179*, also known as the FAIR Energy Act, on June 24, following its passage in the House on a 35-8 vote. The bill now advances to the desk of Gov. Tina Kotek for signature.

"Oregonians are struggling with unpredictable, poorly explained utility rate hikes that strain family budgets," Sen. Janeen Sollman (D) said in a statement after the vote. "House Bill 3179, the FAIR Energy Act, fixes this by requiring real-world impact assessments before rate increases, banning winter hikes, and ensuring clearer billing — delivering the affordability, fairness and transparency our constituents need."

"I have heard repeatedly from my constituents how frustrated they are with the dramatic and repeated increases in their utility bills," Rep. Nathan Sosa (D) said. "This bill will prevent the historic price shocks we have seen in recent years."

The FAIR Energy Act directs the Oregon Public Utility Commission to consider the economic impact of a proposed residential rate hike on consumers. It allows the commission to adjust rates to mitigate an increase "if the increase would affect the ability of customers to maintain adequate utility services."

The bill requires electric or natural gas companies to file an analysis of economic impacts on the company's residential ratepayers "if the company's return on equity is subject to review and modification."

The bill also will impose a freeze on residential rate increases from Nov. 1 to March 31 and would require companies to establish a multiyear rate plan that is no less than three and no more than seven years long. The bill prohibits increases within 18 months of a previous hike until Jan. 2, 2027, or when the PUC adopts new rules on multiyear rate plans.

Utilities also must share a visual breakdown to inform customers what they are paying for.

Subject to PUC approval, the bill allows a public utility to issue bonds and securitize debt to cover costs associated with capital investments or other expenses.

"We've seen a huge response from customers who are fed up with constant energy bill increases," Jennifer Hill-Hart, policy and program director at the Oregon Citizens' Utility Board, said in an email to *RTO Insider*.

"Last year, nearly 5,000 Oregonians wrote to the Public Utility Commission about rate hikes. Before 2024, we would see maybe 200 public comments a year," Hill-Hart said. "We are pleased to see lawmakers listening to the needs of communities."

Since its introduction in January, the bill has undergone several amendments, including updating the timeline for when utilities can increase rates and clarifying what data should be included in the rate analysis of the economic impact on consumers.

In the first version of the bill, the PUC would have determined whether the proposed rate is fair by first assessing if it would result in an increase of the public utility's revenue by 2.5% or more. That requirement was removed from the final bill.

'Major Change' to Ratemaking

"There is optimism HB 3179 can not only help smooth customer rates but also offer utilities a constructive/improved ratemaking process," investment bank Jefferies noted in a June 23 newsletter.

Simon Gutierrez, a spokesperson for PacifiCorp, told *RTO Insider* ahead of the bill's passage that Western utilities and the industry face "broad affordability challenges" because of inflation and wildfire risk.

> **Why This Matters**
>
> The proposed legislation would overhaul Oregon's ratemaking process and freeze any increases during the winter months.

"We understand price increases can be a burden to Oregon families, and we remain steadfast in our commitment to customers and communities and will continue seeking new ways to reduce impacts to customer bills," Gutierrez said. "With HB 3179 now in the final stages of consideration by Oregon lawmakers, Pacific Power commends the legislative and stakeholder efforts to help mitigate the potential impacts included in this bill."

"If it becomes law, HB 3179B will mark a major change to regulated utility ratemaking in Oregon and will provide the OPUC with new tools to manage utility bill affordability for our customers," Portland General Electric spokesperson John Farmer said before the June 24 vote. "We look forward to working with stakeholders and the OPUC to implement this bill."

Garrett Martin, policy adviser at the Oregon PUC, said in addition to freezing rate increases during the winter months, "HB 3179 also includes provisions that will allow the commission to proactively schedule rate cases and multiyear rate plans rather than only react to utility filings covering a single future year."

"This shift will allow the OPUC to create more predictable rate changes and manage regulatory workloads so investigations can rigorously focus on affordability," Martin said. "HB 3179, if enacted, will also aid the OPUC in considering additional factors when determining utility rates and provide additional clarity for the commission and utility customers about how utilities spend customer dollars." ■

Oregon PUC Approves IOUs' Wildfire Plans, Issues Recommendations

By Henrik Nilsson

The Oregon Public Utility Commission has approved wildfire mitigation plans proposed by the state's three investor-owned utilities and supported staff recommendations that the commission said the utilities should implement in the future.

The three commissioners unanimously signed off on wildfire *mitigation plans* for Portland General Electric, Pacific Power and Idaho Power.

PUC Chair Letha Tawney noted that when discussing wildfire in the utility space, there usually are two intertwined questions: Are the utilities meeting the requirements of the law, and are the utilities finding the most cost-efficient way to reduce wildfire risk?

"Today, we're not talking about the cost," Tawney said at the PUC's June 26 meeting. "Today, we're talking about whether the utilities are appropriately evaluating the risk [and] responding to that evaluation and what that evaluation tells them."

"I still expect the utilities to provide staff with all the evidence that these spending choices are prudent and reasonable," Tawney added.

The PUC enlisted Climate Wildfire and Energy Strategies (CWE) to independently evaluate the IOUs' wildfire mitigation plans. PUC staff also performed their own assessments of the plans. The PUC and CWE largely reached the same conclusions on whether the utilities had followed through on last year's recommendations. However, there were some differences.

For example, even though the PUC found that Pacific Power, a division of PacifiCorp, had "partially met" recommendations related to ignition risk driver investigations, short-term fuels and assessment of vegetation actions and timing, CWE

Shutterstock

concluded the utility "did not meet" the recommendations.

Heidi Caswell, division administrator of safety, reliability and security at the PUC, said CWE's analysis was "constrained" to a limited time frame and the specific docket of each utility, while "staff's view could be informed by other dockets."

As for PGE and Idaho Power, CWE and the PUC agreed the two utilities either had met or partly met staff recommendations.

"Our wildfire mitigation plan, which is approved by the Oregon Public Utility Commission, reflects the company's ongoing efforts and substantial investments to protect the communities we serve from the risk of wildfire," Simon Gutierrez, a spokesperson for PacifiCorp, told RTO Insider in an email. "The company is committed to working closely with policymakers and regulators to prevent wildfires before they happen."

Recommendations

The PUC provided three recommendations to Pacific Power:

Outline how it plans to incorporate future land use and climate changes to demonstrate how Pacific Power's "long-term plans align with the future state for those areas." The PUC noted California has similar requirements, saying some of the processes Pacific Power uses in California can be shared in Oregon.

- Provide wildfire risk scores for circuit segments.
- Justify use of vendor project management to reduce costs to deliver covered conductor projects.
- PGE received one recommendation:
- Explain actions to address outage data quality, including why PGE uses a record set of only six years and provides information only on vegetation and equipment failure.

Kellie Cloud, PGE senior director of wildfire and operational compliance, told *RTO Insider* the utility is "pleased" with the approval and the "acknowledgment of the progress in our wildfire mitigation planning process."

"We look forward to working with commission staff, stakeholders and other utilities to continue to advance our mitigation plans," Cloud said. "PGE has been executing mitigations in advance of fire season; we are now actively monitoring and managing risks in the active season."

Idaho Power received three recommendations:

Provide a timeline for when it will model wildfire risk for circuit segments and wildfire risk zones.

Clarify its analysis of its battery program and whether it aims to pursue a rebate program for medically vulnerable customers in Oregon. If not, the utility should explain how those customers are supported during public safety power shutoffs and other events.

Share its vegetation risk index with other IOUs.

Jordan Rodriguez, spokesperson for Idaho Power, told RTO Insider the utility appreciates the PUC's approval of the plan. Rodriguez added that the wildfire plan details how the utility uses "wildfire risk modeling tools, extensive system hardening efforts and growth in coordination with community partners."

Future Plans

The utilities presented their plans in February and touted various grid-hardening efforts under way, such as undergrounding of lines, installment of more powerful weather stations, fire-proofing utility poles and improved forecasting models. (See *Oregon Utilities Enter 2025 With Ambitious Wildfire Plans*.)

During the meeting June 26, CWE consultant Melissa Semcer said communities on the West Coast are facing the threat of "catastrophic wildfires," whether from ignition by utility equipment or another source. Semcer argued the future of wildfire prevention should not just focus on undergrounding or other traditional mitigation efforts.

She posed the question of whether ratepayer dollars can be used for land management outside of utilities' right of way "or to potentially invest into home hardening."

"And might that actually be less expensive and negate the need to have some of those larger investments of undergrounding?" Semcer said. "And I think that's really the bleeding edge of where this conversation is across the West at this point, is to maybe move out of our boxes and our silos that we've all … been in and try to come up with what is the comprehensive solution, because it is such a large amount of money." ■

Local Congestion Causing Most California Curtailments, CAISO Says

Additional Battery Storage Could Help Ease the Problem

By David Krause

Local line congestion is the primary cause of renewable curtailment in California — and the amount is increasing each year, CAISO said during its second-quarter Market Performance and Planning Forum on June 26.

About 80% of curtailment is due to local line congestion in CAISO's region, rather than oversupply, which is sometimes thought of as the reason why renewable generation is reduced — or curtailed.

"The extent of congestion is widespread, going from major and regional conditions to more local conditions," CAISO staff said at the forum.

The two primary types of curtailment for solar and wind resources are "Economic - Local," which is the market dispatch of generators with economic bids to mitigate local congestion, and "Economic - System," which is the market dispatch of generators with economic bids to mitigate systemwide oversupply.

On May 14, about 27,000 MW of wind and solar was curtailed for "Economic - Local" reasons and about 4,000 MW for "Economic - System" reasons, CAISO staff said. Overall, about 94% of renewable curtailment is for solar resources, and this practice is not unique to specific locations in CAISO's region, staff said.

In recent years, solar oversupply has been reduced because more solar farms have been built with battery storage facilities nearby — a development approach that allows batteries to more easily charge during hours when solar production is plentiful, CAISO staff said. In general, battery storage resources are helping to flatten the net load in the region, meaning fewer conventional generation resources, such as gas or hydropower, need to be used to meet demand, staff added.

During the forum, ISO staff noted the region's load has been fully met with renewable resources during intervals on 40 days so far in 2025. Renewables serve load mostly during midday hours when batteries are charging, solar production is high and demand is low.

At the forum, CAISO also reviewed battery performance on March 4 and 5. On March 5, the battery fleet was significantly less charged than normal: 13,800 MWh compared to 35,000 MWh on March 4, requiring gas generation and imports to increase significantly to make up for the lack of battery storage energy available to meet demand, staff said. Battery storage energy was low on March 4 due to higher energy prices during the middle of the day, which minimized how much solar power the batteries soaked up, staff said.

CAISO staff also noted that, during winter months, California's morning peak is becoming as high as the evening peak. The ISO is studying how the grid can rely on storage resources to meet both morning and evening peaks, staff said.

CAISO said certain solar generation forecasting errors increased in 2025 compared with previous years, in part due to growth in solar capacity.

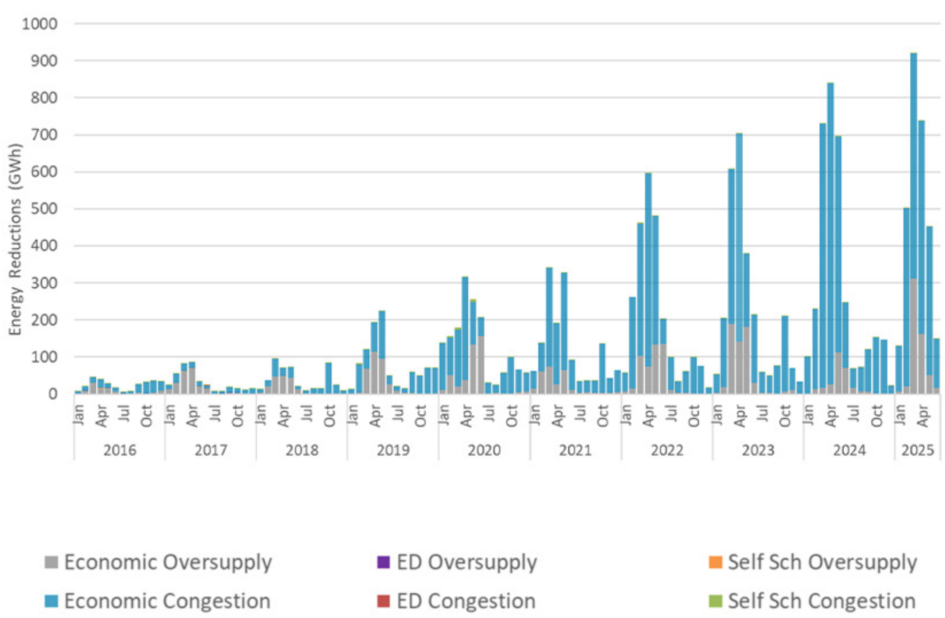
CAISO staff also reviewed the results of a recent change to how battery resources are managed on the grid. The results specifically looked at how batteries performed now that the ISO is accounting for a battery's state of charge in the upward flexible ramping product program.

Due to this change, the grid operator observed that fewer flexible ramping up (FRU) awards went to storage resources during morning and evening peak times. However, the average resource usage under FRU procurement did not change significantly, said Kun Zhao, CAISO engineer.

"This effort will be a longer-term monitoring project for us, and we'll definitely give updates," Zhao said. ■

Why This Matters

The reasons for solar curtailment in California are shifting and now becoming more clear, potentially allowing for CAISO to come up with better solutions.



Energy reductions on CAISO's system by cause | *CAISO*

Vegas: ERCOT Grid 'Strong' Heading into Summer

By Tom Kleckner

Much like a president addressing Congress, ERCOT CEO Pablo Vegas stood before his Board of Directors and declared the state of the ERCOT grid to be "strong."

"The grid is seeing improvements from a reliability perspective, season over season, and that's important as we get into the start of the summer season to understand really what is the state of the grid," Vegas told his directors June 24. "The state of the grid is strong. It is reliable. It is as reliable as it has ever been, and it is as ready for the challenges of extreme weather that we have ever experienced. I feel confident that we are ready for this upcoming summer season."

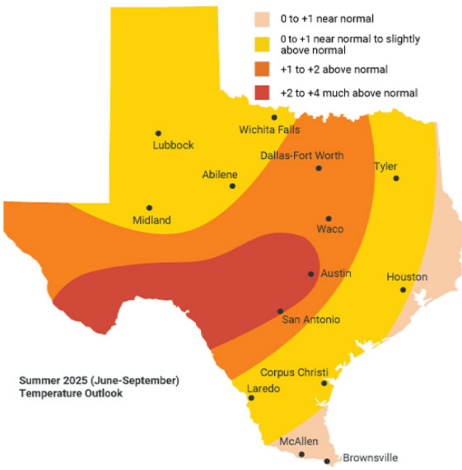
Good thing too, as ERCOT is forecasting demand to peak at 87.5 GW this summer in what staff are expecting to be above-normal temperatures. That would replace the current high of 85.5 GW, set in 2023.

The Texas grid operator's load peaked at 73.7 GW in 2021. It has added 4,600 MW of large loads since then, with an additional 1,848 MW energized but not yet operational.

"We're seeing significant and unpredictable load growth," Vegas said, referencing data centers, industrial electrification, manufacturing reshoring and population expansion. "The characteristics and the pace of this new load in ERCOT is unlike anything we have seen or managed historically."

Fortunately, Texas is the nation's leader in wind and solar capacity, Vegas said, and it is experiencing "unprecedented growth" in battery storage and distributed energy resources. ERCOT has energized 9,216 MW of solar and battery storage capacity since last summer, accounting for all but 429 MW of new capacity since then.

Solar and batteries have played a key role in meeting ERCOT's peak risk hour, which usually comes around 9 p.m. during the summer evenings. As Vegas said, solar energy is "very well suited" to support the air conditioning load during the heat of the afternoon, and batteries are "very well positioned" to help during the evening ramps.



Texas and ERCOT are expected to weather above-normal temperatures this summer. | *ERCOT*

Solar and batteries "are extremely helpful during the summer seasons," he told directors. "The risk of emergency events during those periods of time is shrinking, dropping from over 10% a year ago to under 1% this year."

At the same time, the grid operator has seen a net loss of 366 MW of gas generation. Much of that comes from the retirement of two gas units at San Antonio's Braunig power plant, but Vegas said derates and indefinite mothballing at other gas resources have also contributed to the reduction.

"Even though we've seen significant additions and other types of resources to be able to meet the needs of the system in a balanced way going forward across all periods of time and across all weather extremes, we are going to need to see balanced growth in supply," he said. "That remains a concern and an issue to keep a focus on as we move forward."

The immediate focus, of course, is meeting demand this summer. The effort to mitigate the transmission constraint south of San Antonio has picked up steam. The first five of 15 mobile generators necessary to relieve the constraint have arrived in San Antonio from Houston and are expected to be operational by July 4. All 15 mobile units are expected to be interconnected to CPS Energy substations and able to provide 450 MW of capacity by mid-August.

The mobile units will offer an emergency backup service to help protect the constraint while transmission upgrades are being made, Vegas said.

The units were originally leased from LifeCycle Power by CenterPoint Energy in Houston. The utility is allowing the units to be dispatched by ERCOT, without compensation, through March 2027. (See *ERCOT: Agreement Reached to Use Mobile Generators*.)

Staff have been working on the agreement since February, when they were unable to extend reliability-must-run agreements to two of the three aging Braunig gas units slated for retirement. ERCOT earlier entered into an RMR contract with CPS for Braunig Unit 3, its first since 2016.

Vegas said CPS found "fairly significant upgrades and maintenance activities" needed to ensure the unit, which dates back to 1970, can continue to operate reliably. ERCOT expects to pay CPS $49 million this year under the RMR contract and an additional $10 million in 2026. Together, that's a $12 million increase from when the RMR contract was executed.

"We believe that the new costs are well justified within the cost matrix, supporting the cost benefit of keeping this unit running for the foreseeable next couple of years until the transmission solution is developed, completed and ready to allow this unit to retire," Vegas said.

He said staff intend to propose a protocol change to allow a timelier recovery of the costs. ERCOT's current RMR settlement processes do not allow those costs to be reimbursed when they are incurred.

Chris Coleman, the grid operator's meteorologist, told the board he expects above-normal temperatures and below-normal precipitation for most of Texas. The past three summers have ranked among the state's six hottest since 1895.

"The lean is for summer 2025 to be hotter than 2024," Coleman said. ■

ERCOT Board of Directors Briefs

ERCOT 4.0 Shapes Path Forward for the Grid Operator

ERCOT CEO Pablo Vegas has gone public with the grid operator's internal terminology that is shaping the market's path forward, defining it for his Board of Directors and stakeholders.

"This represents more than just the branding of current activities that we have underway," Vegas told the board during its June 23-24 meeting. "It really represents a distinct new phase in the ERCOT market. It also provides a strategic lens to look at the priorities and the initiatives that we're going to be investing in to make sure that we continue to deliver on our mission, which is getting more complex and more dynamic every year."

Labeled "ERCOT 4.0," the construct builds on previous versions of the grid operator's market and its transitions: 1.0 (original formation in the 1970s), 2.0 (deregulated competitive markets and the zonal market in 1999) and 3.0 (the nodal market in 2010).

"Each of these transitions was driven by a combination of either technology changes, regulatory changes [or] market-driven forces. ERCOT 4.0 reflects this transformation that's underway right now," Vegas said.

He said ERCOT 4.0 is defined by the exponential growth in system complexity and the convergence of three major drivers: the rapidly changing resource mix, significant and unpredictable load growth, and technology-driven operational changes, such as artificial intelligence advances and high-frequency data access.

"This is changing how we forecast. This is changing how we operate. This is changing how we plan," Vegas said. "The convergence of these three things … are the core underpinnings of what ERCOT 4.0 looks like for the next generation of ERCOT. This is a new paradigm."

Vegas said the grid operator will have to evolve its planning assumptions "to account for the uncertainty and the variability that we're seeing across both supply and demand." He said grid operations will have to become more adaptive and market mechanisms will have to be re-evaluated to ensure "those signals support long-term system reliability as well as short-term market efficiencies."

ERCOT CEO Pablo Vegas says the grid operator's Version 4.0 provides a strategic lens into the future. | *© RTO Insider*

"Probably most critically of all, our workforce is going to have to be equipped to lead in a system that is increasingly software-defined, data-rich and constantly changing," Vegas said, noting the grid operator is investing in professional development and other tools so the team can "operate and lead in this new reality."

Staff are focused on innovation to transform the organization and maintain operational excellence in a more complex system.

"It's a huge opportunity to reinforce our leadership in the energy economy here in Texas," Vegas said.

He closed his comments by tying ERCOT's *2025 Innovation Summit* in May to ERCOT 4.0. The summit drew more than 450 attendees, with more than 400 other people livestreaming the event.

"It was an opportunity to really showcase innovation efforts, not only within ERCOT, but [also] what's happening in transformations around the world and around the United States, bringing people together to talk about the most complex issues that we're dealing with, learning from each other, establishing networks of communication that are going to be helpful as we continue to work on solving these problems together."

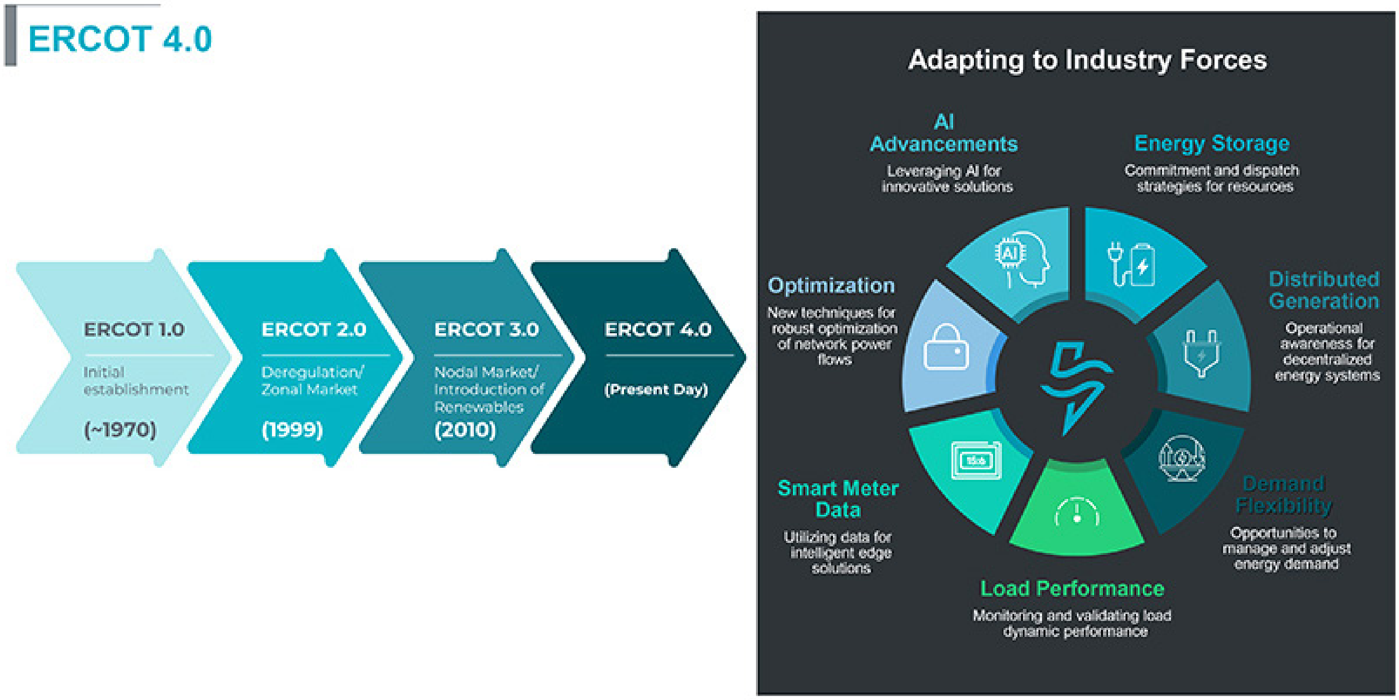
Board Approves $1.07B 2-year Budget

The board approved a two-year budget of $485 million for 2026 and $585 million for 2027, totaling $1.07 billion. However, the budget includes a system administrative fee of 61 cents/MWh, down 2 cents from the current fee.

Both changes go into effect in January 2026.

Board Chair Bill Flores, who also chairs the Finance and Audit Committee, acknowledged that the biennial budgets are "substantial increases from where we are today."

"But as we all recognize," he said, "because of the mandates promulgated by the Legislature in the last two legislative sessions, as well as the increasing complexity and the dynamic nature of this market, as well as the focus on reliability, the cost of running the organization is higher than it was before."



ERCOT's transition from 1.0 to 4.0 | *ERCOT*

He said the budget includes "appropriate" funds and staff to address ERCOT's strategic objectives and comply with the financial corporate standard and associated financial performance measures. The budget also funds the Independent Market Monitor and compliance with Texas Public Utility Regulatory Act and NERC obligations.

Flores said the budget assumes the administration fee can be kept flat for up to six years.

RTC+B Market Trials Begin

Market trials for the *Real-time Co-optimization+ Batteries* (RTC+B) project are underway and proceeding well, staff told the board.

Matt Mereness, senior director of market operations and implementation, said ERCOT has received the final deliveries of vendor code and completed two operating day end-to-end tests of systems and integration. He said the test environment was deployed weeks ahead of its May 5 start date, and a first round of defects was fixed and redeployed later in the month.

After establishing connectivity with market participants and testing submissions, the RTC+B project will begin parallel production trials July 7. Mereness said market trials will focus on frequency control tests in the September-October time frame.

"All the participants will put in reasonable offers that represent [a percentage] of their costs, and we'll start [dispatching]. That'll be the real-time co-optimization," Mereness said. "They'll have [ancillary service] offers in, and ERCOT will start to print prices and signal where [participants] should go, but no one will go there. Here's the solution, but don't follow it."

The project is set to go live Dec. 5.

Staff Responds to IMM Report

ERCOT staff responded to the IMM's recent *State of the Market report* for 2024, saying, "Overall, it's a very good and well-written report."

"There are definitely some things we agree with and some other things that we may be in disagreement," said Keith Collins, vice president of commercial operations.

He said staff are aligned with the IMM's comments on improvements to ERCOT contingency reserve service (ECRS), which reduced the product's average price from $76.77/MWh to $9.62/MWh, and the effective load-carrying capability in the grid operator's Capacity, Demand and Reserve report.

"There are a few recommendations or items that the IMM pointed out that we believe we've already addressed," Collins said.

Responding to the IMM's recommendation that ECRS include a forecast trigger, he said ERCOT has a three-part trigger for the product. Collins said a trigger that looks forward at the net load ramp addresses that need.

In its report, the IMM continued to recommend that the grid operator reconsider its policies for procuring and deploying ECRS. (See *ERCOT ESRs, Solar Production Lessen AS Costs*.)

ERCOT also disagreed with the Monitor over non-spinning reserves' duration. The grid operator wants four hours, while the IMM favors a one-hour duration.

2 Tx Projects Approved

The board approved a pair of Oncor transmission projects in West Texas with combined total costs of $974 million.

The $855 million Delaware Basin Stage 5 *project* addresses reliability concerns and accommodates "significant and rapid load growth" in the petroleum-rich area. Oncor will build 220 miles of transmission lines in creating an import path to serve load now that the basin's peak demand is greater than a 5,422-MW threshold. (See "Oncor $855M Project Endorsed," *ERCOT's TAC Extends Duration of Ancillary Services*.)

The $119 million, 138-kV Tredway Switch

and 138-kV Expanse-to-Tredway project entails upgrading 29 miles of lines and updating other facilities and infrastructure to address reliability issues. Oncor expects to finish the project in December. (See "TAC Endorses $119M Oncor Project," *ERCOT's TAC Endorses Congestion Management Plan*.)

Both projects were selected by ERCOT's Regional Planning Group from other alternatives. As Tier 1 projects with costs exceeding $100 million, they require board approval.

With little discussion, the board also approved:

- the third phase of the *Aggregate Distributed Energy Resource* (ADER) pilot project, which enables a new participation model for resources providing ancillary services but that are not in the five-minute real-time energy market. The first two phases limited total registered capacity of all ADERs to 80 MW for energy and 40 MW for non-spin and ECRS; staff proposed increasing the limits to 160 MW and 80 MW, respectively, for Phase 3. (See "TAC Endorses ADER Doc," *ERCOT's TAC Extends Duration of Ancillary Services*.)
- revisions to ERCOT's methodology used to calculate the *maximum daily resource planned outage capacity*. The modifications are intended to provide sufficient outage capacity compared to historical levels by applying a risk-based construct for outages more than seven days ahead. (See "Outage Capacity Changes," *ERCOT's TAC Extends Duration of Ancillary Services*.)
- a *real-time market correction* of $81,858 to market participants after a routine software update changed an energy management system setting to its default value, causing a stricter limit on a generic transmission constraint (GTC). That led to the activation of a post-contingency overload on the GTC, affecting dispatch optimization that resulted in a maximum shadow price of $5,251/MWh over March 28-29. The first operating day was corrected within a two-day business deadline, but not the second day. The maximum absolute value impact to counter-parties was $99,580.

Board Loses 2 More Directors

Chair Flores opened the meeting by

Board Chair Bill Flores | *ERCOT*

announcing that the two most recent independent directors, Alex Hernandez and Sig Cornelius, have resigned to pursue "new opportunities" in the ERCOT market. State law requires the 12-person board's eight independent directors to not have fiduciary duty or assets in the grid operator's territory.

Hernandez and Cornelius were appointed to the board in January. (See *ERCOT Fills out Board with 2 New Directors*.)

That leaves the board with three vacancies. Bob Flexon resigned in December 2024.

Flores said the board's selection committee is working to fill the three vacant seats. He said the goal is to have them in place by the board's September meeting.

Protocol Changes

The board approved a nodal protocol revision request (*NPRR1282*) and its associated Nodal Operating Guide revision request (*NOGRR277*) that provides longer-duration ancillary services and state-of-charge (SOC) parameters in advance of the RTC+B project's deployment in December.

The NPRR updates duration requirements to 30 minutes for regulation service and responsive reserve service and one hour for ECRS. It also revises reliability unit commitment studies' requirement to one hour for all ancillary services, excluding fast frequency response. (See *ERCOT's TAC Extends Duration of Ancillary Services*.)

ERCOT supported the measure, saying there is a need for a four-hour ancillary service to cover periods when deploying non-spin. Dan Woodfin, vice president of system operations, said staff analysis revealed that when non-spin is deployed, "we're basically having to cover the gap because of either an extended forecast error or units that trip offline."

"We can deploy reserves, but then we need to last longer until we can get the next generation committed to cover the gap or until the net load goes down," he said.

ERCOT is also developing dispatchable reliability reserve service as a four-hour AS product to cover risks.

Jupiter Power's Caitlin Smith, who chairs the Technical Advisory Committee, said the change conflates "duration" with SOC, "a misapplication of fundamental [energy storage resource] concepts [that] results in a drastic departure from current ERCOT standards regarding duration and state of charge."

The board agreed with ERCOT's commitment to revisit the NPRR once RTC+B becomes part of the market.

The directors also endorsed *NPRR1229*, which creates a process to compensate market participants when a constrained management plan or ERCOT-directed switching instruction trips a generator that otherwise would have remained online. (See *ERCOT's TAC Endorses Congestion Management Plan*.)

The consent agenda of unopposed protocol changes at TAC included five additional NPRRs, two NOGRRs, an Other Binding Document (OBDRR), an addition to the Planning Guide (PGRR) and a system change request (SCR) that:

- *NPRR1226*: directs ERCOT to prepare and publish estimated demand response data showing aggregated state-estimated load points selected by the grid operator. Loads selected for the report will be based on periodically updated offline analysis of the frequency and magnitude of reductions observed in historical state estimator load data that are associated with LMPs, ERCOT-wide conservation appeals or other market signals.
- *NPRR1238* and *NOGRR265*: introduces a new early curtailment load (ECL) category and establishes a process allowing loads to operate as an ECL so they can be accounted for differently in load-shed tables.

- *NPRR1267*: requires 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.
- *NPRR1271*: allows Mexico's state-owned electric utility, the Federal Electricity Commission (CFE), to opt out of a requirement to designate a user security administrator and receive digital certificates. CFE is registered with ERCOT as a transmission and/or distribution service provider, a load-serving entity and a resource entity.
- *NPRR1276*: incorporates an OBD, "*Emergency Response Service Procurement Methodology*," into the protocols to standardize the approval process.
- *NOGRR275*: aligns the guide with protocol changes to eliminate scheduling center requirements for qualified scheduling entities that are not wide-area network participants.
- *OBDRR054*: creates 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*: adds 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.
- *SCR830*: implements a machine-to-machine client credentials authentication flow using OAuth 2.0, allowing for certain read-only endpoints of the GINR Rest Application Programming Interface to be exposed for authorized use. ■

— Tom Kleckner

First Texas Energy Fund Loan Goes to Kerrville Utility

By Tom Kleckner

The Texas Public Utility Commission has executed the first loan agreement under the state's low-interest energy fund to the Kerrville Public Utility Board, the developer of a 122-MW natural gas plant.

The loan agreement was finalized June 25 under the *Texas Energy Fund's* In-ERCOT Generation Loan Program. The program has been allotted $5 billion by state lawmakers to help provide up to 10 GW of new gas-fired generation for ERCOT.

The PUC and Kerrville PUB agreed to a 20-year loan of up to $105 million for the Rock Island Generation Project at a 3% interest rate, subject to customary financial closing procedures. The project's total costs are not to exceed $175 million, and the project must meet *minimum performance standards*, as outlined in the program's rules.

The PUB *says* it will finance the remainder of the project through tax-exempt revenue bonds.

Rock Island will interconnect to the South Texas Electric Cooperative's grid in ERCOT's South load zone. Construction is scheduled to begin in the fall of 2025, and the plant is projected to begin operations by June 2027.

PUC Executive Director Connie Corona (left) and Kerrville CEO Mike Wittler sign the first Texas Energy Fund loan agreement. | *Kerrville PUB*

The site is almost 200 miles away from Kerrville, which is northwest of San Antonio. However, it has access to four natural gas pipelines, which was not the case in Kerrville.

Texas Gov. Greg Abbott (R) said in a *statement* that the plant, 75 miles away from the huge Houston load center, will "help bear the load of the largest electricity demand area in the state."

The PUC is tracking 18 other applications in the In-ERCOT program's due-diligence review, representing an additional 9.1 GW of gas generation. ■

IESO Moving Forward with Competitive Tx Plans

Most Projects Still Will Go to Incumbents

By Rich Heidorn Jr.

IESO will begin opening some transmission projects to competition under a hybrid rate model, with cost-of-service rates following an initial 10-year contract.

IESO, which has about 932 miles of new transmission lines planned or under development, says competition will lower costs and produce innovation.

The first projects eligible for competition may be identified as soon as the fourth quarter of 2025 when recommendations from the South and Central Bulk Study are due. The grid operator also has two other major transmission projects underway, with recommendations from the North of Sudbury Bulk Study and Eastern Ontario Bulk Study expected in 2026.

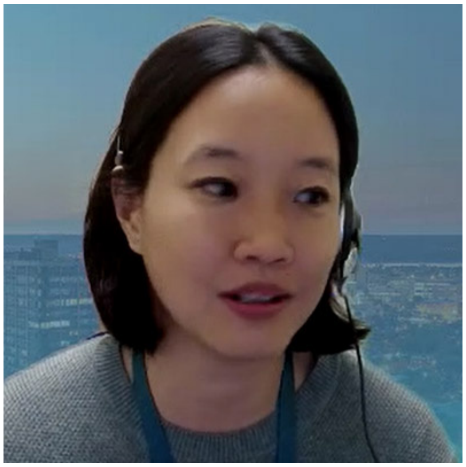
Once projects suitable for competition are identified by IESO, the province will issue a directive to formally launch competitive procurements.

Incumbent Projects

But only some projects will be open for competition.

"Not every project will be suitable for transmission procurement," Denise Zhong, IESO senior manager for resource adequacy and sector evolution, told more than 70 attendees at a June 25 *webinar* outlining the ISO's Transmitter Selection Framework Registry (TSF-R). "In fact, the majority of the projects that will be recommended through transmission planning will likely go to an incumbent transmitter. But we're looking at a very small subset of projects that will meet certain eligibility considerations."

The registry will allow prospective transmission builders to prequalify for upcoming procurements. Prequalifying bidders will cut procurement timelines by more than six months compared to issuing separate Requests for Qualifications for each procurement, IESO said. The Ministry of Energy and Mines' *Integrated Energy Plan* directed IESO to launch the registry by Aug. 15.


IESO's Denise Zhong | *IESO*

The plan listed three major projects that have been assigned to incumbent Hydro One.

To expand the province's north-south infrastructure, IESO is backing a 500-kV Barrie-to-Sudbury single-circuit line due in service in 2032 and has recommended beginning early development work on a second 500-kV line along the same route.

"IESO has determined that these projects are not suitable for a competitive procurement process given their urgent need," the Ministry said. Thus, the government will direct the Ontario Energy Board to designate Hydro One to develop the first line and to begin development work on the second.

Another project to strengthen the north-south "backbone," reconductoring the 230-kV Orangeville-to-Barrie line, also will be awarded to Hydro One, because it owns the line.

IESO also has rejected competition for a new double-circuit 500-kV line from Bowmanville Switching Station to an existing 500-kV station in the Greater Toronto Area, again selecting Hydro One.

Rate Model

IESO said it has decided to use a "partial contracting" model in which the winning bidder will receive a contract covering all costs of financing, designing, building, operating and maintaining the line for the first 10 years of its commercial operation. In year 11, it will transition to traditional rate regulation under the OEB.

"To support a smooth trend in annual payments and consistent payments over the life of the asset," the ISO said it will limit the year 11 payments to a percentage increase over year 10.

"So, for example, the contract may limit the filing amount for year 11 to be within 5% of the payment that was made through the IESO contract in year 10," Nicole Kosonen, senior adviser for capacity integration and development, said during the webinar.

By holding developers to proposal costs and schedules, the partial contracting approach will protect ratepayers while working within the existing rate regulation framework, the grid operator said.

It rejected both a "selection only" option, in which it identifies a developer and immediately enters rate regulation under the OEB, and a "full contracting" model, in which the ISO signs a contract with the developer for the life of the transmission asset.

IESO said ratepayers will assume the risk of project scope, changes in law and early termination while developers would assume risks regarding routing, land acquisition, design, construction, operations and financing. The two parties will share risks of *force majeure*, tariffs and inflation, it said.

Indigenous Participation

To encourage Indigenous communities to participate in TSF projects impacting them, the rules allow the communities to engage with multiple bidders, barring developers from signing exclusivity arrangements.

IESO also has proposed that bidders submit an Indigenous Engagement and Participation Plan to identify the "en-

Why This Matters

IESO, which has about 932 miles of new transmission lines planned or under development, says competition will lower costs and produce innovation.

gagement approach and participation opportunities" for impacted Indigenous communities.

"Those that have a higher overall level of Indigenous participation may be scored higher in the IESO's proposal evaluation," the ISO said.

Experience Requirements

To join the TSF-R, prospective bidders must meet requirements for experience and financial capacity.

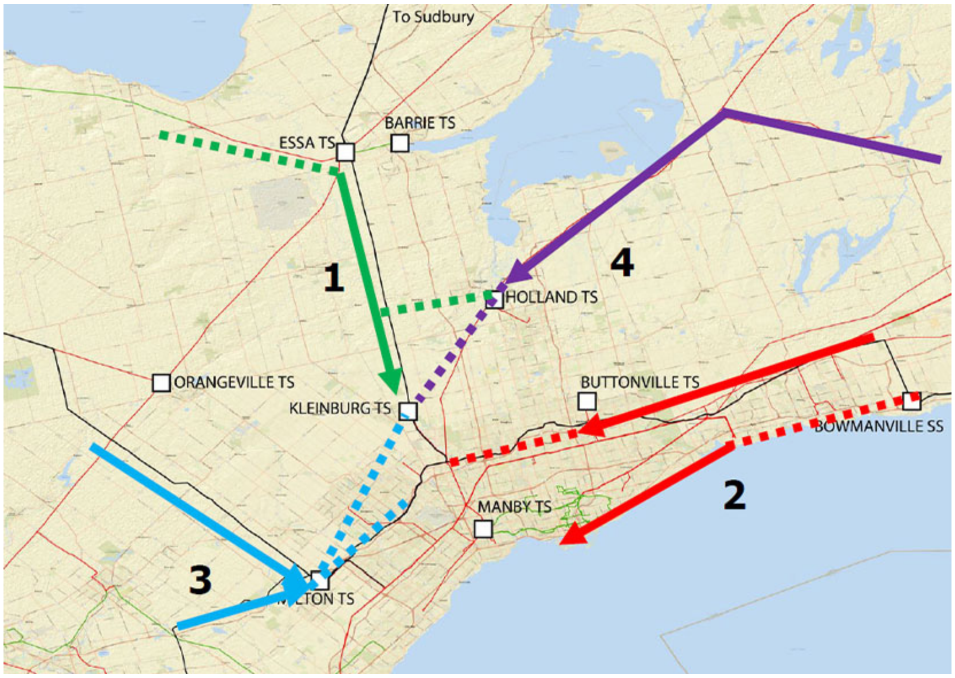
To balance the desire for competition with the need to ensure developers have appropriate technical capabilities, the ISO said it will allow potential bidders to demonstrate their capabilities via the experience of affiliated companies.

The *proposed rules* require the applicant or an affiliate to have built at least two transmission lines of at least 200 kV and 30 kilometers (about 19 miles) within the past 20 years.

FortisOntario, which owns three local distribution companies, was among those calling for crediting companies for their affiliates' experience. In comments submitted in April, the company noted that it is a subsidiary of Fortis, which owns 10 regulated utilities, including ITC, the largest independent transmission company in the U.S. "Without recognizing the value of decentralized companies, the draft rules risk creating barriers for parent companies that, despite lacking a transmission license, possess the scale, expertise and established presence in Ontario needed to deliver reliable and cost-effective transmission solutions," it said.

Feedback to Date

IESO said it had received "broad support" from stakeholders for its proposed TSF-R program rules, although there were requests for greater clarity on efforts to encourage Indigenous involvement.



IESO is considering several new transmission lines into the Greater Toronto Area. | *IESO*

FortisOntario urged the ISO to open competition for projects above 115 kV, saying the competitive plan "currently appears focused on projects above 200 kV."

Some stakeholders requested more clarity on credit rating requirements for smaller or privately held firms. Hydro One said IESO should boost the minimum net worth of proponents not already licensed by OEB as a transmission company to $500 million from its proposed $200 million, noting that the ISO has said the minimum project size for the TSF is $100 million.

"Taking on a project that would involve more than half of the net worth of the entire company could create significant risk for Ontario ratepayers if the project is beset with large budget overruns," Hydro One said.

Next Steps

IESO still has to define the criteria that will be used to evaluate competing proposals, including bid parameters and cost caps.

The grid operator said it seeks feedback on whether its proposed bid structure and risk allocation "strike[s] the right balance between protecting ratepayers while providing an attractive proposition to transmitters and financiers" and how it should evaluate bidders' proposals for providing "meaningful Indigenous economic participation and engagement."

It also asked for ways to reduce bidders' risk premiums and whether it should use a "highly prescriptive approach" to cost-containment or leave it open for bidders to include in their proposals.

Written *feedback* or questions are due to *engagement@ieso.ca* by July 16. The IESO plans to compile answers in an FAQ document.

IESO plans another engagement session in September to discuss its draft term sheet and additional RFP and contract design details. ■

Extreme Heat Triggers Capacity Deficiency in New England

By Jon Lamson

ISO-NE declared a capacity deficiency, implemented a Power Caution and took extra actions to maintain grid reliability during what may have been the highest peak load since 2013, driven by extreme heat and humidity, on the evening of June 24.

ISO-NE entered the day with a slim reserve margin and declared a Power Caution in the early evening "after the unexpected loss of generation left the region short of the resources needed to meet both consumer demand and required operating reserves."

A Power Caution indicates that the RTO can no longer maintain its reserves through "normal measures." ISO-NE lifted it at 9 p.m., after the evening peak had subsided, but maintained a precautionary alert of abnormal system conditions, which was instituted June 23 because of the heat.

Demand peaked at 26,024 MW around 7 p.m. June 24, according to preliminary data from the RTO. This would be the highest peak demand in the region since 2013 and about 200 MW higher than the forecast peak for the day.

Heading into the summer season, ISO-NE *projected* a 24,803-MW seasonal peak in typical weather conditions and a 25,886-MW seasonal peak with above-average temperatures.

The sudden generation loss that triggered the Power Caution may have come from a gas resource; just before ISO-NE issued the power caution, gas generation in the region rapidly declined by about 1,000 MW, according to RTO data. During the peak-load period, natural gas accounted for about 45% of the region's fuel mix, followed by nuclear at 12%, oil at 12%, net imports at 11% and renewables at about 5%.

Behind-the-meter solar also contributed to a significant peak reduction. ISO-NE estimates that demand would have peaked over 28,400 MW without its contributions. BTM solar pushed the peak multiple hours later in the day, from midafternoon to midevening. At 6:50 p.m., with solar production on the decline, BTM solar still contributed to an over-600-MW reduction in the peak.

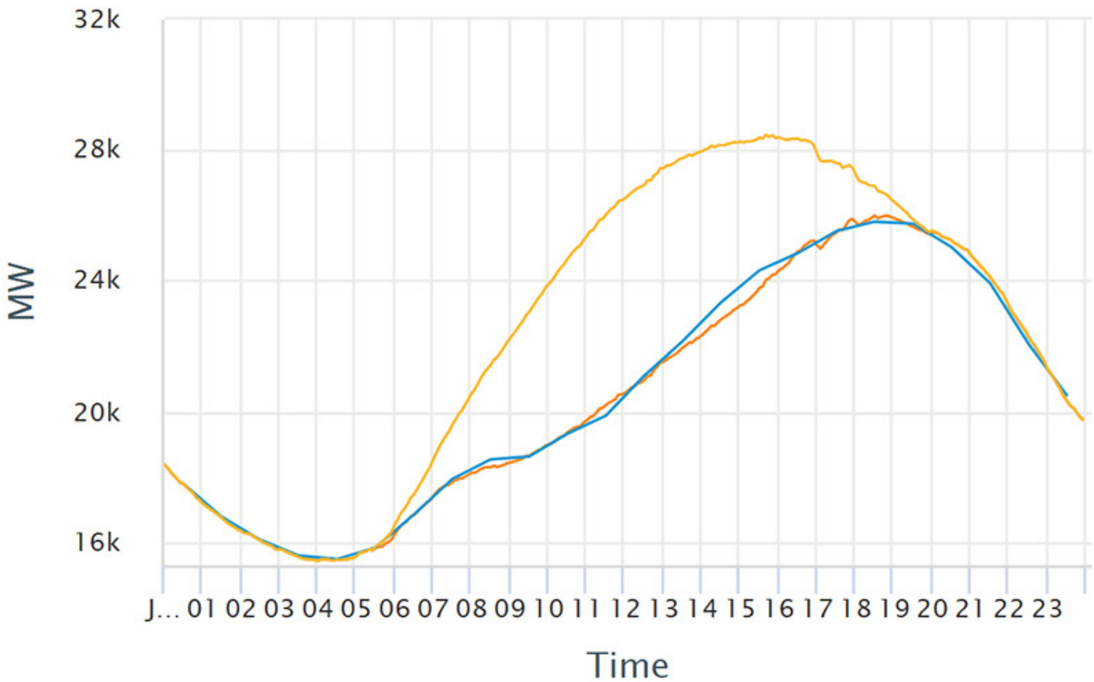
Locational marginal prices spiked during the capacity deficiency, with the hourly Hub LMP reaching $1,110/MWh between 6 and 7 p.m., more than doubling the day-ahead Hub price of $475/MWh for the same hour.

Why This Matters

ISO-NE was able to maintain grid reliability during what appears to be the highest load experienced in the region in over a decade.

The extreme temperatures affected most of the country and caused tight system conditions throughout the Northeast on June 24. NYISO issued an Energy Warning late in the day, while PJM issued a Maximum Generation Alert and MISO remained under a Max Generation Warning. (See related stories, *NYISO Issues Energy Warning as Heat Wave Boils New York* and *MISO Declares Max Gen Emergency in Heat Wave*.)

Across New England, thousands of distribution customers faced power outages amid the heat wave, which brought temperatures as high as 102 degrees Fahrenheit in Boston, marking the *fourth-hottest day* on record in the city. ■



Graph of load (dark orange), forecasted load (blue) and actual load including estimated behind-the-meter solar (orange) | *ISO-NE*

NEPOOL PC Briefs

Annual State of the Market

HARWICH, Mass. — Amid extreme temperatures and the highest peak demand experienced in years, ISO-NE and stakeholders discussed market performance, capacity auction reforms, the RTO's 2026 budget and asset condition spending at the summer meeting of the NEPOOL Participants Committee on June 24-26.

The three-day meeting at a luxury resort on Cape Cod was preceded by the news that CEO Gordon van Welie, who has led the RTO since 2001, will retire by the end of the year. He will be replaced by COO Vamsi Chadalavada. (See *ISO-NE CEO Gordon van Welie Announces Retirement*.)

David Patton of Potomac Economics, ISO-NE's External Market Monitor, presented his annual assessment of the region's markets, which found they "performed competitively" but concluded that "key improvements will be increasingly important in the coming years."

ISO-NE had the highest overall wholesale market costs of all RTOs in 2024 because of high gas costs, Patton said. New England's reliance on natural gas generation has increased in recent years; according to ISO-NE data, gas generation hit a record high in 2024, accounting for 51% of net energy for load in the region. (See *New England Gas Generation Hit a Record High in 2024*.)

Why This Matters

ISO-NE is in a period of significant transition as it faces some of the highest costs in the country and prepares for growing demand, a changing resource mix, and increased variability of both supply and load.

Patton added that New England faced inflated capacity costs because of over-forecast demand in its Forward Capacity Auctions, which is "slow to correct in the [Forward Capacity Market]."

The region also continues to have extremely high transmission rates, which were "more than double the average rates in other RTO markets," Patton said. He noted that the region's transmission investments have led to low congestion costs. ISO-NE continued to have the lowest congestion costs of all RTOs in 2024, estimated to be "8 to 17% of other RTOs per megawatt-hours of load," Patton added.

However, some stakeholders said this calculation of congestion costs does not appear to fully account for transmission constraints in Maine, which have limited the development of renewables and are the target of the first ISO-NE Longer-Term Transmission Planning solicitation. (See *ISO-NE Releases Longer-term Transmission Planning RFP*.)

Patton also expressed concern about a lack of liquidity in ISO-NE's day-ahead market because of "inefficient allocation of costs to virtual transactions."

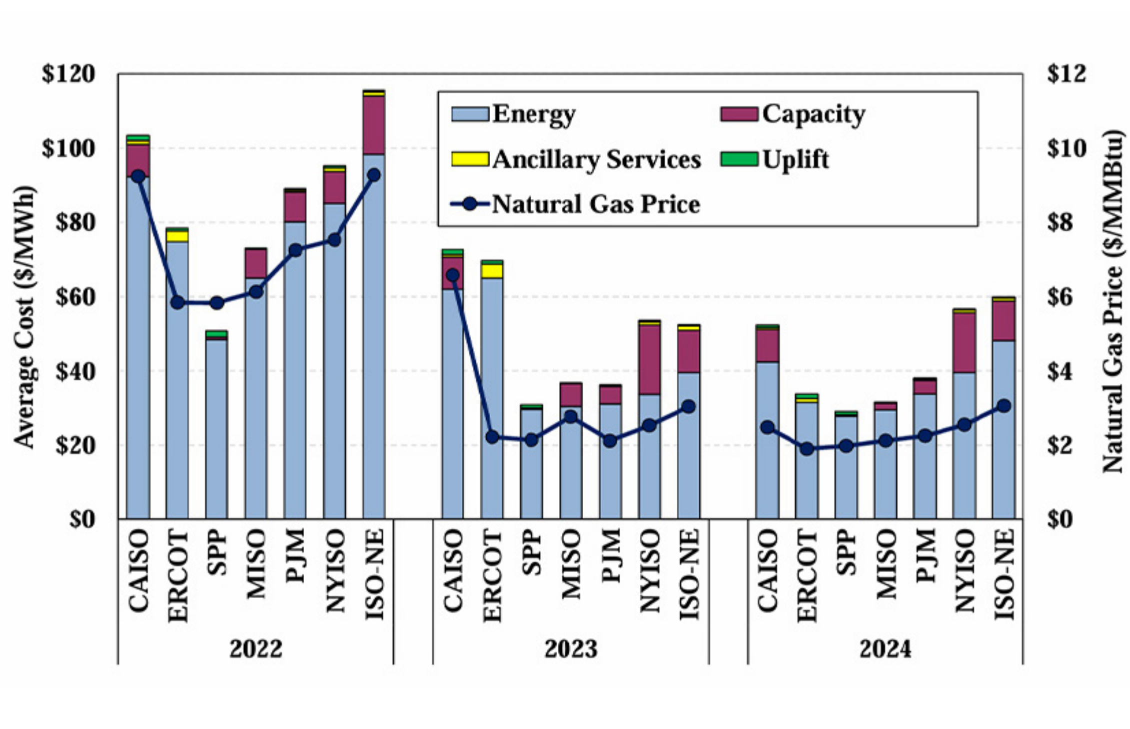
Patton supports ISO-NE's ongoing efforts to overhaul its capacity market, which are focused on improving resource accreditation, reducing the time between auctions and capacity commitment periods (CCPs), and splitting CCPs into summer and winter seasons.

He also called for a reduction in ISO-NE's Pay-for-Performance (PFP) rate, which he said often overstates the value of reserves and could cause the premature retirement of some fossil units. He said the RTO should align PFP charges with the severity of reserve shortages and charge exporters the PFP rate.

Reflecting on two capacity deficiency events in the summer of 2024, Patton said "extraordinary prices" caused significant charges imposed on steam turbine and combined cycle plants, "most of which were available but not committed in the day-ahead markets."

High PFP charges on resources that were not committed in the day-ahead market could cause "lower net revenues that may lead to premature retirements" and "inefficient incentives to self-commit such resources," Patton said.

As states look to transi-



RTO all-in market costs per MWh | *Potomac Economics* tion away from fossil generation, Patton concluded the region is "well positioned to handle the renewable transition" but recommended the RTO develop a "a look-ahead dispatch model to address ramp needs and [the] optimization of storage resources."

Multiyear Road Map

Chadalavada outlined some "key future focus areas" for the RTO over the next few years, including the development of "forward-looking intraday market-clearing and pricing systems," intended to help optimize storage deployment and meet increasing ramping requirements.

"To cost-effectively address operational uncertainties in a dynamic power system, costs will need to be incurred now to position the system with sufficient flexibility later," Chadalavada said. "This will require new real-time, 'multi-interval' optimization and pricing algorithms incorporating probabilistic forecasts."

Chadalavada said ISO-NE aims to develop probabilistic forecasts for load and renewable production, which should help the RTO manage increasing uncertainty on the system.

He said ISO-NE is researching methods for multi-interval pricing and probabilistic forecasting, and said the RTO "may recommend a sequence of phased and interdependent market enhancements over the course of this initiative."

Other focus areas Chadalavada highlighted include system planning coordination, modeling of inverter-based resources, resource adequacy and cybersecurity.

2026 Budget

ISO-NE outlined its initial 2026 budget proposal: a revenue requirement of $315.2 million, which would be a $4 million increase over the 2025 requirement.

This includes a $15.6 million reduction associated with the annual revenue true-up. Without the true-up, the 2026 budget is 1.8% lower than ISO-NE initially projected in 2024.

"The budget for 2026 represents the ISO's commitment to supporting the region as it continues to experience an evolving resource mix and changing customer use patterns, ensuring that markets and grid operations are efficient and reliable," said Kelly Reyngold, director of accounting.

Notably, the budget "includes 'placeholder' funding for asset-condition review work that will only be used for this purpose and, if not needed, will not be reallocated for use elsewhere."

Earlier in 2025, ISO-NE announced it's open to taking on a nonregulatory role in reviewing asset-condition spending, responding to state and consumer advocacy concerns about a lack of transparency and oversight on the projects. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Chadalavada said it likely will take about 18 months to develop in-house asset-condition review capabilities, but that ISO-NE hopes to hire a consultant to help review the most important projects in the interim period. He said the RTO is working with the transmission owners to establish the criteria for reviewing projects in this interim period and eventually will include all stakeholders in these discussions. ■

— Jon Lamson

MARC Confronts Public Perception, Affordability, 'Post-DEI' and Nuclear Options

By Amanda Durish Cook

Why This Matters

It wouldn't be an annual state regulatory conference without a discussion on load forecasts, but MARC 2025 also featured a diverse slate of topics.

INDIANAPOLIS — The 2025 Mid-America Regulatory Conference tackled themes on meaningful public engagement, nuclear options, bill affordability, and diversity, equity and inclusion (DEI) programs falling out of favor.

Panelists at the June 22-25 conference appeared to agree that focus needs to stay on underserved communities; affordability should be top of mind; and microreactors will make an appearance to handle load growth in the next decade.

Andrew Valainis, an associate at the Regulatory Assistance Project, said people tend to only get interested in electricity when their rates go up.

Valainis said commissions should create public access and engagement plans as part of annual work plans. He also said that "public notice" and "publicity" for meetings are two different things. While a notice is a legal formality, ensuring that at least some of the public is aware of a consequential meeting is a different matter.

Despite more ways than ever for the public to participate in the regulatory process, "people don't really care," said Sarah Moskowitz, executive director of the Illinois Citizens Utility Board.

"More often than not, it's still all of us talking to each other," Moskowitz said, gesturing to the audience.

She asked regulatory staff to think about why they want public involvement: to "check a box," generate ideas, get a bead on sentiment, or if they really want public voices to shape the outcome of a proceeding.

"We can't have this conversation without being honest about what we want from the public," Moskowitz said. She also said people tend to show up when they are angry. She said if commissions want participation on a "Wednesday night" for an "esoteric, boring" meeting, the public needs to be educated on the regulatory process.

Moskowitz also said it's "a lot" to expect frontline groups who have previously been involved in commission matters to continue to show up regularly to meetings. She questioned whether commission staff should try to engage the public directly or if public input can be solicited through community-based groups. Either way, she said, regulatory staffs should conduct more community outreach and make webpages easier to navigate with plain language.

Moskowitz said consumer advocate groups "can't do it all" and said they need some help from the states.

Former MISO COO and President Clair Moeller had a somewhat darker take on public participation. Moeller said he learned throughout his career that there's a difference between "the public interest and the interested public."

Several state commissioners participate in an "Ask Me Anything" session at MARC 2025 on June 25 in Indianapolis. | © *RTO Insider*

"People who are educated and have a voice have an outsized influence," he said, mentioning "well-funded" groups that pay individuals to speak at meetings and submit comments. The regulatory processes seem set up to be confrontational and invite litigation because of their opacity until outcomes are announced. "That's something I've noticed," he said.

Moeller urged industry players to speak in plain language and not use technical terms. However, he said, "the fact that a lot of these cases end up in litigation" cannot be ignored and has a chilling effect on openness. He recalled he once gave a presentation to answer questions, and the PowerPoint presentation showed up as an exhibit in a state rate case before he could make the drive home.

He urged the industry to create an environment where "it's safe to answer the question."

During a "fireside chat," FERC Commissioner Lindsay See and Indiana Utility Regulatory Commissioner Sarah Freeman both said they have noticed an uptick in legal challenges to commission orders in recent years.

Freeman said she hoped the increased activity is a result of a more informed public. "That matters so much for the outcomes we deliver," she said.

See said that while clerking for Judge Thomas B. Griffith, of the D.C. Circuit Court of Appeals, she was "struck" by the real-world implications of complex law interpretation. See said she is a huge believer in public service and state service and "genuinely considers" FERC in a partnership with the states.

"I learned a lot about how important the state voice is," See said of her time as West Virginia Solicitor General.

See said she appreciated the divergence of policy in the midcontinent region and assured attendees that she reads states' individual comments on FERC filings.

DEI in Actions, not Words

The recent national political backlash to DEI hiring practices and considerations in billing did not deter some panelists from appealing for their continuation.

Michelle Fleurantin, a fellow at the Institute for Policy Integrity think tank at the New York University School of Law, pushed back against the notion that the energy industry exists in a "post-DEI" world. However, she said it's "scary and challenging" for regulators to conduct targeted outreach for historically disadvantaged ratepayers right now.

Fleurantin said regulators may have to confront a "sticky situation" in which they publicly break with messaging from the federal level and announce intentions to assist burdened communities.

Fleurantin asked regulatory staffs to reflect on the difference between the essential need to hear diverse voices in decision-making and reacting to an "unreasonable chilling effect" from state and federal lawmakers. She said it's necessary for regulators to consider equity and inclusion in their work to figure out if initiatives "actually work on the ground" and discern whether decisions could risk putting "large swaths" of a population in danger.

FERC Commissioner Lindsay See (left) and Indiana URC Commissioner Sarah Freeman | © *RTO Insider*

"DEI is obviously super politicized, but we need to home in on outcomes," Fleurantin said.

Fleurantin said continuing to set aside a significant percentage of investment for underserved communities should continue. She said although it's by now a cliché to recommend people call their elected officials, she advised them to do so to encourage continued funding. However, she allowed that it's difficult for the public to understand how to become involved in utility decisions. "It's very opaque; it's very technical; there's definitely a high barrier to entry in these spaces."

A June 23 panel on public engagement | © *RTO Insider*

Panelists also touched on how DEI works in hiring practices in today's political climate.

Tim Simon, principal and founder of TAS Strategies and former member of the California Public Utilities Commission, said his firm is currently advising clients that there is a difference between a federal mandate and state ambitions.

"Once upon a time, they called them 'states' rights,'" he said and noted that there's now a "friction" between the federal government and some states. He noted that Indiana Gov. Mike Braun broadly replaced the DEI efforts in the state with a "merit, excellence and innovation" philosophy.

"I don't think it's time to really pull out our bayonets. I think we have more in common," Simon said. He stressed that "our workforce and our suppliers are an issue of national security" and said skilled workers across the country can fill needs. He said the best candidates can earn jobs while simultaneously satisfying divergent aims from states and the federal government.

"I think we have to get away from the nomenclature and do the work," he said, adding that regulators have more work to make sure rates are just and reasonable. He said more and more households are being pushed into low-income status, which isn't sustainable for the utilities' business model.

"Do we have a diverse pool of candidates every time we have an opening? Yes," Commonwealth Edison CEO Gil Quiniones said. He said those diverse candidates are then sized up by a diverse hiring committee, with the best candidate selected.

"I would stack up our team against any utility in the country," he said.

Affordability Concerns

RMI Senior Associate Maria Castillo said research shows that U.S. households are increasingly forgoing other expenditures to afford their energy bills.

Oracle Director of Regulatory Affairs Julia Friedman agreed that there is an energy affordability crisis. She said when electricity bills rise 30 or 40%, it pushes a lot of customers who have never needed bill assistance into needing help. However, she said utilities' increases are coinciding with a "stagnation" in customers turning toward assistance programs.

Friedman said according to Oracle's research, customers say their mortgage or rent payments and utility bills are the household expenses that they feel they have the least amount of control over.

"We have to overcome … customers feeling like they have no control over their bills," Friedman said. She said utilities can provide an online one-stop shop for discounts and time-of-use programs.

Chris Villarreal, an associate fellow at R Street Institute, said a state-funded consumer advocate coupled with state regulators can apply "some amount of pseudo-competitive pressure" on monopoly utilities to keep their rates in check.

Missouri Public Service Commissioner Maida Coleman (left) and ComEd CEO Gil Quiniones | © *RTO Insider*

Laura Rauch, MISO | © *RTO Insider*

Villarreal said customers now have more viable options available for them to supplement their supply, mentioning rooftop and community solar.

"There's not one place that provides the electricity. Now, there's one distribution system that delivers the energy," he said.

Julia Selker, of Grid Strategies' Working for Advanced Transmission Technologies Coalition, said grid-enhancing technologies can pull more monetary value from the grid and help lower bills.

Selker said if transmission operators were to place a dynamic line rating on a highly congested line, it would pay for itself in a weekend. She said even a "walking" wind speed can cool lines down enough to carry 30% more power.

Selker said at this point, utilities' hesitancy to deploy grid-enhancing technologies is only "cultural."

Once Again, Load Forecasts

No industry conference is complete in 2025 without a debate on load growth, and MARC 2025 delivered.

RMI Principal Lauren Shwisberg said load forecasts should be taken "seriously, not literally."

She said RMI has found that historically, utilities over-forecast their load by about 17%. She said while under-forecasting poses risks to reliability, over-forecasting threatens affordability.

"We're operating at margin, and we're doing a pretty darn good job," MISO Executive Director of Transmission Planning Laura Rauch said. But Rauch said operating without the 25% cushion that existed when she was a "baby engineer" makes grid planning more difficult.

Rauch said the urgency surrounding the need for construction often reminds her of a saying that "the best time to plant a tree was 20 years ago if you want the shade now."

"The next best time is today," she said, later adding: "You can't piecemeal your way to serving a city-size load."

Even with a co-located generation plan, data center loads largely plan to draw on the system when their own generation is unavailable and inject into the grid when they aren't fully using their on-site power source, she said. Utilities, data center customers and MISO need to match "desires and incentives with commitments" to weed out speculative announcements.

Google's Tyler Huebner addressed the possibility that "six to 10 data centers might become two to three."

"I don't want to give the idea that we're just playing around with load forecasts. The reality is that it's very complicated to build a data center. … It's not malfeasance, and it's not [us] trying to be a bad actor in any way," Huebner said. He said data center developers must consider the most opportune spots to connect, the availability of generation and optimal siting.

MISO Senior Vice President Todd Hillman said the energy industry is learning to be "dynamic and disruptive" with new technology avenues amid load pressure. He noted that about 97% of MISO's interconnection queue is solar, wind and battery storage. But he also said MISO is lacking about 31 GW in new generation projects that should have been online by now but are stalled.

"Imagine 31 more gigawatts today. The summer is still going to be hot, but it's going to be a different story in terms of what we can do," Hillman said. He said the holdup can be traced to five causes: "People, parts, permitting, politics and pricing issues."

"Our industry represents 5% of the economy, but it's the first 5% of the economy," ITC Holdings CEO Linda Apsey said.

Apsey noted that the American Society of Civil Engineers rated U.S. energy infrastructure a "D+," which isn't going to cut it for a grid that will see rising demand from data centers and manufacturing onshoring. Apsey said the score is the same as 20 years ago, despite pains since then to refurbish and build out the aging grid.

"Time is of the essence, and reliability and resiliency is of the utmost importance," she said.

Apsey said the last time the country saw material load growth was in the 1970s when a wider selection of home appliances and home air conditioning took off.

She said utilities don't have a choice but to accept the economic opportunity that data centers present or risk losing them to other states or regions. "For them, it's a race. They have to be first to market."

The Nuclear Option

"I don't think you can walk into a room and not hear about data center growth," Constellation Energy Vice President of Strategy and Growth Colleen Wright said.

Wright said there's currently a "perfect storm" of conditions that can help get new nuclear built to replace baseload generation.

"I don't think that window is open forever," she added.

Timothy Grunloh, principal research scientist at the University of Illinois Urbana-Champaign, said he hopes the university's plans for a research reactor can show that microreactors "can be built with a predictable schedule; a predictable budget."

Grunloh is helping to develop a modular microreactor to figure out whether permitting, siting, safety reviews, supply chain or regulatory processes present the biggest barrier to building new nuclear generation. The demonstration reactor will rely on tri-structural isotropic fuel particles, which consist of uranium-based kernels that use graphite as a moderator.

A decade ago, he said he would have characterized the Nuclear Regulatory Commission as a "bogeyman" that tries to "trip up" developers. However, he said his experience working with the NRC is the opposite and said staff are all about, "How do we get you to 'yes' safely?"

Grunloh said so far, his team has found that the supply chain presents the biggest challenge.

"Beyond that, all roads go through public perception," he said. Grunloh said the public's recent softening toward nuclear energy has thus far been hypothetical. He said that positivity may change once some reactors become reality. Grunloh added that small reactors could be ready in commercial use sometime around 2029.

In a later talk, Gov. Braun said he couldn't think of anything else "tested to the degree" as nuclear has been to provide future baseload power. He said he thinks U.S. Energy Secretary Chris Wright and the Trump administration should be able to clear regulatory obstacles to scale up new nuclear quickly. In response to an audience question, Braun said he's open to experimenting with small modular reactors at the state's military sites.

Braun said he viewed himself as a "conservationist" but in a "practical" way. He said he saw an ongoing spot for coal in Indiana's energy mix until enough batteries or nuclear generation can be installed. ■

FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism

By Amanda Durish Cook

FERC has found that MISO and SPP's 100% cost allocation to generation for the pair's $1.7 billion Joint Targeted Interconnection Queue (JTIQ) transmission portfolio remains appropriate (*ER24-2797-001, et al.*).

In an order issued at its monthly open meeting June 26, the commission rejected arguments from a group of clean energy organizations that took issue with the 100% allocation to interconnecting generation, and Arkansas and Mississippi regulators, who criticized the backstop feature that allocates costs to load if the lines aren't fully subscribed. It ruled that it continues to find that the JTIQ cost allocation is just and reasonable.

MISO and SPP won approval from FERC in late 2024 to fully allocate the costs of the JTIQ portfolio to interconnecting generation assessed per megawatt. The RTOs initially planned to use a split involving 90% to generators and 10% to load, but they abandoned the approach after the U.S. Department of Energy announced that the portfolio would receive $464.5 million from its Grid Resilience and Innovation Partnership (GRIP) program. (See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.) Under the approved allocation, load will act as a temporary backstop for their share of the costs until enough new generation projects commit to the lines and pick up the tab for construction.

Why This Matters

Neither clean energy groups nor MISO South regulators could convince FERC that MISO and SPP should use an alternate cost allocation for their $1.7 billion Joint Targeted Interconnection Queue transmission portfolio. Generation developers still are poised to take on 100% of portfolio costs.

© RTO Insider

The American Clean Power Association, Solar Energy Industries Association and Advanced Power Alliance argued that the JTIQ's allocation, where generation pays all line costs and load pays nothing, ignores that load would "undeniably benefit" from the transmission. They also said the commission overlooked that new interconnection customers aren't the "legally relevant cause" of the JTIQ portfolio, nor its sole beneficiaries. The groups said FERC abandoned its cost-causation principles and violated the Federal Power Act and the Administrative Procedure Act by greenlighting the allocation.

FERC said it approved the allocation "based on the unique set of facts and circumstances of the proposed JTIQ framework" and cited "'massive amounts of interconnection requests,' the lack of transmission system capacity at the seam to accommodate this volume of interconnection, the significant incremental cost of constructing network upgrades under the RTOs' affected-system study process … as well as the $464.5 million DOE GRIP funding, which covers approximately 25% of the costs that will be allocated to the interconnection customers."

The commission said MISO and SPP's JTIQ studies and economic theory show that interconnection customers will benefit from more certain and smaller upgrade costs and a reduced interconnection timeline.

"We continue to find that, based on substantial record evidence, interconnection customers are the primary beneficiaries of the JTIQ upgrades … and therefore should bear the primary responsibility for the … capital costs. In contrast, load still receives 'some benefit' and is correspondingly reasonably allocated more limited, potentially temporary, cost responsibility through the backstop funding mechanism," FERC wrote.

The commission added that MISO and SPP can continue to use their load as a backstop cost allocation for JTIQ lines despite the Arkansas and Mississippi public service commissions' argument that MISO could not prove enough benefits would flow to MISO South from JTIQ lines to justify a footprint-wide backstop allocation.

Continued on page 31

Half of MISO States Oppose DOE Order on Campbell Plant, Add Rehearing Request

By Amanda Durish Cook

Why This Matters

A razor-thin majority of members of the Organization of MISO States said the Department of Energy's order to pause a Michigan coal plant's retirement infringes on states' jurisdiction and relies on "undependable" reliability assessments from NERC.

Half of the Organization of MISO States said the U.S. Department of Energy's directive to keep the J.H. Campbell coal plant in Michigan operating through late August wasn't well reasoned, violates the law and tramples on state-jurisdictional planning.

OMS registered a June 23 *request* for rehearing, adding to a growing pile of challenges to DOE's order to keep Consumers Energy's 63-year-old J.H. Campbell coal plant from retiring as scheduled until Aug. 21. (See *Order to Keep Campbell Plant Running Challenged at DOE and FERC*.)

OMS said DOE relied on an "overly broad and speculative interpretation" of what composes an emergency under the Federal Power Act and invoked federal authority when there was no supply squeeze. It pointed out that it was the first time DOE used such an order outside of a severe weather event or emergency and said it improperly interfered with state and regional planning processes.

"This expansive use of emergency powers sets a troubling precedent, enabling intervention in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO and states processes, and likely exposes ratepayers to costs that should not be borne. Such preemptive action risks undermining the credibility of future emergency orders, distorting market signals and eroding the statutory balance between federal and state authority," OMS wrote.

OMS said DOE didn't consult with MISO, Consumers Energy or the Michigan Public Service Commission or other state regulators responsible for integrated resource planning before issuing the edict. It also said DOE's move was an arbitrary and capricious action under the Administrative Procedures Act.

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

OMS asked DOE to vacate its May 23 order or revise it if DOE can demonstrate a reliability need after subjecting the order to stakeholder scrutiny and a more open process.

The public service commissions of Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota and Wisconsin signed off on the rehearing request. The New Orleans City Council also added its endorsement.

MISO South regulators from Arkansas, Louisiana, Mississippi and Texas abstained from voting to support the filing in addition to the public service commissions of the Dakotas. The Manitoba Public Utilities Board and the Montana Public Service Commission, on the other hand, didn't participate in a vote on the request or become involved in drafting the OMS filing.

OMS said this year's resource adequacy survey in partnership with MISO, the 2025/26 MISO capacity auction, MISO's summer readiness assessment and Consumers Energy's plan "all do not indicate a regional reliability emergency, shortfall or an unmet reliability criterion that justifies reversal of a planned and approved resource retirement." (See *MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey*.)

It pointed out that MISO's capacity auction cleared beyond a one-day-in-10-years reliability standard. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

OMS said DOE failed to show a "dependable and comprehensive reliability assessment" that shows MISO is faltering. NERC's Long Term Reliability Assessment (LTRA) — the primary data the DOE used to show MISO in crisis — should not be relied upon, OMS said. The organization said NERC employs inconsistent data collection between RTOs, unverified data inputs and "dubitable" evaluation metrics.

"At their core, the NERC LTRA and seasonal assessments are undependable because they lack stakeholder input and verification. The NERC LTRA and seasonal assessments have been called into question over the past several years, as the assessments have gained traction and increased use, questions from MISO, multiple states and, most recently, MISO's Independent Market Monitor."

NERC earlier in June said it would *downgrade* MISO's risk level from "high" to "elevated" after MISO's IMM accused the reliability regulator of failing to distinguish between installed capacity with unforced capacity when calculating the assessment's totals. (See *MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot*.)

"More accurate, timely and relevant information was and is available and was not expressly reviewed or contemplated by the DOE order, and no avenue exists to allow this more relevant information to be considered by DOE," OMS wrote.

Finally, OMS said DOE's lack of a cost recovery framework for the 1.6-GW Campbell plant's monthslong extension creates "legal, jurisdictional and equity concerns." DOE created a cost-intensive action through its order, OMS said, yet tasked FERC with creating a means to assign costs to reimburse Consumers Energy. It said parties that don't benefit from the plant's paused retirement nevertheless could help fund it.

MISO has not designated the plant as a system support resource necessary for grid reliability and isn't equipped with any rules on the books to allocate the costs of keeping the plant running. ■

FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism

Continued from page 29

"The RTOs have shown that the entirety of MISO will benefit to some degree from the high-voltage transmission facilities in JTIQ portfolio No. 1 that will enable the interconnection of generation, regardless of the subregion in which these facilities are located," FERC said.

The commission said that despite MISO's Midwest-to-South transfer limit, transmission customers in both regions would receive "minor and incidental benefits from increased transmission system robustness" and "more timely interconnection of new generation capacity that enables lower production cost generation to access the entire MISO market." FERC also said lower congestion at the RTOs' seam could lower MISO's congestion payments to SPP.

FERC cited an SPP study that showed that a swifter interconnection of projects at the seam would boost reliability and confer almost $176 million of adjusted production costs benefits to the RTOs, with $76.5 million benefiting MISO.

FERC echoed MISO and SPP that the backstop allocation is "highly unlikely" to become the permanent allocation based on the "substantial" amount of proposed generation in their interconnection queues and their forecasts that call for increasing load.

MISO generation developers, meanwhile, have expressed disdain for the JTIQ cost allocation, saying the additional studies the RTO tacked onto the process could send cost assignments as high as they were under its former affected-system study process with SPP. (See *MISO Gen Developers Sour on RTO's JTIQ Cost Allocation*.)

Generation developers also don't believe GRIP funding is assured under the Trump administration. National Grid Renewables in May told MISO the "certainty of this funding has come into question under the current presidential administration." The company said allocating costs solely to generation was only approved because the grants would fund almost half of the JTIQ portfolio. National Grid predicted challenges in construction timelines if grant funding is revoked and generators are left to pay more than what they estimated.

MISO responded at the time that it was not expecting JTIQ funding changes and said DOE had not indicated that GRIP funding is in jeopardy. However, the RTO added that "JTIQ is not contingent upon the receipt of GRIP funding." ■

FERC Says MISO's Interconnection Compliance Lacking, Approves General Design

By Amanda Durish Cook

Why This Matters

MISO must make a few revisions to its Order 2023 compliance before it can pass FERC inspection.

FERC told MISO it needs a few more edits to its queue rules to be compliant with the commission's wide-ranging order to streamline generator interconnection.

FERC decided MISO is free to maintain its three-phase approach to interconnection queue studies under Order 2023. The commission said MISO's setup already used a cluster study process with a first-ready, first served philosophy for projects in accordance with its order and therefore didn't require a transition plan. FERC also said MISO's site control requirements, milestone payments, withdrawal penalty fees and study deposits were appropriate under Order 2023 (ER24-2046).

FERC issued Order 2023 in July 2023, seeking to clear backlogged interconnection queues by implementing a first-ready, first-served cluster study process; increasing interconnection customers' financial obligations; and penalizing grid operators for missing study deadlines. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

However, FERC in a June 26 order said some details of MISO's plan need refinement. It said MISO fell short in describing how it would allocate the costs of different types of network upgrades. FERC noted that MISO's plan didn't distinguish between thermal and non-thermal network upgrades, though its business practice manuals make a distinction.

| Shutterstock

The commission said MISO didn't include a plan for allocating the shared costs of cluster studies and ordered MISO to revise its interconnection procedures to include an allocation that assigns between 10 and 50% of study costs per capita, with the remaining 50 to 90% allocated *pro rata* by megawatt.

FERC said MISO should have committed to updating a points-of-interconnection heat map after the final system impact study takes place. MISO proposed to provide the heat map one time after it completes a preliminary system impact study. FERC said without a heat map update after the final system impact study, prospective interconnection customers might rely on outdated information to decide whether to enter their projects.

The commission said MISO needed to eliminate the term "reasonable efforts" in a section on completing affected system studies and preparing a final report.

Order 2023 ended a "reasonable efforts" standard on interconnection studies. Instead, the order requires transmission providers to meet fixed study deadlines and enacts financial penalties for delays.

FERC said MISO must remove a provision that multiple interconnection customers must form a common business entity before they could share a single interconnection request. FERC said multiple interconnection customers that have a contract or agreement can co-locate and share a single interconnection request without creating an LLC.

The commission also said MISO should not have included steps that allow a transmission provider to conduct extra studies to assess a request for surplus interconnection service. FERC said the additional measures aren't necessary under Oder 2023 and rejected them without prejudice to MISO proposing them in a future filing.

Finally, FERC ordered MISO to define several terms it used throughout its filing and rephrase other parts of the plan. MISO has 60 days to make the changes. ■

NYISO Issues Energy Warning as Heat Wave Boils New York

By Vincent Gabrielle

NYISO issued an Energy Warning late June 24 as New York began to finish its third day of intense heat.

The ISO had issued an Energy Watch earlier in the day, signaling that operating reserves were expected to be lower than normal for longer than 60 minutes. As temperatures climbed past 100 degrees Fahrenheit downstate and in New York City, the state's grid was operating normally but reserves were declining, the ISO said in a statement.

Around 7 p.m., however, NYISO issued the warning, indicating reserves had dropped below 1,965 MW and are not expected to recover for at least 30 minutes. The ISO could begin shedding load if demand isn't lowered or additional supply cannot be added, it said, asking customers to reduce their consumption if possible.

The ISO will issue an Energy Emergency Alert if reserves drop below 1,310 MW.

At the time of the warning June 24, the marginal cost of energy was nearly $1,400/MWh, with locational-based marginal prices in the Long Island zone at nearly $2,700/MWh.

Why This Matters

A severe heat wave has caused price spikes and dropped customers across New York state.

Utility Actions

To combat high demand, PSEG Long Island activated its Smart Savers Thermostat Program, adjusting the thermostats for approximately 40,000 customers. The program load shifts energy consumption during peak by pre-cooling homes in the afternoon before people return from work and school. PSEG Long Island told *RTO Insider* that it anticipates shaving 60 MW off the forecasted peak demand.

Elevated temperatures and elevated demand caused roughly 7,000 people to lose power in the Albany area June 23. National Grid said elevated heat had caused a myriad of wire connection and transformer failures.

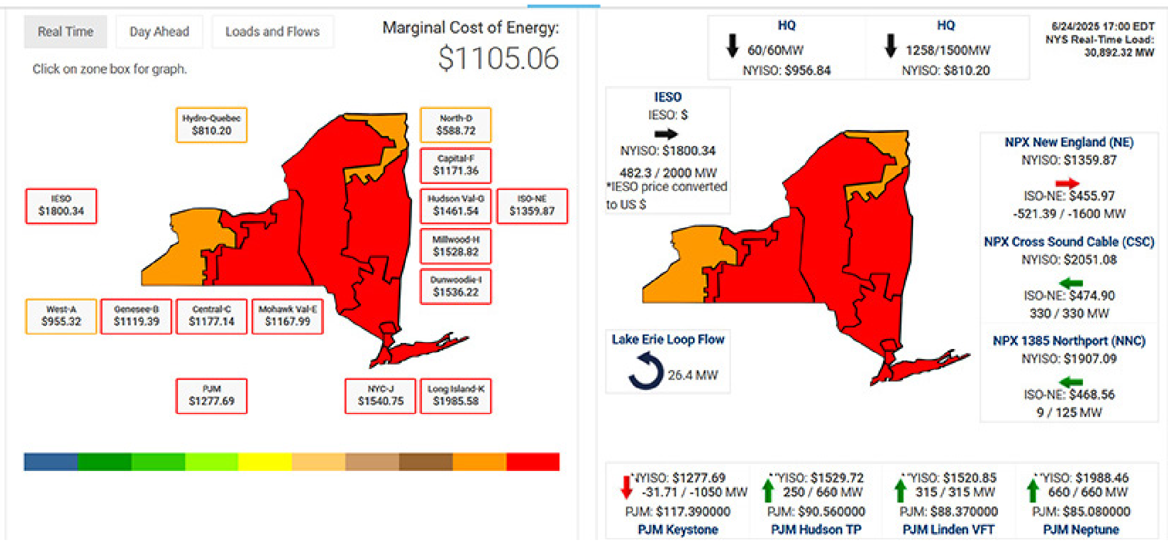
"Overall, the outages we have seen yesterday and today have been repaired in hours, not days," National Grid spokesperson Patrick Stella told *RTO Insider*. "The outages have been limited and scattered across the upstate New York service area."

Consolidated Edison told *RTO Insider* that it had restored power to roughly 79,000 customers in New York City since the heat wave had begun, with an average service interruption time of 4.5 hours. These outages were concentrated in Queens and Brooklyn, which is served heavily by an underground system more susceptible to thermal stress caused by prolonged high demand than the overhead system, Con Ed President Matthew Ketschke told local news.

In Central New York, Oneida County experienced tens of thousands of outages during the heat wave, but this was not from the heat itself. An EF1 tornado (86 to 110 mph) struck June 22 and downed more than 120 distribution poles, according to a National Grid press release. While service had been restored to 90,700 of the customers that lost power, more than 10,000 remained without as the heat wave struck.

National Grid dispatched 2,500 linemen and foresters to repair the damage and is offering public cooling stations to customers affected by the heat. Heat has slowed some recovery efforts.

"We are taking precautions to ensure the health and safety of our crews, such as frequent cooling and hydration breaks," said Jared Paventi, a National Grid spokesperson. "We're cognizant of the stress on our customers as they enter their third day without electricity and AC, and we're doing everything we can to restore power as quickly and safely as possible." ■



NYISO prices around 5 p.m. ET | *NYISO*

NYISO BIC & OC Briefs

Committees Approve Updates to ROFR Implementation

The NYISO Business Issues Committee and Operating Committee approved without objection governing document revisions that would implement transmission owners' *right of first refusal* in the ISO's planning processes at their meetings June 16 and 20, respectively.

FERC in 2021 ruled that New York TOs have a federal ROFR over transmission upgrades to their facilities and in 2022 approved tariff revisions implementing a ROFR for those that are part of another developer's public policy transmission project under Order 1000. (See *FERC Approves ROFR for NY Transmission Upgrades*.)

But those revisions did not include projects selected by NYISO's own reliability and economic planning processes that include ROFR-eligible upgrades. The approved proposal would revise tariff attachments P, Y and FF to implement that.

The proposal now goes to the Management Committee for its June 30 meeting. If approved by the MC and the Board of Directors, NYISO anticipates filing with FERC in July.

Other BIC Action

The BIC also passed a pair of motions unanimously.

The committee recommended that the MC approve tariff *revisions* to support NYISO's Joint Operating Agreement with PJM in anticipation of the activation of the Dover phased angle regulator. The Dover PAR station is part of the *AC Transmission Segment B public policy transmission project*, which is intended to reduce transmission congestion between the Albany area and New York City. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

Stakeholders also passed a motion to recommend approving changes to the tariff to implement the Market Purchase Hub Transactions project. The market design would allow *trading hub energy owners* (THEOs) to purchase and sell power on the NYISO day-ahead market to settle imbalances.

System Impact Studies

The OC also unanimously passed a pair of system impact study reports for two interconnection studies.

One of these, the POWI Project, would draw 50 MW continuously to the Port of Coeymans to support the port's upgrades to service the offshore wind industry. (See *Siemens Gamesa Plans OSW Nacelle Factory in Upstate NY*.) The SIS found there would be no adverse impacts on the local grid. The good-faith cost estimate for the necessary upgrades was found to be $76.48 million.

The other study was for Beowulf Energy's Cayuga Compute project, a large data center expansion at the site of a retired coal plant. The project will boost the data center's load from 50 MW to 138 MW.

The data center supports artificial intelligence computation. The SIS found that the project could cause thermal and voltage violations but they could be mitigated with operating procedures and several upgrades to the local grid. Combined, the local upgrades would cost approximately $15 million. ■

— Vincent Gabrielle

© RTO Insider

NYPA Raises Concern About Large Loads Suddenly Ceasing Operation

The most prolific worry about large load facilities like data centers is how to power them, but the New York Power Authority raised a new concern at the NYISO Budget & Priorities Working Group's meeting June 24.

When working with a large load customer's interconnection, NYPA noticed an *issue* in the ISO tariff that would arise if such a customer ceases operation, creating a "substantial" financial risk to other load-serving entities, the utility's Tony Abate said.

Because NYISO's minimum unforced capacity is constant, "any remaining capacity obligation (i.e., the departing customer's ICAP tag) is spread over all remaining load in the transmission district for the remainder of the capability year," he said.

Typically, loads that disconnect mid-CY are negligible; but data centers disconnecting would cause a problem, Abate argued. Other LSEs in the district may not have a mechanism to protect themselves from the financial risk associated with the reallocation of UCAP should a major customer leave, he said.

NYISO and NYPA had argued about tariff interpretations until the ISO asked it to come forward with a market project, Abate said.

"We see this as being similar in kind of intent with the … large load interconnection project, which NYISO has prioritized," Abate said.

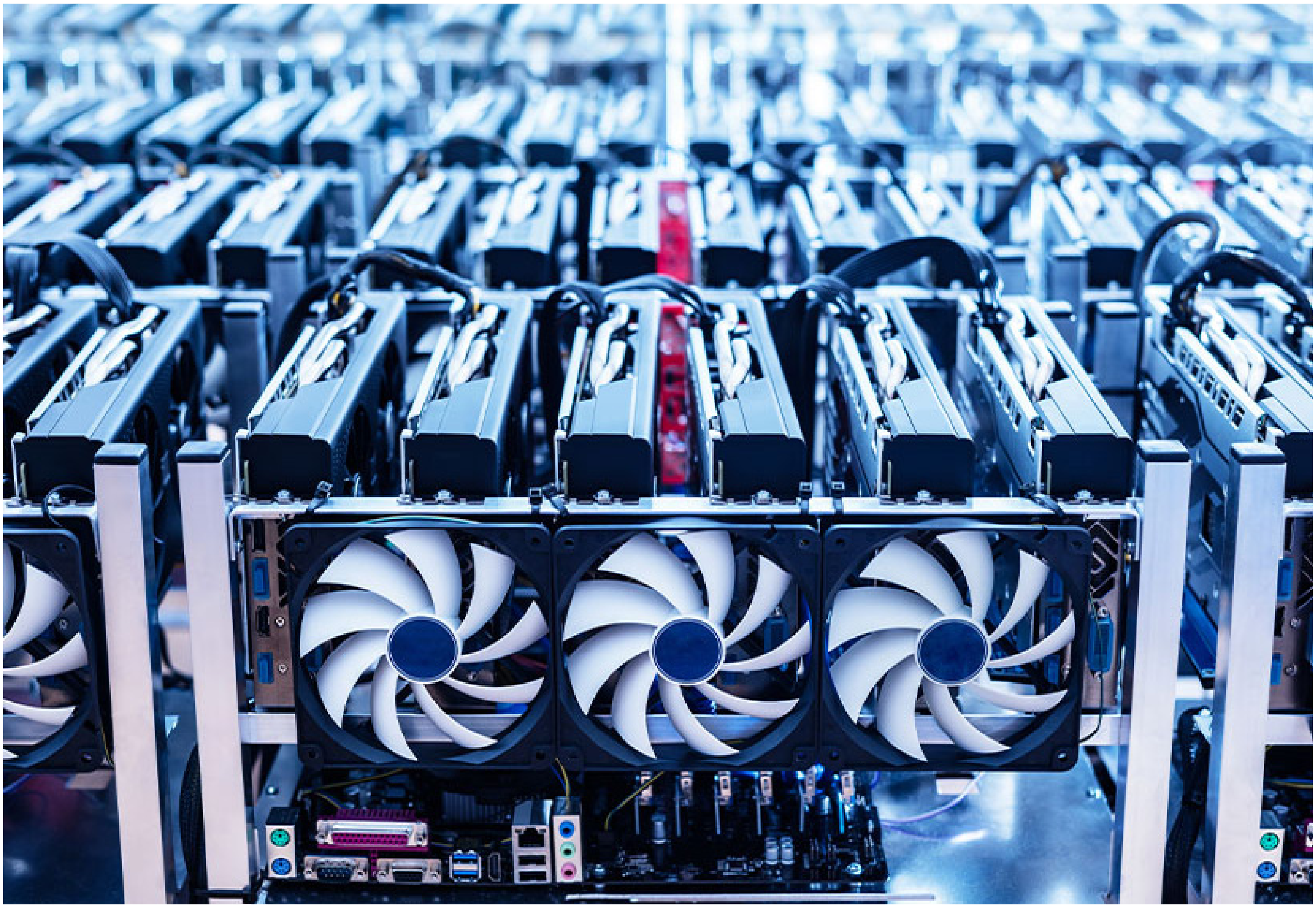
The project would entail NYISO investigating the rules that assign or reallocate the UCAP requirement such that if a large load departs a transmission district, the remaining customers are treated equally.

Why This Matters

NYPA submitted its proposal for a NYISO market project just before the ISO's deadline.

Generation developer JERA Americas also submitted a project *proposal* to increase transparency in market operations. Specifically, it wants more data regarding system topology, branch characteristics and branch flows. It also wants transmission line ratings and the causes of transmission line outages to be published. ■

— Vincent Gabrielle



| *Shutterstock*

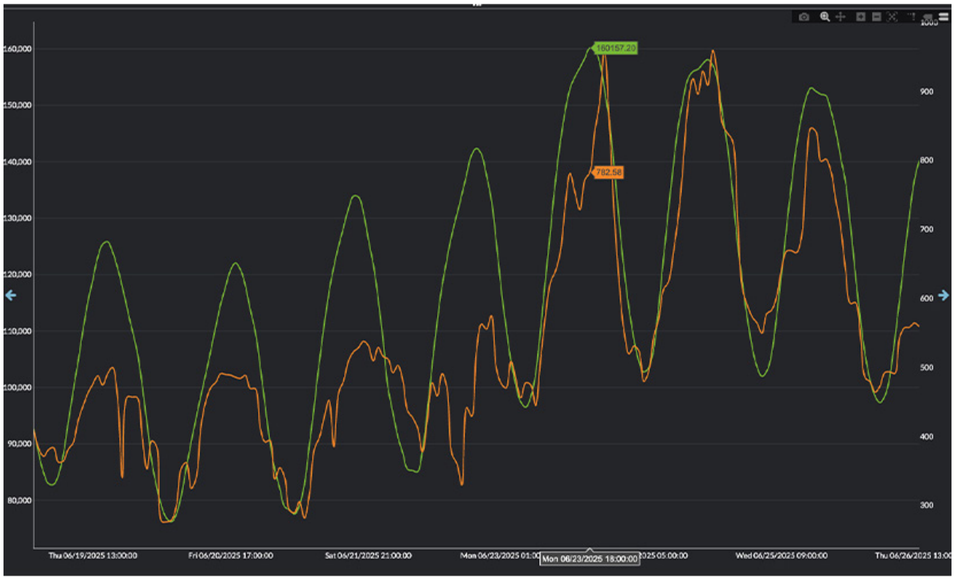
PJM Exceeds Forecast Summer Peak Load During June Heat Wave

By Devin Leith-Yessian

PJM experienced a preliminary peak load over 160 GW on the afternoon of June 23, surpassing the RTO's summer forecast of 154 GW and requiring the deployment of pre-emergency demand response. (See *PJM Summer Forecast Reports Sufficient Supply*.)

The heat wave blanketing much of the region brought temperatures of around 100 degrees Fahrenheit, leading to an RTO-wide hot weather *alert* being issued between June 22 and 25, which was *extended* to include the 26th as well. Several pre-emergency load management reduction actions were taken June 24 across the RTO, while DR also was called for the Mid-Atlantic and Dominion regions June 23 and 25.

Two maximum generation/load management alerts were issued on June 24 and 25, a notification instructing resource owners to be prepared to operate above their economic parameters if emergency actions are taken. The alerts also put PJM into NERC's Energy Emergency Alert (EEA) 1 status for their duration.



Yes Energy's Live Power data show the spike in usage during the heat wave. | *Yes Energy*

PJM spokesperson Daniel Lockwood said the June 23 and 24 peaks are the highest PJM has seen since 2011 and both place in the top five for all-time peak demand.

PJM also *reported* that it has dispatched Eddystone Units 3 and 4 throughout the heat wave. The generator is being operated past its requested deactivation date of May 31 under a Department of Energy emergency order expiring Aug. 28. Eddystone Unit 3 ran for 16 hours on June 23 and all day on the 24th, while Unit 4 operated 14 hours on the 23rd and 20 hours the following day. Both units ran all day on June 25. (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online*.) ■

PJM Board Selects Cost Allocation for Eddystone

By Devin Leith-Yessian

The PJM Board of Managers is pursuing an approach that would spread the cost of continuing to operate Constellation Energy's Eddystone Generating Station to all PJM consumers. (See *PJM Stakeholders Propose Cost Allocation Models for DOE Emergency Orders*.)

In a June 26 *letter* to stakeholders, Chair David Mills said the board selected a proposal sponsored by Gabel Associates through the Critical Issue Fast Path (CIFP) process initiated to determine how Constellation should be paid for keeping Eddystone online under a Department of Energy emergency order.

Mills noted that the package was the only one to receive a supermajority of sector-weighted support during a June 18 Members Committee (MC) meeting. The board has directed PJM staff to file the proposal at FERC by the end of June.

Gabel's proposal was set apart from five other packages sponsored by PJM and the East Kentucky Power Cooperative (EKPC) by its RTO-wide allocation and focus on the current DOE order. Some of the alternatives contemplated how PJM should proceed if more generators are ordered to remain online by the federal government. The cost allocation would expire Aug. 28 along with the conclusion of the emergency order.

The proposal would determine the charges for each entity by multiplying its share of the RTO monthly unforced capacity (UCAP) obligation by the monthly credit paid to Constellation. The costs to be included in that credit are subject to review by the Independent Market Monitor (IMM).

A new line item will be included on billing statements showing the cost of that credit, and PJM will post information on its website about the credits and guidance on how they are settled. The proposal carries a June 1 implementation date to capture costs Constellation may have incurred since the DOE order took effect.

During the MC meeting, Constellation Vice President of Wholesale Market Development Adrien Ford said the company did not vote for the proposal out of concern it would allow cost allocation to lapse if DOE issues subsequent orders to keep Eddystone operational.

PJM headquarters | © RTO Insider

Why This Matters

The PJM selection of a proposal to allocate the costs for Constellation Energy to keep the Eddystone Generating Station operating under a Department of Energy emergency order comes as many believe more orders likely will be issued to delay deactivations.

Some speakers encouraged the board to modify the Gabel proposal to apply to either additional orders on Eddystone or orders that may be announced in coming weeks.

Carl Johnson, representing the PJM Public Power Coalition, said some of the proposal's support came from a belief that more orders should be addressed as they arise.

Mills wrote that the board deliberated on modifying the proposal but opted against making any changes due to mixed feedback it received. He also noted that the Markets and Reliability Committee endorsed a PJM issue charge to consider a long-term cost allocation framework for deactivations delayed under the Federal Power Act (FPA) Section 202(c) orders.

"Recognizing there may be further DOE 202(c) orders related to generating units in the PJM region in the foreseeable future, the board is encouraged by the fact that the stakeholders have endorsed an *issue charge* to work on a cost allocation methodology for future DOE 202(c) orders that may require resources to remain operationally available beyond previously anticipated deactivation dates. PJM will announce the commencement of that stakeholder discussion in the near term," he wrote.

PJM *reported* that it has dispatched Eddystone during a heat wave affecting the PJM region on June 23, 24 and 25. Unit 3 ran for 16 hours on June 23 and all day on the 24th, while Unit 4 operated 14 hours on the 23rd and 20 hours the following day. Both units ran all day on June 25. ■

Constellation Moves Reactor Restart Target Forward to 2027

Strong Progress on Several Fronts Reported at Former Three Mile Island

By John Cropley

Constellation Energy said the former Three Mile Island could come back online as the Crane Clean Energy Center a year earlier than initially expected.

PJM approved an early interconnection request, hiring and training are going well, and significant progress has been made on major equipment purchases, the company said June 25 during a celebratory event at the southeast Pennsylvania facility.

When Constellation *went public with its plans* in September 2024, it targeted a 2028 restart. (See *Constellation to Reopen, Rename Three Mile Island Unit 1*.)

The company now says the facility could come online as soon as 2027.

Crane is roughly two-thirds staffed, with nearly 400 full-time employees hired and 58 more scheduled to start soon. Technical milestones include the successful inspection of the main generator and turbines and other major systems. The new main power transformers are scheduled to be delivered in 2026.

Importantly, the facility was among those fast-tracked in May through PJM's Reliability Resource Initiative. (See *PJM Selects 51 Projects for Expedited Interconnection Studies*.)

Constellation CEO Joe Dominguez spoke of the confluence of factors working in favor of the project: PJM's actions; financial support from Microsoft, which will buy 835 MW of output for its data centers; community backing; and support from Pennsylvania Gov. Josh Shapiro (D), who also spoke at the ceremony.

Why This Matters

Constellation is reporting faster-than-expected progress in bringing its retired reactor back online, a feat never accomplished in the United States.

Officials and guests gather June 25 at the Crane Clean Energy Center to mark Constellation Energy's progress preparing to restart the former Three Mile Island Unit 1. | *Constellation Energy*

PJM President Manu Asthana told the crowd about the project's importance to the region, the nation and the grid, which is wrestling with resource adequacy.

"I'm here to say 'thank you' for that," he said. "PJM understands the importance of bringing this project and other projects like it online quickly, and our engineers are back in the office, working as hard as possible to accelerate that."

The heat wave did not pause for the ceremony: The temperatures climbed into the 90s under the blazing sun at the Crane Clean Energy Center, and public demand for electricity rose with the heat.

Asthana said two days earlier, the PJM control room observed an all-time high peak, 9 GW higher than last summer's peak.

"Now let me put that in context," he said. "That is 11 Crane Clean Energy Centers from last year's peak to this year's peak. What we're talking about here is not hypothetical. Our country needs this power."

Dominguez marveled at the turn of history at one of the best-known nuclear facilities in the world.

"Boy, what an incredible, incredible moment," he said. "The comeback of this plant, the comeback of the industry. It's just kind of amazing."

The partial meltdown of Three Mile Island Unit 2 in 1979 energized popular opposition to commercial nuclear power. Unit 1 was undamaged and came back online several years later, but Constellation's corporate predecessor, Exelon, *shut it down* in September 2019 due to uneconomical market and policy conditions. Other reactors nationwide were retired for the same reasons.

Just a few years later, nuclear power is poised for a renaissance, with politicians and industry willing to help subsidize nuclear generation in return for its steady, emissions-free output. Plenty of critics remain, but even some former opponents of nuclear power now offer support.

Unit 1 is among the oldest reactors in the aging U.S. fleet, *first licensed in 1974*. But the anticipated $1.6 billion cost of the restart project would be a small fraction of the cost of building a comparable facility.

The easiest step forward into Three Mile Island's next chapter also was the most literal: Constellation renamed it after the late Chris Crane, Exelon's CEO from 2012 to 2022.

The Nuclear Regulatory Commission approved the change in May. ■

Duke Energy Carolinas Authorized to Maximize Generation Amid Heat Wave

DOE 202(c) Emergency Order Affects Selected Power Facilities as Temperatures Threaten Reliability

By John Cropley

The U.S. Department of Energy has issued an emergency order authorizing Duke Energy Carolinas to operate certain generation facilities at maximum output to meet heat-related demand.

It was the fourth invocation in six weeks of the lightly used Section 202(c) of the Federal Power Act, and it was the first time in nearly two years that high heat prompted such an order.

Duke requested the order June 23 as humidity and temperatures approaching 100 degrees Fahrenheit were settling over its service area in North and South Carolina. It said it expected a small percentage of its generating units to experience operating difficulties due to the heat and said also that 1,500 MW of capacity is offline or derated.

Meanwhile, with a heat index in the low 100s, the utility forecast 21,968 MW of load for Duke Energy Carolinas.

Duke declared an Energy Emergency Alert Level 2 (EEA 2) and told DOE it might not be able to meet the demand and might need to curtail load to preserve grid reliability.

Early June 24, Energy Secretary Chris Wright signed *Order No. 202-25-5*. It expires at 10 p.m. June 25, but Duke can request a renewal.

At 3 p.m. June 24, the National Weather Service reported a temperature of 98 degrees and a heat index of 105 in Duke's hometown, Charlotte, N.C. It predicted a heat index as high as 110 on June 25 and forecast high temperatures would reach the low to mid 90s over the following few days.

Why This Matters

The emergency authorization may be needed to prevent load curtailment in Duke's territory in the Carolinas.

Also at 3 p.m., Duke's outage map showed 121 outages totaling just 816 customers without power in the Carolinas. And the U.S. Energy Information Administration's hourly electric grid monitor was showing Duke Energy Carolinas at 21,306 MW of demand.

Duke Energy spokesperson Jennifer Garber told *RTO Insider*: "The grid is performing as expected and we currently have adequate power generation to meet our customers' needs."

The 202(c) order would be used only if needed to preserve reliability, she said, and is narrowly focused on a few facilities: Duke's Buck Station, Lincoln Combustion Turbine Station, Marshall Steam Plant and Rockingham Station, plus a few units that independent power producers requested be included.

The request to DOE was a precautionary step as part of Duke's all-of-the-above preparation for the heat wave, Garber said.

The utility *issued conservation appeals* for customers in the Carolinas to reduce their energy use, particularly during the peak 3-8 p.m. period.

The DOE order noted Duke had also curtailed all recallable energy sales and implemented its load management program, including residential demand response and large-load curtailments. Duke also notified wholesale customers to implement in-kind load management programs. These efforts were expected to shave 700 to 1,000 MW off peak demand.

Meanwhile, the order said, Duke obtained as much external capacity as it could — approximately 1,332 MW.

Duke told DOE it would exhaust these options before it ran any generation units in a manner that would conflict with local, state or federal regulations and permits.

The 202(c) order authorizes the generators to operate at maximum capacity only as needed and only as long as Duke has declared an EEA 2 or EEA 3.

Duke Energy's Lincoln Combustion Turbine Station | *Duke Energy*

Rare Invocation

Section 202(c) has been used infrequently. *On its website*, DOE lists just 26 such orders in the past quarter-century. Many of the recent orders were related to extreme weather — heat, hurricanes and the infamous Winter Storm Uri, which hit ERCOT in 2021.

In the past year, there have been six orders:

- Oct. 9, 2024, authorizing Duke Energy to operate certain generating units at low load due to the effects of Hurricane Milton;
- May 16, 2025, two orders to the Puerto Rico Electric Power Authority to expand baseload generation and manage vegetation that threatens transmission facilities;
- May 23, 2025, blocking the retirement of Consumers Energy's J.H. Campbell Plant in Michigan to preserve capacity in MISO (See *DOE Orders Michigan Coal Plant to Reverse Retirement*);
- May 30, 2025, blocking retirement of two units at Constellation's Eddystone Generating Station in Pennsylvania to preserve capacity in PJM (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online*); and
- June 24, 2025, to help Duke deal with the heat wave.

Before that, the most recent heat-related 202(c) order authorizing maximum generation output was issued to ERCOT on Sept. 7, 2023, as temperatures in Dallas hit a record 107 degrees. ■

FERC Partly Accepts SPP's Order 2023 Compliance

By Tom Kleckner

FERC has accepted SPP's compliance with Orders Nos. 2023 and 2023-A in part and directed the RTO to submit a further filing within 60 days of the order (*ER24-2026*).

The commission said in its June 26 order that SPP's proposed tariff revisions amending the commission's *pro forma* generator interconnection procedures and *pro forma* generator interconnection (GI) agreements partly comply with the orders.

It found that the RTO's proposal to post the interconnection studies from the close of its definitive interconnection system impact study (DISIS) cluster to the date when the transmission provider provided the completed study, as opposed to from the close of the cluster request window, deviated from the *pro forma* GI procedures. FERC said SPP's standard "does not explain how the proposed variation accomplishes the purposes of Order 2023."

The commission also found SPP's revisions did not incorporate a reference to the "surplus interconnection service study" contained in the *pro forma* large generator interconnection procedures (LGIP) and that the definition of "scoping meeting" in its GI procedures didn't incorporate the commission's revisions to the definition. It said the proposal does not incorporate FERC's removal of the phrase "to determine the potential feasible points of interconnection" and that its *pro forma* GIA does not include the defined term "cluster."

When SPP made its compliance filing May 24, it said it had made several reforms following Order 2023's issuance, including a three-stage interconnection study process with increasing financial milestones at each stage. It also proposed replacing "cluster study" and "cluster restudy" with "DISIS" and "DISIS restudy."

FERC had several issues with SPP's proposed language on site control. It said the grid operator did not explain the omission of timing requirements when it would notify interconnection customers of a required restudy; it did not fully incorporate the commission's revisions to the *pro forma* definition of "site control"; it did not request an independent entity variation for its proposal to retain its existing GI procedures provisions requiring 100% site control at the time of an interconnection request; and it did not address FERC's requirement for transmission providers to include a narrative description of how they will define regulatory limit.

The commission ordered SPP to address:

- How the following two items meet the purposes of Orders 2023 and 2023-A. Not adopting the commission's requirement that the transmission provider treat the GIA deposit as part of the security that the interconnection customer must provide for network upgrades and interconnection facilities; and not requiring the transmission provider to explain and estimate the dates at which an interconnection customer must provide additional security for interconnection facilities and network upgrades when the GIA deposit is depleted.
- How it will incorporate the requirement that the transmission provider perform affected system restudies within 60 calendar days from the date of notice.

FERC directed the grid operator to:

- Remove certain language regarding the submission of multiple interconnection requests and deposits or further justify its proposal under the independent entity variation standard.
- Revise the GI procedure language to specify which enumerated alternative transmission technologies evaluation results are reported in the first two DISIS studies and to clarify when interconnection customers will receive the evaluation results of the alternative transmission technologies.
- Reinstate language regarding transitional notice requirements for generating facility replacement in a future Section 205 filing under the Federal Power Act.

SPP's filing drew 22 intervenors and protests by the Clean Energy Association, Longroad Energy Holdings and Shell. FERC rejected the majority of the complaints.

FERC issued *Order 2023* in July 2023, seeking to clear backlogged interconnection queues by implementing a first-ready, first-served cluster study process; increasing interconnection customers' financial obligations; and penalizing grid operators for missing study deadlines. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

In 2024, the commission rejected challenges to the interconnection rules under Order 2023 and made several clarifications, minor modifications and an extended compliance deadline with *Order 2023-A*. (See *FERC Upholds, Clarifies Generator Interconnection Rule*.) ■

FERC has partially approved SPP's compliance with Orders 2023 and 2023-A. | *Grid United*

SPP Launches Markets+ Phase 2 with $150M Secured

Training for Markets+ Participants Already Underway

By Henrik Nilsson

SPP has secured $150 million in financing and entered the second phase of development for its day-ahead market Markets+, the grid operator announced June 30.

Arkansas-based Simmons Bank provided the loan, which is collateralized by eight Markets+ funders, allowing SPP to begin developing "critical systems, processes and operations required to conduct market trials," according to the announcement.

"Securing financing for phase two of Markets+ is a pivotal step forward," Carrie Simpson, vice president of markets at SPP, said in a statement. "It allows SPP to continue developing a more efficient, transparent and reliable energy market for our western stakeholders and their customers."

With the announcement, SPP has now entered the second phase of market development. The grid operator has already started its requirement planning and Markets+ training for stakeholders. Stakeholder onboarding processes, including network and commercial modeling, are scheduled to begin Aug. 1, 2025, while connectivity and data exchange testing is slated for late 2026. SPP plans to launch Markets+ on Oct. 1, 2027, according to a timeline posted on SPP's website.

In April, FERC approved the SPP Phase 2 funding agreement, which details how SPP will finance Markets+'s $150 million in implementation costs. (See *FERC Approves SPP's Funding Plans for Markets+*.)

According to the June 30 news release, the eight Western entities that have signed the agreement include Arizona Public Service, Bonneville Power Administration, Chelan County Public Utility District (PUD), City of Tacoma, Grant County PUD, Powerex, Salt River Project and Tucson Electric Power. (See *SPP Secures Funding to Begin Markets+ Phase 2*.)

Why This Matters

With $150 million secured, SPP can now begin development of crucial processes and begin training Markets+ participants.

SPP said it has secured financing to begin the second phase of developing Markets+. | *SPP*

The agreement requires the entities to provide collateral to SPP's lender to support the financing the RTO will use to develop Markets+ during the implementation phase. The collateral is equal to the amount of the entities' Phase 2 obligations.

The recovery of the costs to repay the implementation financing "will be incorporated into the rates charged in the Markets+," according to a frequently asked questions document posted on SPP's website.

BPA, which committed to Markets+ in May, is one of the largest funders of SPP's day-ahead market endeavor. (*See BPA Chooses Markets+ over EDAM* and *BPA Markets+ Phase 2 Bill Could Reach $27M — or More*.)

Agency spokesperson Nick Quinata told *RTO Insider* that BPA's commitment for Phase 2 will not exceed $36 million based on the current number of funding parties.

"If additional parties join Phase 2, that would reduce BPA's share of Phase 2 development costs and, thus, total liability," Quinata said. "All entities participating in Phase 2 will have these costs recovered through transactional fees once they begin market participation."

Meanwhile, Grant PUD spokesperson Christine Pratt said the utility acquired a letter of credit for approximately $4.2 million to contribute to Phase 2. The credit will assist with "the upfront expenses needed for market startup. This includes computer systems — hardware and software — and personnel."

Grant PUD noted that it did not have to contribute any funds for Phase 2 but was required to provide a letter of credit in case the market failed. Under that scenario, the credit will be called for the amount needed by SPP to recover any costs incurred in standing up the market.

"We're preparing for Markets+ trading by evaluating our own needs for personnel and equipment," Pratt said. "Our basic interests or priorities are for the market to succeed. These priorities will likely become more specific as collaboration continues, but for now, a successful market is the goal."

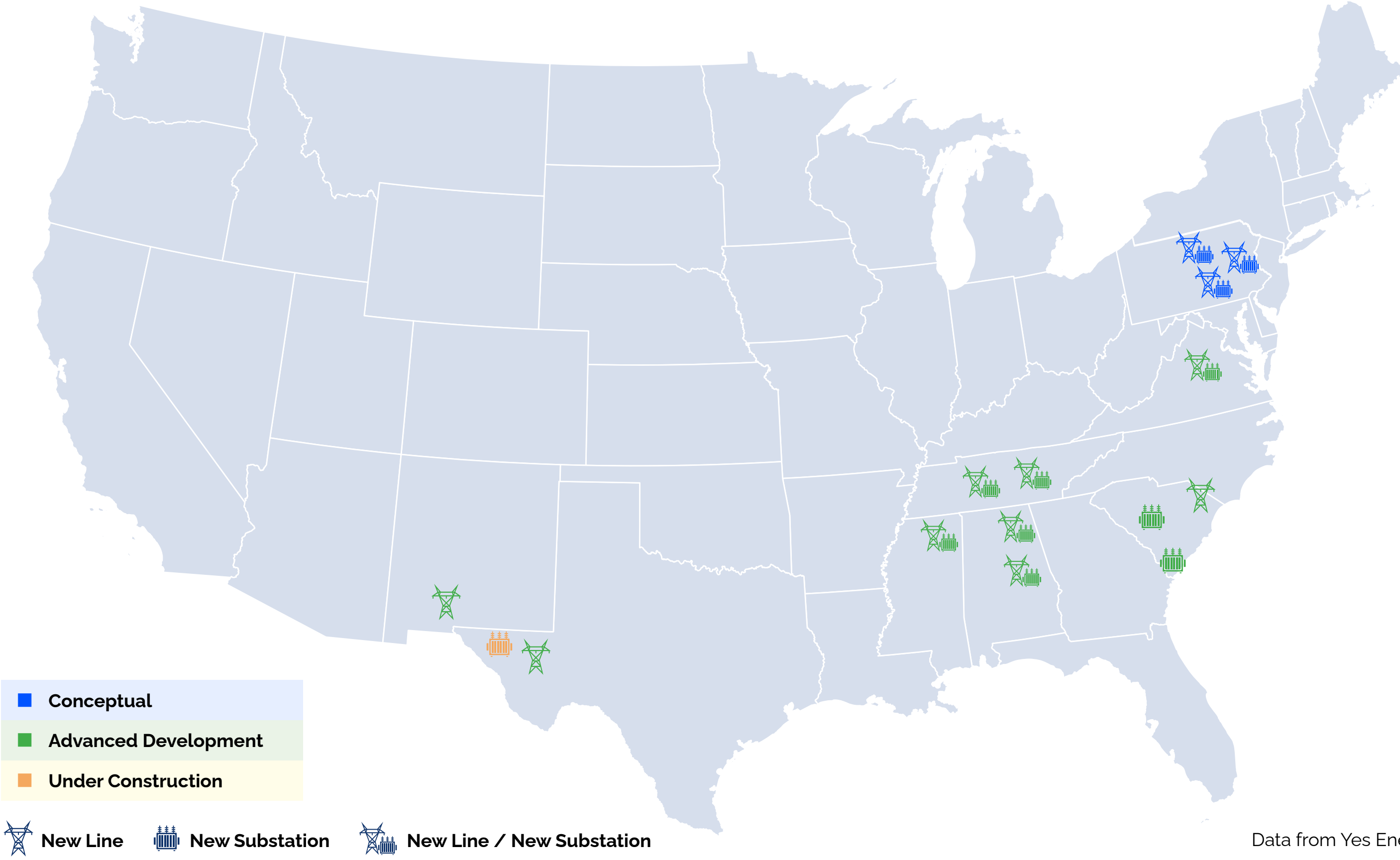
Chelan PUD spokesperson Rachel Hansen said the utility contributed approximately $820,000 in collateral.

"Moving forward, Chelan PUD will focus on preparing for market readiness and has not chosen its go-live target date," Hansen said.

SPP said in the news release that stakeholders are signing additional Phase 2 funding and participation agreements "based on their entities' respective sector and role in the market." ■

T&D Projects Added in the Past Week

YES ENERGY



Data from Yes Energy

Project Name	Holding Company or Parent Organization	Utility	Voltage (kV)	In Service Year	Endpoint 1 / 2	Reported Cost/Budget
Star Gap New Station and Line	Tennessee Valley Authority	Tennessee Valley Authority	161	2028	AL / AL	
New Liberty - Centre - Piedmont Transmission Line	Tennessee Valley Authority	Tennessee Valley Authority	161	2027	AL / AL	
RailHub - South New Substation and Line (Alcorn County)	Tennessee Valley Authority	Tennessee Valley Authority	161	2028	MS / MS	
Airport - Vado 345 kV New Line	Infrastructure Investments Fund	El Paso Electric	345	2029	NM / NM	
Orefield New Substation	PPL Corp.	PPL Corp.	500	2028	PA / PA	$159,000,000
Tomhicken Substation Upgrade	PPL Corp.	PPL Corp.	230	2027	PA / PA	$13,500,000
Lackawanna - Callender Gap #2 New Line	PPL Corp.	PPL Corp.	230	2028	PA / PA	$73,500,000
Winnsboro West New Substation	Dominion Energy	Dominion Energy South Carolina	230	2028	SC	
Deerfield New Switching Station (Okatie - McIntosh)	Dominion Energy	Dominion Energy South Carolina	115	2028	SC	
Marion - Red Bluff New Line	Santee Cooper	Santee Cooper	230	2028	SC /SC	
Fall Creek New Substation and Line	Tennessee Valley Authority	Tennessee Valley Authority	161	2027	TN / TN	
109 North New Station and Line	Tennessee Valley Authority	Tennessee Valley Authority	161	2027	TN / TN	
Wicked New Switching Station	Infrastructure Investments Fund	El Paso Electric	115	2025	TX	
Marvin - Seabeck 115 kV New Line	Infrastructure Investments Fund	El Paso Electric	115	2027	TX / TX	
Reed Farm (South Fork) New Substation	Dominion Energy	Dominion Virginia Power	230	2026	VA / VA	$19,000,000

Company Briefs

Ormat Acquires Blue Mountain Geothermal Plant

Geothermal project developer Ormat Technologies has acquired the 20-MW Blue Mountain power plant from Cyrq Energy.

The $88 million transaction gives Ormat 100% equity interest in the Nevada plant and increases its geothermal portfolio to nearly 200 power plants totaling more than 1,200 MW.

The plant currently delivers power under a power purchase agreement with NV Energy. The deal is scheduled to expire at the end of 2029, although Ormat intends to up the capacity by 3.5 MW.

More: *EnergyTech*

Cheniere Energy Launches $2.9B Corpus Christi LNG Expansion

Cheniere Energy, the country's largest exporter of liquefied natural gas, last week approved an expansion project worth $2.9 billion at its Corpus Christi facility.

The company contracted engineering and construction giant Bechtel Energy to begin construction on two additional trains. The addition is expected to increase LNG production by 3 million metric tons a year.

More: *Houston Chronicle*

Meta Signs EAPAs with Adapture for Texas Solar Power

Meta last week announced it has signed two Environmental Attributes Purchase Agreements (EAPAs) with Adapture Renewables for 360 MW from two solar projects in Texas.

The deal will see Adapture supply the power to the ERCOT grid, with Meta purchasing the environmental attributes of the project's renewable energy generation via renewable energy credits.

The projects are both expected to reach commercial operation in 2027.

More: *Data Center Dynamics*

Federal Briefs

Global Energy CO2 Emissions Reached Record High in 2024

Global carbon dioxide emissions from the energy sector hit a record high for the fourth year running in 2024, according to the Energy Institute's annual statistical review of world energy.

The world saw a 2% rise in total energy supply in 2024, with all sources of energy registering increases for the first time since 2006, the report said. This led to carbon emissions increasing by around 1% and exceeding the record level set the previous year at 40.8 gigatons of carbon dioxide equivalent.

More: *Reuters*

BLM Approves Natural Gas Pipeline, 3 Geothermal Projects

The Bureau of Land Management last week approved a 74-mile natural gas pipeline in Montana and three geothermal energy projects in Nevada.

NorthWestern Energy's proposal for the pipeline was approved by BLM in response to President Donald Trump's national energy emergency. The route will be on about nine miles of public lands managed by BLM. Construction will be done in phases between spring 2026 to fall 2029.

The three geothermal projects will be the Diamond Flat Geothermal Project, the McGinness Hills Geothermal Optimization Project and the Pinto Geothermal Project.

More: *NBC Montana*; *BLM.gov*

State Briefs

ARIZONA

Coronado Generating Station to be Converted to Natural Gas

The Salt River Project Board last week approved the plan to convert the Coronado Generating Station from coal to natural gas.

SRP said switching the facility to gas is the lowest-cost option to preserve the plant's generating capacity while also working toward carbon-reduction goals. The utility has plans to phase out coal generation across its sites and achieve net-zero carbon emissions by 2050.

SRP expects the project to be complete by 2029.

More: *KJZZ*

Tucson City Council: No November Election for TEP Franchise Deal

The Tucson City Council last week voted to delay a potential special election this November for voters to decide on a new franchise agreement between the city and Tucson Electric Power, saying the two parties had failed to come to an understanding in time to meet a July 1 deadline.

The mayor and council opted to hold off on a potential election until next spring, before the current franchise agreement expires in April 2026.

The franchise agreement allows TEP to use city property to install power lines and other infrastructure without needing to ask for a permit each time, in exchange for a fee paid to the city. The agreements typically last around 25 years, though voters rejected a previous attempt at renewing the franchise terms in 2023.

More: *Tucson Sentinel*

COLORADO

Elbert County Denies Xcel Energy's Power Pathway Permit Request

Elbert County commissioners last week voted 3-0 to deny project permits for Xcel Energy's $1.7 billion Colorado Power Pathway transmission project.

The 550-mile project is set to run through the heart of Elbert County. Xcel needs rights of way through 48 properties in the county, but only 25 landowners have agreed. The utility has begun eminent domain proceedings on 13 properties.

More: *The Colorado Sun*

LOUISIANA

AG Looking into Tren Solar After Complaints

The Attorney General's office last week confirmed it is looking into complaints against solar company Tren Solar.

The company suddenly closed last month, leaving customers with expensive, non-working solar systems.

Public records show Tren Solar was barred from doing work in Arkansas before shutting down. The state's Residential Contractors Committee fined Tren Solar and banned it from operating in the state in November 2023. Tren Solar did not attend the hearing.

More: *WVUE*

MISSOURI

Ameren Unveils Plans for Big Hollow Energy Center

Ameren last week filed an application with the Public Service Commission that includes the construction of an 800-MW simple-cycle natural gas energy center and a 400-MW battery storage facility in Jefferson County known as the Big Hollow Energy Center.

Pending regulatory approval, the center is expected to be operational in 2028.

More: *Ameren*

NEVADA

PUC Approves Investigation into NV Energy for Overcharging

The Public Utilities Commission last week unanimously approved an investigation into NV Energy for overcharging "tens of thousands" of customers.

The investigation into the utility will look to identify "the full extent of misclassifications of customers and how such misclassifications occurred, whether NV Energy misapplied its tariffs, and appropriate remedies to avoid future misclassifications and compensate overcharged customers."

In May, regulatory operations staff filed a petition to open an investigation into NV Energy after it was revealed it overcharged 60,000 "misclassified residential customers" over $17 million between April 1, 2017, and April 1, 2024.

More: *Las Vegas Review-Journal*

NEW YORK

Chautauqua, Mayville Place Moratoriums on Wind, Storage

The town of Chautauqua and village of Mayville are updating their Comprehensive Plan and have placed moratoriums on wind energy and storage systems, respectively, until the plan is in place.

Mayville leaders passed a one-year moratorium on new battery energy storage systems, while the Chautauqua Town Board approved a one-year moratorium on wind energy systems.

More: *The Post-Journal*

Utilities Must Reimburse Customers for Storm-related Outages

The Appellate Division's Third Department last week issued a ruling upholding a 2022 state law requiring utilities to reimburse customers for long storm-related outages.

All the state's major utilities had joined the lawsuit, which sought to overturn the law. The law also bars utilities from later recovering the storm costs from its ratepayers. It requires customers receive a $25 bill credit for each 24-hour period of an outage that lasts longer than 72 hours.

The law was passed after several winter storms and Tropical Storm Isaias in 2020 left 900,000 customers without service.

More: *Times Union*

VIRGINIA

Latest Lawsuit Fails to Stop Botetourt County Wind Farm

The Virginia Court of Appeals last week unanimously blocked a lawsuit that sought to stop construction of a Botetourt County wind farm.

The panel found the opponents lacked standing to legally object to a temporary facility that will produce concrete needed for the foundations of the massive turbines.

Apex Clean Energy plans to build 13 turbines on top of a mountain northeast of Eagle Rock. It will be the state's first onshore utility-scale wind farm. When completed, it will produce up to 78 MW for Google.

More: *The Roanoke Times*

WISCONSIN

Legislation to Expand Nuclear Power Heads to Gov. Evers' Desk

The state Assembly last week passed a set of bills that would expand nuclear power in the state, sending the plans to Gov. **Tony Evers**' desk.

One of the bills would establish a board to host a summit in Madison to transform the state into an industry leader. Another would mandate a study into where more nuclear plants could be established.

Lawmakers also approved a bipartisan joint resolution affirming a legislative commitment to expanding nuclear power. The resolution calls nuclear and fusion energy "clean energy sources that are critical to safely meeting Wisconsin's growing energy demands."

More: *Wisconsin Public Radio*