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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

DOE Cuts NIETC List from 10 to 3 High-priority Transmission Corridors

By K Kaufmann and Tom Kleckner

The U.S. Department of Energy has slashed the list of 10 potential National Interest Electric Transmission Corridors it released in May to just three much narrower corridors in the third phase of its designation process, the department announced Dec. 16.

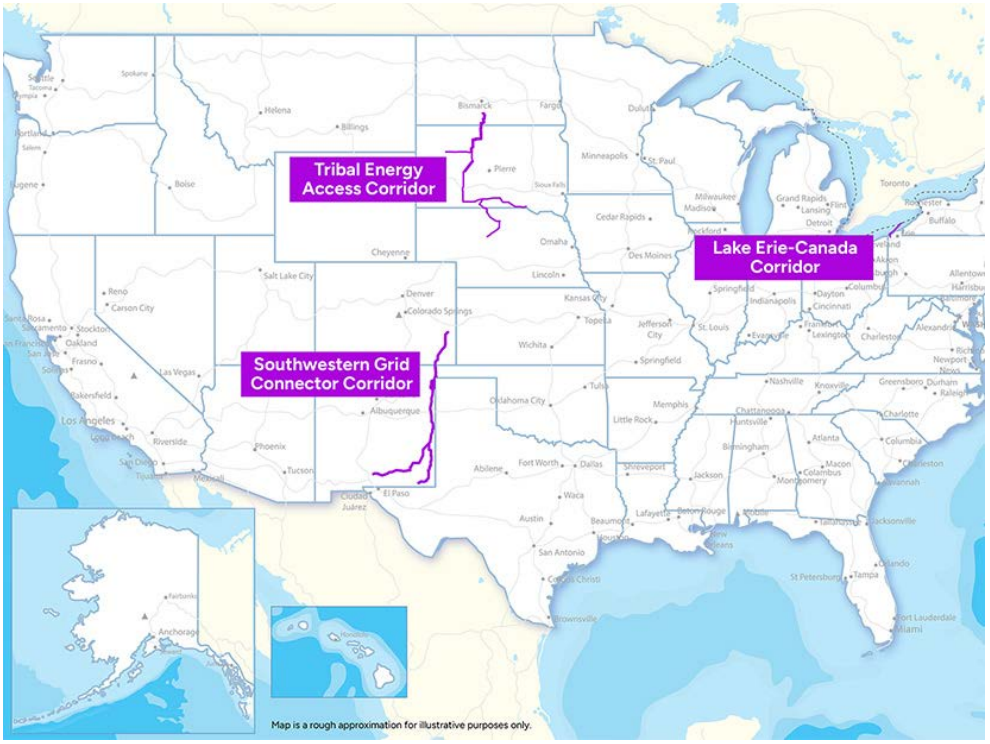
Established under the Federal Power Act, NIETCs are geographically defined areas in which the secretary of energy finds "present or expected transmission capacity constraints or congestion that adversely affects consumers," according to the *announcement* published in the *Federal Register*. Transmission projects located within a NIETC are eligible for special DOE financing and FERC permitting processes aimed at accelerating development and construction.

DOE set out a four-step process for NIETC designations in December 2023, including an initial information-gathering phase to help identify potential NIETCs, followed by the release of the preliminary list of 10 possible corridors in May. (See *On the Road to NIETCs, DOE Releases Preliminary List of 10 Tx Corridors*.)

The three proposed NIETCs selected in Phase 3 are:

- the Lake Erie-Canada Corridor, including parts of Lake Erie and Pennsylvania;
- the Southwestern Grid Connector Corridor, including parts of Colorado, New Mexico and a small portion of western Oklahoma; and
- the Tribal Energy Access Corridor, including central parts of North Dakota, South Dakota, Nebraska and five tribal reservations.

According to *DOE*, its decisions on these three corridors were based on its own analysis and the public comments it received during the first two phases of the process, as well as priorities set in the department's *National Transmission Needs Study* released in October 2023.



Potential National Interest Electric Transmission Corridors | *DOE*

"Transmission development in these areas is critical to address transmission needs … unmet through existing planning processes," DOE said. All three corridors also have one or more transmission projects under development, which DOE sees having near-term impacts on easing grid congestion, helping to put more renewable energy online and cutting consumer costs.

For example, the Lake Erie-Canada Corridor is a slimmed-down version of the Mid-Atlantic-Canada corridor on the Phase 2 list of 10 potential NIETCs. The Phase 3 version contains a smaller area in Pennsylvania and a larger area in Lake Erie. NextEra Energy Transmission's *Lake Erie Connector* project, a 73-mile underwater line, could be located in the corridor, allowing for bidirectional energy flows between Pennsylvania and Ontario.

While the project is still in the early phases of development, a transmission corridor with that kind of HVDC line would increase capacity for clean energy integration on the grid, as well as support resource adequacy in PJM via the connection with Canada, according to DOE.

The Tribal Access Corridor is a similarly "refined" version of DOE's Phase 2 Northern Plains potential NIETC, with most of the corridor running along existing rights of ways and connecting several tribal reservations to existing or planned HVDCs.

The corridor includes parts of the Dakotas, Nebraska, the Cheyenne River Reservation, Pine Ridge Reservation, Rosebud Indian Reservation, Standing Rock Reservation and Yankton Reservation.

NIETC designation here could help the Transmission and Renewables Interstate Bulk Electric Supply (TRIBES) HVDC project being developed by the Western Area Power Administration and other tribal and regional stakeholders, as well as relieving congestion and preparing for future demand growth. Nebraska, for example, is becoming a hub for data center development as part of a new "Silicon Prairie."

While highlighting these projects, DOE noted that "NIETC designation is not a route determination for any particular transmission project, nor is it an endorsement of one or more transmission solutions."

Why These, not Those?

Declining to comment on specific corridors, Dylan Reed, senior adviser for external affairs

What's Next

A DOE spokesperson declined to comment on when final NIETC designations might be made. It is opening a 60-day comment period that will include three webinars.

FERC/Federal News

in DOE's Grid Deployment Office, listed a number of reasons for the others' exclusion.

"NIETC designation can disrupt effective transmission planning or ongoing transmission project development in the region. That was one consideration," Reed told *RTO Insider*.

"[No. 2] ... there appeared to be limited [ability for] a NIETC designation to further transmission in the near term in that area. In some cases, we lacked sufficient information to be able to narrow the boundaries to facilitate timely designation," he said.

Beyond prioritizing NIETCs that might meet shorter-term needs, DOE pointed to its own limitations of staffing and time for taking Phase 3 NIETCs to a final designation in Phase 4. The department is opening a 60-day comment period, which will include *three webinars*, one on each of the proposed NIETCs. The comment period will close Feb. 14, 2025.

Another key component of Phase 3 is determining whether the potential corridors will need a full environmental review under the National Environmental Policy Act. A NEPA review for each corridor could be required if DOE determines that "NIETC designation is a major federal action significantly affecting the quality of the human environment," according to the announcement.

The department is also asking for additional input on other meetings or community engagement activities it should plan as part of its environmental reviews.

A full NEPA review could take two years, so Reed would not speculate on when final NIETC designations might be made. He also declined to speculate on what impacts, if any, the incoming administration of President-elect Donald Trump might have on the NIETC process.

But DOE said its decision not to move the other Phase 2 projects forward does not mean those areas do not have transmission needs. "Rather, DOE is exercising its discretion to focus on other potential NIETCs at this time and may in the future revisit these or other areas through the opening of a new designation process," it said.

NIETC vs. NIMBY

Even before it was cut from the list, the Delta-Plains corridor drew strong political and public opposition within Oklahoma over the possibility of eminent domain acquisition of private lands.

As originally proposed, the corridor would have stretched 645 miles from Little Rock, Ark., through the Oklahoma Panhandle, with an 18-mile right of way in some portions.

"I won't let anyone steamroll Oklahomans or their private property rights," Gov. Kevin Stitt (R) *posted* on X. "The feds don't get to just come here and claim eminent domain for a green energy project that nobody wants."

Attorney General Gentner Drummond (R) sent a letter to U.S. Energy Secretary Jennifer Granholm calling the corridor "classic federal overreach" and pledged to protect private property rights.

DOE gave Oklahoma's leadership advance notice on Dec. 13 that the Delta-Plains corridor would not be moving forward.

With or without a NIETC, the region does not lack for proposed transmission projects that could run into similar NIMBYism. The Southwestern Grid Connector corridor will graze the western edge of Oklahoma's state line. DOE notes two projects in development in the potential NIETC: the Heartland Spirit Connector project by NextEra Energy Transmission, and the Southline Phase 3 project by Grid United.

Invenergy also has proposed the Cimarron Link to unlock access to the Oklahoma Panhandle's "inexhaustible wind energy."

SPP, which operates the grid in Oklahoma, has approved several large projects in the state as part of its 2024 Integrated Transmission Planning assessment. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.) ■

COMPANY ANNOUNCEMENT

RioSol
CLEAN ENERGY TRANSMISSION

RioSol Capacity Allocation

On January 6, 2025, El Rio Sol Transmission, LLC ("RioSol") will commence an open solicitation process to award up to 1,600 MW of bi-directional, point-to-point, firm transmission capacity. RioSol is holding this open solicitation process pursuant to its FERC authorization issued in Docket No. ER24-1726-000, dated July 5, 2024.

The RioSol Transmission Project consists of a proposed single-circuit, 500 kV alternating current electric transmission line and several substations that will transport energy from Arizona and New Mexico to customers and markets across the Desert Southwest. RioSol is seeking parties that can meet our criteria and work with us to enable the transmission project to commence construction by the end of 2026 and commence operating by the end of 2028. More information about the project can be found at www.riosol.energy.

RioSol has engaged Energy Strategies to manage the open solicitation process. Specific information about the forthcoming open solicitation process and timing can be found at www.riosol-os.com. On 12/18/2024, RioSol will host a webinar to review the project and Open Solicitation process and to answer questions from prospective customers. To sign up for the webinar, email RioSol-OS@energystrat.com.

Starting on January 6, 2025, interested entities may obtain a request for participation form and a confidentiality agreement via www.riosol-os.com and submit them to RioSol-OS@energystrat.com. Subsequently, interested entities deemed to have a legitimate interest in obtaining transmission capacity on RioSol will be provided with a confidential information memorandum and the expression of interest form. Completed expression of interest forms will be due no later than February 7, 2025.

FERC/Federal News

FERC Seeks Nearly $1B in Penalties from EE Provider in MISO, PJM

Enforcement Staff Finds American Efficient Operated 'Manipulative Scheme' in Capacity Markets

By Devin Leith-Yessian

FERC has ordered American Efficient to defend its energy efficiency programs in PJM and MISO or pay a $722 million penalty and return $253 million in profits to ratepayers.

The commission's Dec. 16 show-cause order directed the company demonstrate how it did not violate the Federal Power Act, FERC's anti-manipulation rule and the MISO and PJM tariffs "through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use" (*IN24-2*). (See "American Efficient Pushes Back on Allegations of Tariff Violations," *PJM Asks FERC to Eliminate Energy Efficiency from Capacity Market*.)

The commission said the company has 30 days to either elect for a hearing before an administrative law judge or request a prompt penalty assessment.

"We are greatly encouraged by FERC's enforcement action today against American Efficient, which is fully consistent with the findings of our investigation of its conduct in the MISO markets," MISO Monitor David Patton said. "We continue to encourage MISO to respond to our recommendation to remove energy efficiency from its capacity market or to substantially improve its tariff to eliminate this type of gaming of MISO's capacity market in the future."

In a report attached to the order, FERC Office of Enforcement (OE) staff report allege that, instead of using capacity market revenues to deliver reduced demand, the company and its subsidiaries ran a market research program that determined how much consumption would be avoided if certain products were sold and then bid those savings into capacity markets "as if it caused the savings."

OE said American Efficient did not deliver reductions in consumption, acquire ownership or rights to capacity savings associated with product installations, or "have a nexus with end-use customer projects."

"American Efficient has exploited those markets, enriching itself, its individual investors, its various holding companies, and its investment bank counterparties by receiving capacity payments for a purported energy efficiency project that does not actually do anything to reduce demand," OE said in the report. "Over the past 10 years, the company has cleared half a billion dollars in capacity without offering any real energy efficiency, providing any demand reductions or making the grid any more reliable. Its program receives more capacity payments than any single generator in PJM, and it offers nothing in return."

FERC headquarters in D.C. | © *RTO Insider LLC*

Why This Matters

FERC's order would subject American Efficient to fines and profit disgorgement totaling nearly $1 billion over allegations that its participation in PJM and MISO capacity markets fraudulently characterized the benefits it could deliver.

The report says that, by purchasing "environmental attributes" and sales data associated with products sold at retailers such as Home Depot, Lowe's and Costco, American Efficient claimed to have rights to enter those savings into capacity markets. Enforcement staff, however, argued the company did not inform consumers that it was claiming rights to any capacity associated with their purchase of efficient devices nor did it enter into any agreements with consumers or hold rights over any projects.

The report explained that EE programs typically include a host of measures to reduce demand, including marking down efficient products at the retail level, incentivizing residential consumers to install efficient appliances or incentivizing commercial and industrial customers to retrofit their businesses. Utility programs are subject to review by state commissions through measurement and verification processes.

Third-party programs have included efforts by a university to improve the efficiency of cold water distribution infrastructure and a school district improving lighting and building envelopes across its system.

OE staff analysis found traditional utility EE programs paid $20 to $100 per appliance for direct discounts, while American Efficient paid 15 cents on average. That analysis found the

FERC/Federal News

company paid around $0.001/kWh for energy savings it calculated — around 1% of what utility programs paid.

'At Best Unethical'

The OE report notes the company had been barred from the ISO-NE and MISO capacity markets and that independent market monitors for MISO and PJM both referred the company to the office in April 2021. It also states that American Efficient's policy director left the company and voluntarily provided testimony for Enforcement staff, which wrote that she had "concluded that it had become nothing more than a 'wealth transfer' from ratepayers and was being run in a manner that was 'at best unethical.'"

American Efficient did not inform PJM after being disqualified from MISO and ISO-NE, the report says, and instead expanded its program in the RTO's Base Residual Auctions, increasing to account for nearly three-quarters of EE in PJM. The RTO's stakeholders in August voted to outright eliminate EE from the capacity market , which FERC approved in November (*ER24-2995*). (See *PJM Stakeholders Endorse Elimination of EE Participation in Capacity Market*.)

"American Efficient defrauded the markets and ISO/RTOs by presenting its market data program as a capacity resource," OE wrote in its report. "To carry out that scheme and ensure that it maximized its capacity payments, American Efficient concealed the true nature of the program by making false statements to market regulators. For example, it claimed that it provided 'incentives' and reductions in energy usage. Without any evidence or factual basis, the company also claimed that its program influenced or even dictated customer behavior.

"The company also repeatedly represented to PJM and MISO that its program met the respective tariffs' EER definitions when the program did not. Finally, American Efficient also withheld material information from PJM and MISO to avoid scrutiny of its capacity market activities," the report said.

Responding to the notification that OE intended to recommend an administrative proceeding, American Efficient defended its program by saying neither the RTO monitors nor the investigation had demonstrated fraud. The company argued that PJM had acknowledged in its stakeholder process and FERC filing to eliminate EE from the capacity market that its tariff does not require a causal link between capacity revenues and reduced capacity demand through EE programs. The company said it effectively followed the tariff language and was being expected to comply with anticipated rule changes.

"While the market monitors in PJM and MISO have strong policy preferences that EERs [EE resources] be removed from the markets, they are not arguing (nor could they, based on the record) that American Efficient misrepresented its program when seeking approval," the company wrote. "Instead, the allegations go directly to the fundamental features of American Efficient's EER program. There is no support for the allegation in the preliminary findings that American Efficient had a scheme with an intent to defraud the markets when the features were transparently presented to the RTOs, scrutinized by RTO staff and subsequently approved.

"Put simply, an enforcement action based upon fundamental features of American Efficient's EER program that MISO and PJM knew and approved of would be inequitable."

The company instead recommended that FERC open a technical conference to consider industry-wide changes to how EE participates in capacity markets and how its contributions are measured and verified.

After the Monitors' referrals, American Efficient met with commission staff and argued that it had not violated any FERC or RTO rules and enforcement action was unnecessary. Preliminary findings were presented to the company in July 2023 and a response was submitted the following September.

Enforcement staff sought to interview company personnel, according to the OE report, but American Efficient sent a letter in October 2023 stating that it would not make witnesses available. OE then requested that the preliminary investigation be made formal, which was granted in October 2023. Several former employees and third-party investors spoke with investigators in the proceeding. ■

FERC/Federal News

Parties Lobby FERC for Preferred Paths Forward on Co-location

By James Downing

Supporters of co-locating large loads with generators want FERC to move quickly on rules on the construct, while opponents urged the commission to take its time and make sure it gets the rules right, according to comments filed ahead of a Dec. 9 deadline (*AD24-11*).

The commission had solicited comments on a technical conference held in November on the issue. (See *FERC Dives into Data Center Co-location Debate at Technical Conference*.)

Google told FERC that it is not seeking to avoid paying its fair share of the costs of major new data centers, but that rapid demand growth and slow additions of new supply means the option should be preserved.

"At Google, we ... want to partner in building systems that will support the nation's growing needs in a reliable, secure and cost-effective manner," the firm said. "Co-location arrangements should not be a means to bypass paying for necessary infrastructure, but instead a mechanism to advance well-coordinated and deliberate planning and include appropriate mechanisms to ensure other grid customers are insulated from the impacts of any co-location arrangement."

Co-location can help timely integrate new load and generation, but it is not a substitute for the broader infrastructure investment needed to support load growth, Google said. Ideally, the company wants to use co-location with new generation, but interconnection backlogs have delayed many of those projects.

Another major issue with the growth of data centers is load forecasting uncertainty. Google suggested that FERC require large load developments to make material, upfront commitments before they are included in RTO forecasts.

"For example, as part of their load forecast verification processes, RTOs could require [utilities] to verify that all new large loads have made material upfront financial commitments to be included in load forecasts that underpin near-term (e.g., five-year time horizon) generation and transmission planning tools," Google said.

Beaver Valley Power Station in western Pennsylvania | *Energy Harbor*

Why This Matters

FERC is in the data collection phase of its regulatory process on co-located loads, and it will consider these comments as it decides what to do about the issue.

The same day the tech giant filed its comments with FERC, it announced a partnership with Intersect Power and TPG Rise Climate to build new data centers co-located with new generation. (See *Google Aims to Co-locate New Data Centers with Clean Power Projects*.)

"The partnership will pair new data center facilities with new carbon-free energy resources, with both the load and generation grid-connected and planned in collaboration with relevant grid operators," Google said.

Intersect also filed comments, saying FERC's approach needs to create clarity but avoid impairing future industries and innovations in setting some rules of the road.

"The absence of standard rules, practices and procedures for integrating co-located with new and existing generation (including tariff language and, where necessary, *pro forma* interconnection agreements and procedures) means co-location configurations must go through a laborious, unpredictable, semi-discretionary process to interconnect," Intersect said. "This risks losing the interconnection and transmission efficiencies co-location can otherwise offer."

FERC should support fully isolated, co-located load by recognizing that no transmission rate responsibility is appropriate because to do otherwise would eliminate incentives for large loads to limit their impact on the rest of the grid, Intersect said. However, co-location setups will vary, and FERC should ensure its rules are flexible.

PPL has one of the first co-located loads on its system, in the form of an Amazon data center at Talen Energy's Susquehanna nuclear gener-

FERC/Federal News

ating station, and it said FERC needs to move quickly to set some rules of the road. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

"The easiest solution to the dilemma of behind-the-meter co-located load would be to prohibit it," PPL said. "If the rule was simply that any interconnected load must be served by a public utility, the location of the meter would be irrelevant. Load would likely still co-locate with generation to take advantage of the high levels of reliability on the high-voltage system and to avoid costly transmission upgrades, but that would not itself cause additional reliability or cost-shifting concerns."

FERC likely cannot prohibit co-location because it lacks direct jurisdiction over customers, with Pennsylvania law allowing the Susquehanna deal to go forward, the company said.

"Although these loads are end-use customers, and not directly subject to the commission's jurisdiction, they can reach a gigawatt or more in size," PPL said. "This is two orders of magnitude bigger than the largest retail loads typically interconnected with the electric grid and ... more akin to medium-sized cities appearing rapidly on the system."

Dominion Energy's main utility serves one of the largest data center markets in the world in Northern Virginia and also owns a merchant nuclear plant, the Millstone facility in Connecticut.

"Proper planning and monitoring must be in place to facilitate co-location configurations," Dominion said in its comments. "Due to their significant size, co-located loads can cause operational challenges and impact reliability in certain scenarios."

If the load drops off while the generator is connected to the grid, it will push hundreds of megawatts onto the system, requiring an operational response, or the generator could turn off and lead to a sudden boost in demand, the company said. The impacts on transmission and resource adequacy need to be studied.

"Ideally, the commission should provide the option and flexibility to large load customers to co-locate with new generation," Dominion said. "Co-located load with new generation configurations, if structured properly, can provide several benefits to the grid."

Constellation and Exelon's Dispute Continues in Comments

Constellation Energy and Exelon have been very active in the debate about co-location. The two firms used to be one, so all of Constellation's nuclear plants where it has explored co-location are in Exelon's utility territories.

Constellation urged FERC to move quickly and adopt new rules.

"The rules for connecting and serving new large load such as data centers will significantly impact whether those customers come to PJM, another region or another country, who bears the cost of connecting and serving that load, and how resource adequacy will be ensured," it said.

One thing both sides of the argument agreed on at the conference was that resource adequacy underlies co-location. Constellation argued that the challenges of serving new load are the same regardless of whether it locates behind a generator's meter or on the grid. FERC can do a rulemaking or policy statement to deal with the issues, but Constellation urged it to quickly act on a complaint it filed seeking changes to PJM's rules. (See *Constellation Complaint Seeks Formal Data Center Co-location Rules*.)

"Opponents of prompt action likely will argue that enabling fully isolated co-located load configurations would impair reliability or raise prices for others," Constellation said. "As was clear from discussion at the technical conference, concerns regarding the impact of load growth on reliability and prices are the same regardless of the new load's choice of configuration."

Constellation has argued that the co-location deals it is pursuing will not use the grid, but it said it was open to FERC looking into whether such deals still have the customer using some grid services.

"If the commission believes that PJM's current rules on netting, generator payment for ancillary services or other [matters] must be changed, those discussions should be conducted and resolved as quickly as possible to provide regulatory certainty," Constellation said.

Exelon filed joint comments with East Kentucky Power Cooperative and Southern Maryland Electric Cooperative, which also argued for prompt action.

"These generation units are supported by our electric grid — a network that is relied on, and has been paid for over many decades, by the American public," they said. "Broad consensus emerged during the technical conference that the parties to co-location arrangements should pay their 'fair share' of that grid and the costs of keeping it safe and reliable, without unreasonable cross-subsidization by the consumers who have long supported it."

The issues around artificial intelligence and its future go well beyond FERC's purview and will also need to involve the White House and other agencies, they said.

"New policies providing special treatment exclusively for co-located data centers are not needed for the data center industry to thrive — whether in the name of national security or otherwise," they said. "In contrast, promoting a regulatory environment that hastens the development and interconnection of generation and transmission infrastructure for all end users, rather than a small subset, will benefit domestic development of AI and other industries that have a national security interest."

Two Consultants with PJM Experience Weigh in

Suzanne Glatz and Abraham Silverman, consultants who worked in and around, respectively, PJM for years, filed comments arguing that data center co-location deals might appear the same as other load interconnections from an engineering perspective, but not a regulatory or transmission cost allocation perspective.

Generators do not pay for transmission service, while grid-connected loads with on-site generation do, and they have vastly different rate impacts.

"To be fully isolated, a facility must disconnect from the grid," they said. "Some commenters have suggested a co-location load is fully isolated when protection devices are installed to prevent the load from taking power from the grid. This does not constitute isolation and does not change the fact that the co-location configuration is connected to the grid and using the grid. Otherwise, a generator would simply isolate from the grid and serve the load directly."

They suggested FERC put such arrangements in the same processes that account for other changes in system load to ensure that they are treated equally. Another option would be to put co-location deals in the interconnection process.

"This option requires updating the interconnection process," they said. "For example, the current interconnection processes do not, and are not designed to, account for behind-the-generator-meter-connected load. New tariff requirements would have to be developed in order to incorporate the additional data needed to account for addition of the customer load and other electrical parameters of the customer facilities needed to perform reliability studies." ■

FERC/Federal News

Lame Duck Permitting Push Fails; Manchin Blames House GOP Leaders

By James Downing

The bipartisan permitting bill that passed the Senate Energy & Natural Resources Committee is officially dead, with Sen. Joe Manchin (I-W.Va.) saying Dec. 16 it would not be included in a must-pass spending bill.

Manchin blamed House Republicans, specifically Majority Leader Mike Johnson (R-La.), as negotiations around the issue failed and it will not be included in the last legislative vehicle to make it out of this Congress.

"By taking permitting off the table for this Congress, Speaker Johnson and House Republican Leadership have done a disservice to the incoming Trump administration, which has been focused on strengthening our energy security and will now be forced to operate with their hands tied behind their backs when trying to issue permits for all of the types of energy and infrastructure projects our country needs," Manchin said.

While Republicans are poised to also take control of the Senate next year, their 53-47 majority will require votes from Democrats for meaningful permitting reform, he added. Reforming the National Environmental Policy Act, FERC's governing statutes and other relevant laws is too far afield from the budget to be eligible for the reconciliation process that avoids the 60-vote threshold, which Democrats used to pass the Inflation Reduction Act.

"I am very proud of the work that my friend and partner, Sen. John Barrasso, and I put in over the course of nearly two years with our colleagues on the Senate Energy & Natural Resources Committee to get the Energy Permitting Reform Act negotiated, drafted and through the committee process with a historic 15-4 favorable vote, sending a clear signal that the time is now to get this done," Manchin said.

As Congress was negotiating what would be included in the continuing resolution it needs to pass by the end of this week to keep the government funded, a broad group of trade associations asked for its passage.

The American Council on Renewable Energy, American Chemistry Council, Advanced Energy United, Center for LNG, Clean Energy Buyers Association, Electric Power Supply Association, National Mining Association, Solar Energy Industries Association, the U.S. Chamber of Commerce, and dozens of others signed onto a letter urging Congress to pass a bill.

"America's energy industry is united in one common goal — providing affordable, reliable, cleaner domestic energy," the letter said. "But our current permitting system frequently prevents us from accomplishing that goal, bogging down our projects in bureaucratic delays and endless litigation. For example, it can take, on average, up to 10 years to permit a single transmission line and 29 years to move mining projects through the federal permitting process, 3-8 years just for litigation."

Another letter from 25 conservative and "free market" groups, led by the Competitive Enterprise Institute, urged Congress to wait until its next session to pass permitting legislation. They specifically argued against increasing the federal role in electric transmission siting.

"It makes no sense for Republicans to move forward with legislation now when next year they will control the House, the Senate and the White House," the CEI-led letter said.

"Anything that Republicans and those who want genuine permitting reform can get now they can get next year, and much more. There would be less need for compromise, such as by enacting harmful transmission policy that would untap the Inflation Reduction Act subsidies and primarily serve to put unreliable electricity generation on the grid (i.e. wind and solar)." ■

| Shutterstck

CAISO/West News

Pathways Step 2 Not Good Enough, Markets+ Backers Say

By Henrik Nilsson

The West-Wide Governance Pathways Initiative still grapples with political uncertainties and governance concerns despite efforts to fix those issues as it seeks to create an independent "regional organization" (RO) to oversee CAISO's Western electricity markets, proponents of SPP's Markets+ contend.

The claim came in a Dec. 6 *addendum* to the first "issue alert" on governance the Markets+ backers *published* Aug. 7. The proponents have issued several alerts to highlight the purported advantages of Markets+ over CAISO's Extended Day-Ahead Market (EDAM).

The contributors include Arizona Public Service, Chelan County PUD, Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association and Tucson Electric Power — all of whom helped fund the Phase 1 development stage of Markets+.

The addendum is a response to the West-Wide Governance Pathways Initiative's Launch Committee *voting to approve* its "Step 2" proposal, which divides functions between CAISO and the new independent RO backers seek to create to oversee the ISO's Western real-time and day-ahead markets.

While recognizing the work that went into developing Step 2 and the "incremental benefits" it would provide, the Markets+ proponents argued the plan failed to resolve key issues, such as independent governance and broader political support.

The addendum noted that under Step 2, the Pathways Initiative must secure a legislative change in California to establish the RO and grant it power to set market policy for EDAM, while CAISO would "retain its current balancing authority and market operator roles."

Tacoma Power is among the utilities contributing to the addendum to the first "issue alert" in favor of SPP's Markets+. | *Tacoma Public Utilities*

"The success of the Step 2 Proposal depends on uncertain future events including legislation in California that has not yet been developed or approved and subsequent implementation of that legislation by the California ISO Board of Governors and other entities," the addendum stated.

Additionally, while Step 2 will "provide incremental benefits to all energy markets in the West," the question of whether the proposed RO will be independent of CAISO has not been resolved, according to the Markets+ backers.

"This includes a single shared tariff and an intertwined relationship across numerous areas, such as shared staffing, and financial and regulatory responsibilities associated with the organization being borne by CAISO," the addendum said. "In addition, CAISO would be responsible for day-to-day market operations with limited supervision by the RO."

The Markets+ backers contend it's "not clear whether any future California legislation will enable the CAISO BAA to be part of any RTO governed by the RO."

The addendum also raised concerns over transparency in the selection of the Step 2 Formation Committee, uncertainty about how the RO would address costs and cost allocation, and the risk to Western ratepayers outside the CAISO BAA "until a fully independent governance structure is eventually achieved (if ever)."

Pathways supporters have addressed some of the concerns raised in the addendum. In October, key backers of Pathways *told state energy officials* they're confident California lawmakers will pass legislation next year to relax state oversight on CAISO's markets and establish the RO. Pathways supporters in California have begun discussions with legislative staff who likely would contribute to crafting the bill.

The Pathways initiative *also has won over previous skeptics*, with the International Brotherhood of Electrical Workers indicating they will sponsor the legislation needed to implement Step 2.

Kathleen Staks, executive director of Western Freedom and Pathways Launch Committee co-chair, cited the Step 2 proposal in an email to *RTO Insider* on Dec. 9, stating the plan lays the foundation to "enable the West to create a suite of voluntary wholesale electricity market services as stakeholders and participants desire and require, with each state retaining its unique decision-making autonomies and participating on a level playing field."

Staks noted that the Launch Committee "is not engaging in any legislative efforts" and "[a]ny future legislative needs will be determined by the RO and western stakeholders and the CA legislature."

"The proposed legislative scope for 2025 does not include a change to the CAISO BAA," Staks added. "The Launch Committee did include a section in the proposal about a potential scenario for co-optimization of the transmission system … that could be possible without further legislative change." ■

Why This Matters

Markets+ backers have been consistent in their skepticism that a Western regional organization that is built around CAISO could provide fully independent market governance, administration and operations.

CAISO/West News

CAISO Monitor: ISO Easily Handled Annual Peak Demand in 2024

CAISO's Department of Market Monitoring on Dec. 12 *reported* that the ISO saw "one of the highest demand peaks" in recent years, at 48,353 MW on Sept. 5 — but still well short of the record of 52,061 MW in 2022.

Speaking at the ISO's Market Performance and Planning Forum, Guillermo Bautista Alderete, the department's director of market analysis and forecasting, highlighted that the peak was also higher than the California Energy Commission's forecast of 47,160 MW.

Annual CAISO demand typically peaks in July to mid-September. Besides the 2022 record, this year's figure marked the highest peak load since Sept. 1, 2017, when demand rose to 50,116 MW. It was also an increase of about 8.6% over last year's 44,534 MW on Aug. 16.

Monthly resource adequacy showings, which came out to be a little over 53,000 MW, slightly increased from 2023 and were sufficient to cover CAISO's load plus operating reserves in September. That was "the reason why we didn't have any tight supply conditions to the extent that we have observed in previous years," Alderete said.

Why This Matters

Despite an increase in CAISO's peak load in 2024 compared with last year, an increase in battery energy storage and a robust fleet led to sufficient supply to meet the demand.

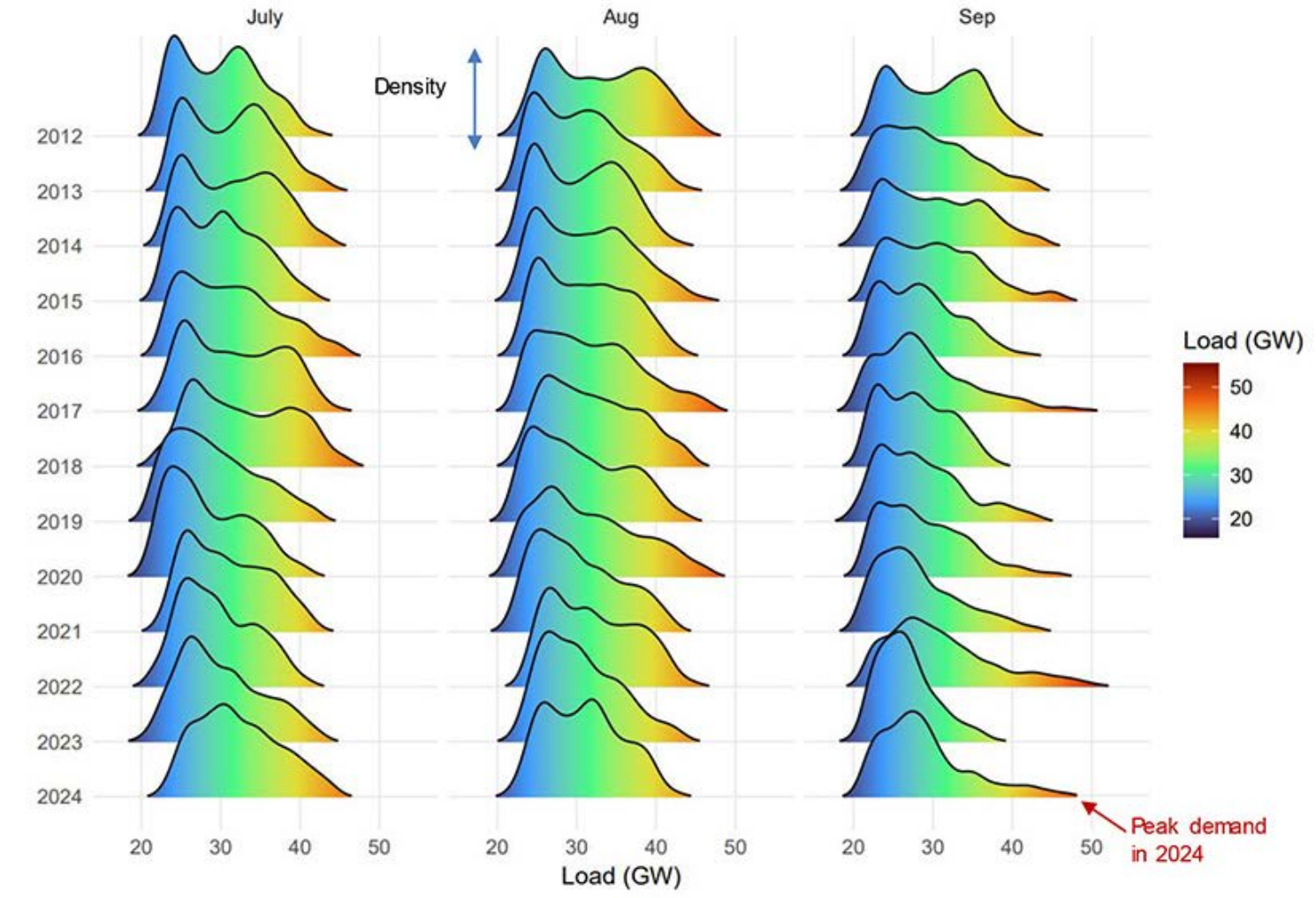
He also noted that there was a significant decrease in gas-fired generation coupled with a significant increase in storage resources: 3.6 GW compared to 5.5 GW.

"That aligns with the present trend that we have seen of quick penetration of storage resources exceeding the 10,000-[MW] mark sometime in 2024," Alderete said.

Despite what Alderete described as a relatively moderate September, the ISO did support a "reasonable level" of wheel-through transactions, peaking at just over 500 MW.

September also saw the highest participation in the Assistance Energy Transfer (AET) program since its inception in 2023. Nine balancing authority areas opted into the program, accumulating approximately $720,000 in AET surcharges in August and September. ■

— Ayla Burnett



CAISO's peak demand for 2024 occurred Sept. 5, at 48,353 MW. | *CAISO*

CAISO/West News

Panel: NW Region Must Get Creative to Tackle Data Center Demand

By Henrik Nilsson

To meet the electricity demand expected from new data centers in the Northwest, stakeholders must collaborate to efficiently invest capital and explore controversial solutions like establishing a regional transmission organization, panelists said in a webinar hosted by the Northwest Power and Conservation Council on Dec. 11.

The companies building data centers have "extraordinarily" deep pockets, which means there are a lot of opportunities to fund large infrastructure projects on the backs of individual customers, according to Brian Janous, co-founder and chief commercial officer at Cloverleaf Infrastructure.

Companies already have showcased their willingness to fund energy infrastructure, Janous said.

Some *recent examples* include GE Vernova and ExxonMobil announcing new natural gas projects to meet data center demand. On Dec. 10, Google *partnered* with renewable energy developer Intersect Power and clean energy investor TPG Rise Climate to power the search giant's data centers.

"The problem that we have is not that there's not capital," said Janous. "The problem we have is there's not that many opportunities right now to invest that capital efficiently."

Planners need to change their mentality around flexibility and speed to boost investments in power systems and other benefits data centers can bring to a region, Janous said.

Robert Cromwell, consultant and former vice president of power supply at the Umatilla Electric Cooperative, agreed.

"There is an enormous opportunity for the balancing authority areas or the transmission service providers to integrate operations with the data center campuses when they're built," Cromwell said.

But council member Douglas Grob questioned whether it's possible to integrate data center customers at the speed they ask for, saying states are slowed by their own rules and court systems.

Cromwell said the answer "would be a regional transmission organization or an independent system operator where all the different balancing authorities in the West merge and you have a single entity that's dispatching load and generation collectively."

Cromwell said there's growing recognition RTOs are a more efficient approach, "but it runs directly contrary to some of the core values within public power."

"It's something that just rubs a lot of people the wrong way, and you've just got to be honest about that," Cromwell said. "But candidly, I've been working on these issues for a good chunk of my career, and I don't see another path that will solve our problem."

Panelists on a webinar hosted by the Northwest Power and Conservation Council argued for creative solutions to meet new power demand. | *Shutterstock*

Notable Quote

"The problem that we have is not that there's not capital," said Brian Janous, co-founder and chief commercial officer at Cloverleaf Infrastructure, a developer of sites for large electric loads. "The problem we have is there's not that many opportunities right now to invest that capital efficiently."

Sarah Smith, a research scientist with the federally funded Lawrence Berkeley National Laboratory, said there's an opportunity to be creative, but it "will take some new ideas and new models."

Smith noted the federal government is focused on speeding up new transmission by improving the permitting process and the interconnection queue, "both on the generation side and the load side."

However, there are other avenues for regions to successfully attract data centers, which can be advantageous for local governments, Smith said. For example, data centers can repurpose old mining sites that already have power infrastructure in place, and "you wouldn't have to reenter that interconnection queue," Smith added.

Finding sites "where it's more feasible to add that load in the short term" can provide regions a chance to offer those sites to data centers so that the "industry isn't making requests that are really hard to meet when there might be other sites and options on the table," Smith said.

The Northwest Power and Conservation Council hosted the webinar shortly after the WECC *published* a report that forecasts "staggering" growth in electricity demand in the Western Interconnection over the next decade.

The report predicts annual demand in the Western Interconnection will grow from 942 TWh in 2025 to 1,134 TWh in 2034. That 20.4% increase is more than four times the 4.5% growth rate from 2013 to 2022 and double the 9.6% growth forecast in 2022 resource plans. ■

CAISO/West News

FERC Approves Fines on Batteries for Misleading Bids in CAISO

By Ayla Burnett

FERC on Dec. 5 approved a consent and stipulation agreement between its Office of Enforcement and the operators of two battery storage projects in CAISO imposing nearly $3.5 million in fines on the companies for submitting inaccurate initial state of charge values that led to undue bid cost recovery (BCR) payments (*IN24-13*).

Sonoran West Solar Holdings 1 and 2, owned by RE Crimson, agreed to disgorge the $2,473,265 in BCR payments they received from Oct. 1, 2022, through Feb. 17, 2023, and pay a $1 million civil penalty to the U.S. Treasury. The companies stipulated to the facts of Enforcement's investigation but neither admitted nor denied any violations.

The Sonoran entities each operate a battery at the Crimson Battery Project in California's Riverside County. Crimson 1 is a 200-MW/800-MWh battery, and Crimson 2 is 150 MW/600 MWh.

According to the CAISO tariff, if a battery submits a day-ahead bid at 10 a.m., it has the option to forecast its state of charge at the beginning of the next operating day, referred to as the battery's "initial state of charge."

Enforcement found that during the relevant period, the Sonoran entities frequently submitted biddable initial state of charge parameters to CAISO that reflected a value that was other than a "forecasted starting physical location," or the state of charge the batteries were forecasted to hold at the start of the real-time market.

The companies submitted initial state of charge values indicating their batteries would be available to receive discharge awards at midnight and the early morning hours of the following day. On average, Crimson 1 and Crimson 2's initial state of charge values were 480 MWh and 426 MWh higher, respectively, than their telemetered state of charge at midnight.

Additionally, on Oct. 24 and Nov. 28, 2022, and Jan. 14 and 15, 2023, the companies submitted outage cards with a maximum stored energy of 0 MWh, indicating that the battery needed to be fully discharged in advance of the outage. As a result, they received day-ahead awards to discharge to sell energy prior to the outages.

Sonoran West Solar Holdings in Riverside County, Calif. | *NREL*

Why This Matters

The Crimson Battery Project received undue bid cost recovery payments after submitting misleading initial state of charge values — a problem that CAISO has been working diligently to mitigate within its Storage Bid Cost Recovery and Default Energy Bids Initiative.

Because the day-ahead bids were at or near the CAISO bid cap of $1,000, the awards were uneconomic and resulted in BCR payments they would not have obtained if they had submitted accurate information. CAISO's Department of Market Monitoring flagged the payments and, after department inquiries and Enforcement's investigation began, the Sonoran entities began implementing processes to minimize future likelihood that initial state of charge and maximum stored energy for outages would be misreported.

Enforcement determined that the initial state of charge values submitted to CAISO during the relevant period were "false and misleading" because they did not reflect a forecasted physical starting location, nor the reasonably expected availability of its batteries at midnight.

The companies will also submit an annual compliance monitoring report to Enforcement for at least one year.

FERC found "that the agreement is a fair and equitable resolution of the matters concerned and is in the public interest." It directed CAISO to allocate the disgorged funds in its discretion for the benefit of ISO customers.

CAISO and stakeholders have been working over the last six months "to evolve existing bid cost recovery rules for energy storage resources to ensure fair and equitable treatment of these resources and reduce unwarranted bid cost recovery payments," ISO spokesperson Anne Gonzales said.

The ISO is kicked off a new initiative Dec. 11 to continue addressing the issue. (See related story, *CAISO Launches New Initiative for Storage Resource Design*.) ■

CAISO/West News

CAISO Launches New Initiative for Storage Resource Design

Working Group Addresses Storage BCR, Seeks to Modify Default Energy Bid

By Ayla Burnett

CAISO on Dec. 11 kicked off a new *Storage Design and Modeling Initiative* intended to tackle an array of challenges related to the market participation of storage resources, including further addressing bid cost recovery (BCR) issues and developing a default energy bid (DEB) formula specifically for batteries.

The initiative piggybacks off the ISO's prior storage BCR working group, which identified that BCR provisions don't align with storage resources and led to passage of a proposal to modify the calculation used to determine BCR payments. (See *Proposal to Refine Bid Cost Recovery for Storage Passes Unanimously*.)

But several stakeholders, along with CAISO's Market Surveillance Committee and Department of Market Monitoring, emphasized that the proposal was only a first step in addressing the number of problems identified with storage BCR and their default energy bids.

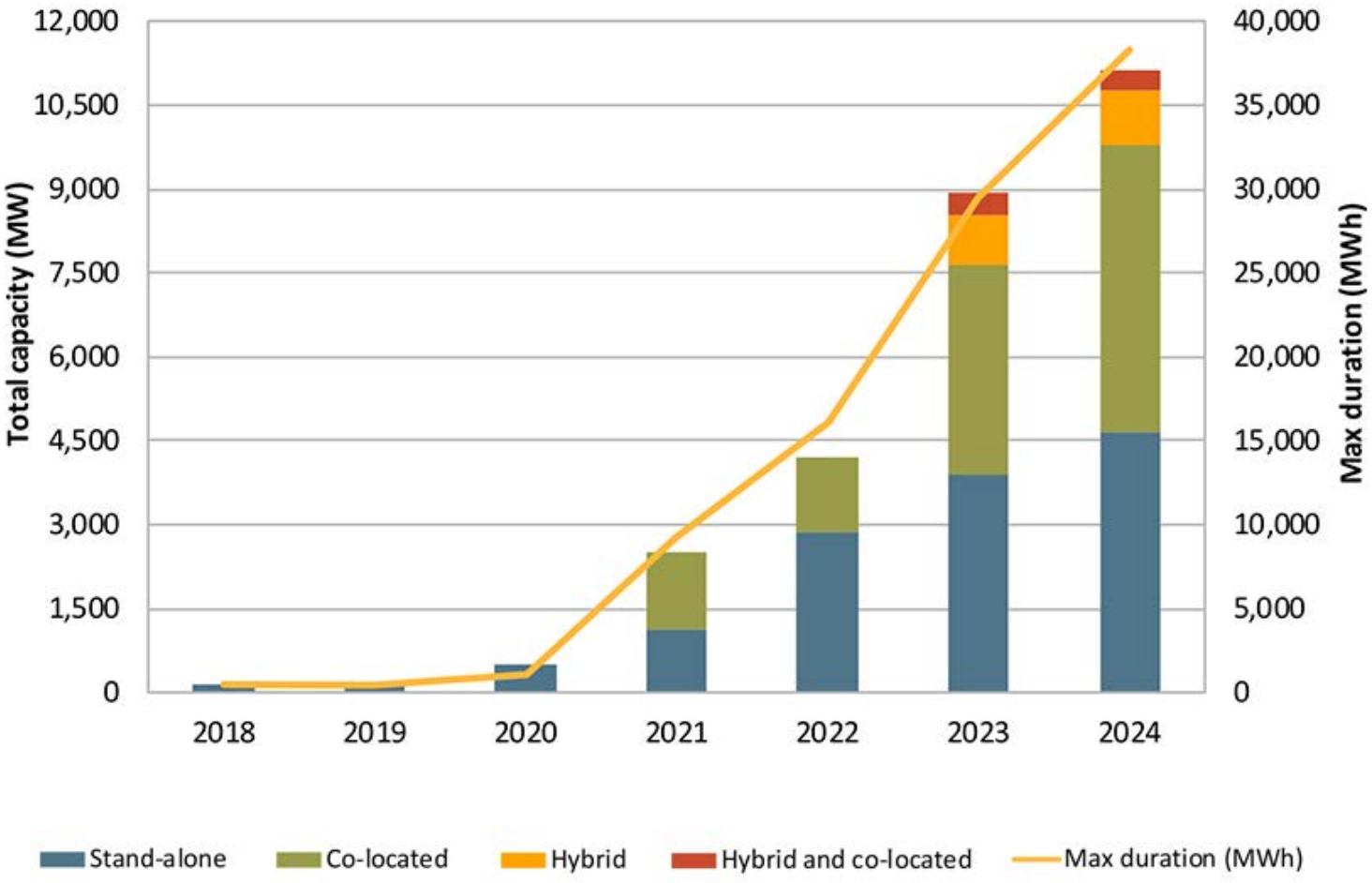
The new initiative will delve into previously identified problems, including the need for a holistic redesign of the uplift mechanism for storage and changes to the DEB that reflect the specific characteristics of the resources. It will also introduce new ideas designed to further integrate batteries efficiently into the ISO market, including a proposal to develop a state-of-charge (SOC) mechanism and a way for storage batteries to bid into the market based on their SOC.

The working group's effort will be separated into three topic groups: The first deals with BCR, the DEB and outage management systems (OMS); the second covers all topics related to state-of-charge management; and the third deals with distribution-level and paired resource topics.

Bid Cost Recovery, Default Energy Bid Modification

While CAISO's completed storage BCR and DEB initiative closed a major market design gap related to existing BCR for storage resources, the ISO identified a further need to address storage assets' lack of exposure to real-time prices if they deviate from their day-ahead schedules. As a result, the new initiative will seek to redesign the storage uplift mechanism, Sergio Dueñas Melendez, storage sector manager at CAISO, said during the meeting to launch the effort.

In prior working groups, stakeholders also recommended modifications to the storage DEB and the desire to consider standard approval



Active battery capacity in CAISO balancing area (2018–2024) | *CAISO*

CAISO/West News

for storage reference level change requests, which are currently manually processed by ISO staff. Automation and standard approval would provide clarity for market participants, Dueñas Melendez said.

Lastly, the ISO is seeking to enhance the outage management system (OMS) to align with storage resources, which includes reviewing lower and upper SOC real-time biddable parameter use, clarification of how SOC physical outages impact Pmax and Pmin outages, and improvement of OMS functionality to better support outage submissions from storage assets.

State-of-charge Management

The ISO is considering developing a "system SOC" mechanism that would track total energy available across the entire storage fleet.

"Thinking about the fleet holistically may allow better optimization of that storage fleet in critical conditions," said Dinesh Das Gupta, policy developer at CAISO.

The system SOC mechanism will work in tandem with how the market operates, so it would be an addition to the system, not a replacement.

CAISO is also considering developing a "biddable SOC market participation pathway" that would allow energy storage resources to offer charge and discharge bids in relation to their SOC.

"The vast majority of storage resources participate in the market through the non-generator resource model, which approximates values through megawatt price bid pairings," Das Gupta said. "A new pathway option centered on bidding at a given SOC may address multiple needs that are currently not found with the non-generator model."

Why This Matters

CAISO has the largest presence of battery storage of any grid in the nation, and this latest initiative could become a model for other grid operators as they seeing growing adoption of those resources.

Developing this new pathway would take additional time from a policy and technical perspective, Das Gupta highlighted.

The ISO also highlighted the need to modify the SOC definition and calculation, after determining that resources may face physical constraints not reported to the market that prevent dispatch. Refining how SOC is defined and calculated would improve the ISO's confidence in a storage resource's ability to follow dispatch signals during tight system conditions, Das Gupta said.

The working group will also consider the non-linearity of a storage resource's SOC. Non-generator resources are modeled linearly, but energy storage resources have nonlinear maximum charging and discharging abilities. Better accounting for this nonlinearity, especially under extreme conditions, may improve storage resource performance, Das Gupta said.

Finally, the ISO highlighted the need to explore SOC management for capacity awards. The current SOC calculation doesn't fully model the impacts of capacity awards, particularly for the ISO's flexible ramping product, which could result in storage resources being unavailable for other commitments, potentially jeopardizing reliability.

"With the flexible ramping product, we're seeing potentially serious implications given the price of the product and the high percentage of the product being provided by storage resources," Das Gupta said.

Distribution-level Resources

Distribution-level storage assets provide wholesale energy storage to the system via the distribution network rather than through a direct interconnection at the bulk transmission level. These assets fall under both the ISO tariff and the distribution level tariff, and aligning the two would "enhance operational confidence for both resources," Das Gupta said.

Additionally, due to significant growth in co-located resources, each with unique parameters and challenges, the ISO is also seeking to explore settlement provisions, including BCR, following increased operational experience with co-located resources.

The last effort in this topic group seeks to address the lack of a DEB for hybrid resources. Developing a bid for such resources would allow bidding up to the soft-offer cap.

Next Steps

CAISO expects to release a straw proposal for the initiative in March 2025, with a final proposal slated for July. ■

CAISO/West News

Puget Sound Energy Signs on with North Plains Connector

HVDC Tx Line to Link MISO, SPP and the Western Interconnection

By Elaine Goodman

Puget Sound Energy has become the latest utility to stake a claim in the North Plains Connector, a 420-mile transmission line from central North Dakota to southeast Montana.

PSE signed a nonbinding agreement with Grid United's North Plains Connector LLC to buy 750 MW of transfer capacity on the 3,000-MW line — a 25% share. Financial terms weren't disclosed for the deal, announced Dec. 9.

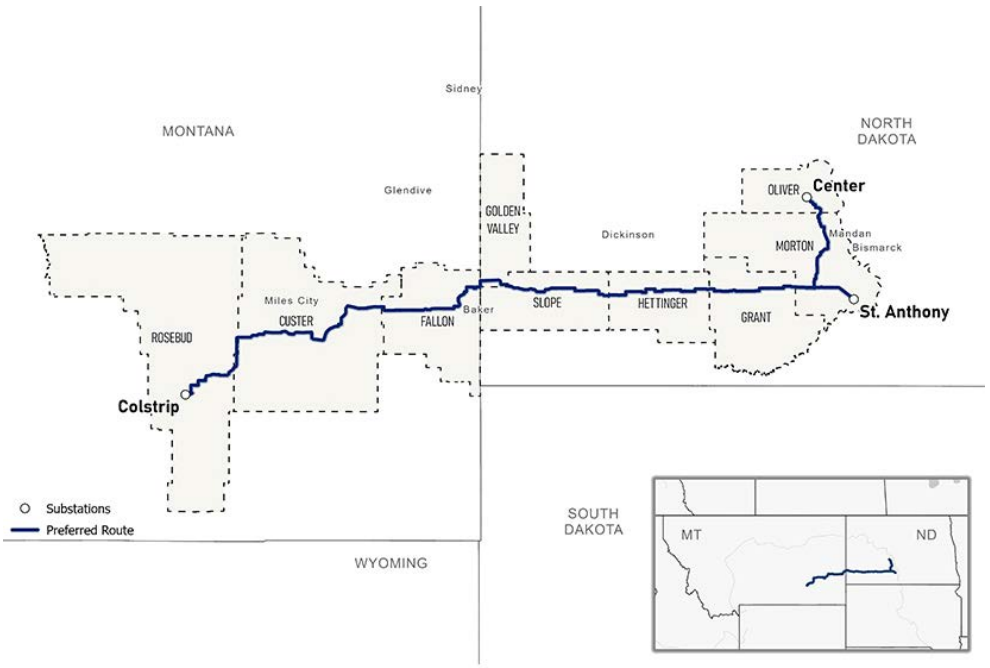
Grid United, a competitive transmission developer, is partnering with Minnesota-based energy company ALLETE to develop the North Plains Connector. The project is billed as the first high-voltage direct-current (HVDC) transmission link among three regional energy systems: MISO, SPP and the Western Interconnection.

ALLETE will pursue up to 35% ownership of the $3.2 billion project and would oversee the line's operation, under an agreement with Grid United announced in December 2023. The North Plains Connector is expected to start operations in 2032.

In May, Portland General Electric announced a nonbinding agreement with Grid United and ALLETE in which PGE is expected to hold a 20% ownership share of the project.

That was followed by Avista's announcement in November of a nonbinding agreement for 300 MW of transfer capacity, or a 10% ownership share. Avista Utilities provides natural gas and electric services to customers in eastern Washington, northern Idaho and parts of Oregon.

Grid United will continue to fund the development of the North Plains Connector. PSE and PGE would invest when regulatory approvals and permits are in place. Avista would invest when the project is operational.



Proposed route of the North Plains Connector transmission line. | *Grid United*

Why This Matters

The project is seen as a way to reduce transmission congestion while allowing rapid sharing of energy resources across a vast area with diverse weather patterns and in different time zones.

Grid Benefits

The North Plains Connector will run between endpoints near Bismarck, N.D., and Colstrip, Mont. The line of up to 525 kV will be open to all sources of electric generation.

The project is seen as a way to reduce transmission congestion while allowing rapid sharing of energy resources across a vast area with diverse weather patterns and in different time zones.

The transmission line "will play an important role in enhancing the reliability and resilience of the Western grid," Josh Jacobs, PSE's vice president of clean energy strategy and planning, said in a statement. "It will be a critical link connecting PSE and its customers to new markets that can provide needed resource diversity to aid in the clean energy transition."

And after it's built, the transmission line is expected to promote energy production in Montana and North Dakota.

The project got a boost in August with the award of a $700 million Grid Resilience and Innovation Partnerships (GRIP) grant from the U.S. Department of Energy to the Montana Department of Commerce. The project began the National Environmental Policy Act (NEPA) process for federal permitting in October.

Grid United and ALLETE first announced plans for the North Plains Connector in early 2023. (See *Transmission Project Would Span Across Interconnection Divide*.)

A study by Astrapé Consulting found that the North Plains Connector could unlock 3,550 MW of capacity across MISO, SPP and the Western Interconnection. The capacity benefit represents the amount of additional demand that could be served without degrading reliability standards. (See *Study: Significant Benefits for Merchant Tx Line*.)

The study modeled the North Plains Connector as two 1,500-MW HVDC lines connecting SPP and MISO to the Western grid. Results were released in June.

Kris Zadlo, Grid United's president and chief technical officer, said at the time that the study could encourage deeper analysis of the benefits of interregional transmission projects.

"By shedding light on how grid-connecting projects like NPC [North Plains Connector] enhance reliability and reduce the risk of power outages, we can build a better connected, more resilient grid for the future," Zadlo said in a statement. ■

CAISO/West News

FERC OKs CAISO Plan to Streamline Interconnection Process

ISO Requested Tariff Changes to Speed up Process for Cluster 14 and Earlier

By Ayla Burnett

FERC on Dec. 16 approved CAISO's request to further streamline its generator interconnection process in response to the high volume of requests in its interconnection queue.

The commission's order permits the ISO to apply six sets of tariff revisions related to its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and associated Generator Interconnection Agreements (GIAs) to resources that joined the queue in Cluster 14 — which opened in April 2021 — or earlier.

The tariff revisions won't apply to interconnection customers that already have executed GIAs or have requested that GIAs be filed unexecuted.

In September, FERC approved a larger proposal to streamline the ISO's interconnection process starting with 2023's Cluster 15 and beyond. (See *FERC Approves CAISO Plan to Streamline Interconnection Process*.)

The newest tariff amendments are intended to manage the "large volume of interconnection requests already studied but for which GIAs have not yet been executed," the commission noted in its order (*ER25-131*). The revisions are a result of the ISO's Interconnection Process Enhancements (IPE) initiative, which involved over a year of stakeholder engagement that led to the approval of refinements to the process.

The IPE proposal is intended to complement — not replace — CAISO's FERC Order 2023 compliance filing, which is still pending approval. The order states that, while the tariff revisions in the most recent filing touch on some reforms in the Order 2023 filing, "CAISO does not propose revisions to any section of its tariff pending commission acceptance."

The six sets of tariff revisions the commission approved Dec. 16 will:

- Subject new small asynchronous generating facilities in Clusters 14 or earlier to fault recording requirements that CAISO currently applies only to asynchronous generating facilities larger than 20 MW.
- Update the granularity of phase angle measuring unit data for asynchronous facilities by increasing the sampling rate of that data.
- Unify the payment and authorization schedules among interconnection customers sharing network upgrades to develop a construction timeline necessary to meet the earliest interconnection customer's commercial operation date.
- Increase the material modification assessment (MMA) deposit cost from $10,000 to $30,000 and extend the estimated time to complete an MMA from 45 days to 60 days.
- Create a new "implementation deposit" of $35,000 to cover specific customer costs after completion of interconnection studies in order to avoid passing off those costs to other market participants.
- Limit the ability of a customer to linger in the queue after it gives up its deliverability rights.

Why This Matters

FERC's approval should allow CAISO to move more quickly through the backlog in its generator interconnection process.

The commission said CAISO's proposals "will improve the accuracy of data about the system, help mitigate reliability issues, enhance the certainty and efficiency of the network upgrade process, ensure that the costs of managing interconnection requests between GIA execution and commercial operation are not allocated to all market participants, and reduce administrative overhead."

The new rules become effective Dec. 17. ■

Robert Mullin contributed to this article.

The number of interconnection requests in CAISO's cluster 14. | *CAISO*

ERCOT News

ERCOT's Vegas Touts New Reliability Standard

By Tom Kleckner

Keynoting the Texas Reliability Entity's December board meeting, ERCOT CEO Pablo Vegas touted the ISO's development of a new reliability standard for the market as "one of [our] more significant" accomplishments.

He said rather than focus on an outage event's frequency risk — the loss-of-load expectation, generally set at once every 10 years — as do other grid operators, ERCOT's reliability standard will measure frequency (one in 10), duration (no more than 12 hours in any event) and magnitude.

"When you couple or put together all three of those pieces and parts, you have a comprehensive reliability standard that better characterizes what the real risk probabilities are of a grid event and what the impact characteristics would be to consumers in the region," Vegas told the Texas RE Board of Directors on Dec. 11.

ERCOT staff are finalizing the magnitude element and working on the various parameters and scenario modeling for the new standard, Vegas said.

"We want to set it at a level where it's reasonable to rotate outages should you get into that scenario, so that people who experience a grid-related outage would not have an elongated, continuous outage, but rather would have the opportunity to have power restored as those rotating outages move through different customer groups," he said.

The Public Utility Commission approved the reliability standard's framework in August. Criteria deficiencies are to be assessed at least once every three years, beginning in 2026. The PUC will approve the modeling assumptions and include a public review before the assessment begins. ERCOT is required to develop market design options that address the expected deficiencies.

"The way this is going to be used effectively, we're going to now have a yardstick that is going to effectively help us measure how we think the ERCOT market will perform in some period of time," Vegas said. "I'm really excited to have the first really formal reliability standard in the ERCOT market with the completion of this work."

Vegas also briefed the Texas RE on the "remarkable load growth trajectory" ERCOT expects over the next five to 10 years — an additional 65 to 150 GW by 2030 — that could grow the oil-rich West Texas load zone to nearly the size of Houston, the nation's fourth-most populous city. AI data centers, crypto miners and other large loads have accounted for about 63 GW seeking interconnection to the grid, he said.

In response, ERCOT is considering 765-kV transmission backbones and trying to add smaller infrastructure as quickly as possible. The continued wave of energy storage and solar facilities is useful in meeting demand during tight periods and providing ancillary services.

Alluding to the energy transition and thanking Vegas for his presentation, board Chair Jeff Corbett said, "All those of us in this world, we're reading this every day, but when you come and talk about it, you put it in a nice package that allows us to actually take a step back and go, 'Crap!'

"But I will say that I do sleep OK at night because Pablo is at ERCOT."

In other business:

- The board endorsed the Nominating Committee's recommendation that Corbett continue to serve as chair and Suzanne Spaulding as vice chair in 2025.
- The Texas RE's membership has dropped from 125 members to 107. Generation resources account for the bulk of the entity's members, with 74. ■

Why This Matters

ERCOT's reliability standard measures not only the loss-of-load expectation for an outage event but also its frequency and magnitude, unlike most other grid operators. The grid operator says this will result in a comprehensive reliability standard that better characterizes the real risk probabilities of a grid event and its impact to consumers.

ERCOT CEO Pablo Vegas shares his thoughts with Texas RE's Board of Directors. | © *RTO Insider LLC*

ERCOT News

Texas Public Utility Commission Briefs

Regulators to Consider Staff's Recommendation to Revise PCM

The Texas Public Utility Commission's staff has recommended not moving forward with the proposed performance credit mechanism (PCM) market design for ERCOT as it currently is designed, setting up an interesting decision for the PUC in its final open meeting of the year.

A day after the commissioners agreed to delay any decision until that Dec. 19 meeting, staff said in a *Dec. 13 filing* that the PCM market tool results in "minimal" additional resource adequacy value under its current design parameters. They also said alternative design choices would result in the PCM not complying with state law, and market modifications likely will be needed to achieve the PUC's chosen reliability standard in the long term (*55000*).

"We intend to bring this back on the 19th and make a decision on where to go forward from there with the PCM," PUC Chair Thomas Gleeson said during the commission's Dec. 12 meeting.

"There's still a lot up in the air, right?" Commissioner Lori Cobos said. She referenced ERCOT's stand-alone dispatchable reliability reserve service still under development, the Real-time Co-optimization plus Batteries project, and important questions surrounding the ancillary service demand curves, all of which are to be brought online before the PCM.

"You have to put those into a structure then and put them into operation and be able to get this analysis to be able to understand whether [they're] working or not," Cobos said.

Gleeson said during a conference in September the PCM should be placed on the back end of other market changes.

"We have a number of tools at our disposal. We should try to see if we can meet our reliability goals with those tools before we look to implement something that's new and novel and that we don't really know how it interacts with the rest of our market," he said at the time. (See "Market Participants Pan PCM," *PUC's Gleeson at Texas Clean Energy Summit: Smooth Tenure Turns 'Interesting'*.)

The commission in August directed ERCOT and the Independent Market Monitor to complete updated assessments on the PCM's cost to and effects on the market and file a report on the costs and benefits of continuing the program. Staff then reviewed the assessments before making their recommendation.

Jimmy Glotfelty prepares to adjourn his final PUC meeting. | *Admin Monitor*

Staff said the *ERCOT assessment*, conducted with the Energy and Environmental Economics (E3) consulting firm, recommended refinements to the PCM's design be considered so the tool could have a more substantive impact on reliability before eliminating it as a potential option.

The IMM *found* the PCM to be a "novel form of a capacity market" in that it settles based on after-the-fact availability rather than ex-ante based on expected availability. Staff noted the monitor also concluded the PCM would provide a new source of revenue for generators that would increase ERCOT's capacity margin and the costs to customers but reduce shortage revenues.

The monitor said the PCM's net costs are likely to exceed $1 billion annually in the short term because its cost cap provision is likely to bind. Eventually, the higher capacity margins would reduce the frequency of shortage pricing, with the net costs falling to $350 million to $725 million per year. Without the cost cap, those costs would range from $930 million to $2 billion, the IMM said.

The PCM was selected as ERCOT's new market design in 2023 by the PUC, then under the chairmanship of Peter Lake. In February 2024, ERCOT and E3 filed a strawman design with 37 parameter decisions, leading to months of workshops and stakeholder discussion.

The mechanism would reward thermal generators with credits based on their performance during a determined number of scarcity hours. Those credits must be bought by load-serving entities, based on their load during those same hours, or exchanged by LSEs and generators in a voluntary forward market. (See *Texas PUC Submits Reliability Plan to Legislature*.)

Two New TEF Applications

The commission approved two more applications for *Texas Energy Fund* (TEF) loans *identified by staff* and advanced them for due diligence (*56896*).

The NRG Energy and WattBridge Energy IPP Holdings projects represent 1,231 MW of potential new generation and replace an apparently fraudulent project submitted by a company with suspect backing that left a nearly 1,300-MW hole in the fund's portfolio. (See *Texas PUC Rejects Possible 'Fraudulent' Loan Application*.)

The additions bump the TEF's In-ERCOT Generation Loan Program portfolio to 18

ERCOT News

applications offering 9.72 GW of potential new generation. They are seeking $5.34 billion in loaned funds. The Texas legislature has allocated $5 billion to the fund.

The *NRG application* is for a new 721-MW natural gas combined cycle unit at its Cedar Bayou plant near Houston. WattBridge *submitted applications* for four projects totaling 1,600 MW. The company uses 48-MW aeroderivative gas turbines.

The TEF was established by state law and voters in 2023 and offers a low-interest (3%) loan and grant program of up to $7.2 billion for dispatchable, primarily thermal, generation. The fund has four separate programs.

Entergy Resiliency Plan Approved

The commission approved Entergy Texas's "Future Ready" *resiliency plan*, a $335 million, three-year proposal consisting of six resiliency measures that begins next year. Each of the measures is intended to prevent, withstand, mitigate or more promptly recover from the risks posed by one or more specified and defined resiliency events to the utility's transmission or distribution system, Entergy said (*56735*).

Entergy hopes to gain PUC approval of $137 million in projects and to seek conditional approval and include $198 million of additional resiliency projects under the TEF's Outside ERCOT Grant Program. Once it's up and running, the program will award grants for infrastructure modernization, weatherization, reliability and resiliency improvements, and vegetation management.

Entergy also is making a second attempt to secure funds from the U.S. Department of Energy's *Grid Resilience and Innovation Partnerships* program to help with its $107.5 million *infrastructure and grid hardening project* in Port Arthur, Texas. The utility's staff told commissioners they are negotiating with the DOE over a $54 million cost-sharing portion of the plan.

An administrative law judge found a settlement reached between Entergy and PUC staff, the Office of Public Utility Counsel and several consumer groups to be in the public interest.

Glotfelty Closes His Last Meeting

Commissioner Jimmy Glotfelty was given the honor of adjourning the open meeting with a ceremonial gavel honoring his 3½-year tenure on the PUC. It was the commissioner's last meeting after announcing Dec. 4 he would step down. (See *Texas PUC's Glotfelty to Resign from Commission*.)

"This has been a wonderful opportunity, serving with you all and serving with the prior commissioners that have come before us," Glotfelty said. "It has been a proud time in my career. It's my hope that we've done it with honor and that we have done it knowing the gravity of our decisions can mean life and death."

"Thank you for all the work you did on my nuclear project. I appreciate you getting it started for me so I can take it over," joked Gleeson, who will pick up Glotfelty's role leading the PUC's advanced nuclear reactor effort. "We're definitely going to miss you. You're leaving a big hole up at this dais with you walking out."

Glotfelty then gaveled the meeting to a close. "I announce us adjourned," he said.

PUC Hires External Affairs Chief

Gleeson opened the meeting by announcing Lucy Nashed's hiring as the agency's new chief of external affairs. She will oversee the PUC's external-facing divisions (communications, government relations, public engagement, utility outreach and consumer protection) and their strategy and day-to-day operations.

Nashed previously directed communications for *Texans for Lawsuit Reform* over eight years. The organization advocates for a "fair and efficient" legal system and against "abusive and unnecessary litigation."

The commissioners also passed a motion requesting the Office of the Attorney General to intervene in Rio Grande Electric Cooperative's petition from a declaratory order from FERC. The cooperative requests FERC not to assert jurisdiction over public utilities not presently under the Federal Power Act after RGEC disconnected from WECC and interconnected with ERCOT (*EL25-23*).

The cooperative said that while some of its distribution lines served by its WECC transmission facilities cross state lines to serve end-users in New Mexico, the energy is carried by RGEC's non-jurisdictional distribution facilities and would not constitute wholesale transmission in interstate commerce. ■

— Tom Kleckner

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ISO-NE News

NEPOOL Markets Committee Briefs

By Jon Lamson

ISO-NE continued work with stakeholders on its capacity auction reform (CAR) project at the NEPOOL Markets Committee (MC) meeting Dec. 10, *previewing* 2025 discussions on the transition to a prompt capacity auction.

ISO-NE plans to kick off detailed discussions on a prompt capacity auction and associated resource retirement reforms in early 2025. The prompt changes are intended to reduce the time between capacity auctions and capacity commitment periods from more than three years to just a few months.

The RTO intends to file these changes with FERC in late 2025 before starting work on a second filing focused on accreditation reforms and developing a seasonal capacity market. The filings are intended to be complementary, but the initial filing must be able to stand on its own. ISO-NE intends for both filings to take effect for the 2028/29 CCP (CCP19).

For resource retirements, the move to a prompt auction would require the RTO to "decouple the deactivation process" from the capacity auction bidding process, Chris Geissler of ISO-NE said. While resources currently indicate their plans to retire through the forward capacity market, a prompt market would not provide enough time for ISO-NE to respond to these retirements before the CCP.

When decoupled from the capacity market, "deactivation notices would be due less than four years in advance, but well before the auction is run to allow the ISO time to assess whether the deactivation raises any concerns with respect to local transmission security or market power," Geissler said.

The move to a prompt market also would require ISO-NE to evaluate how it treats resource entry. While the current forward capacity market allows resources that are not yet in operation to bid into the market, this has caused some "ghost capacity" issues, in which resources that fail to come online in time for the CCP affect the clearing price.

"Under a prompt auction, where the auction is run much closer to the delivery period, new resource qualification can be substantially simplified," Geissler said. "The shorter auction activity timeline and new resource qualification rules may alleviate the concerns about phantom entry and delayed operation that exist today."

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

IMM Report

Also at the MC, the ISO-NE Internal Market Monitor (IMM) presented its *markets report* for summer 2024, which found that "energy market outcomes were competitive, energy supply mitigation was infrequent and there was no evidence of impactful capacity withholding overall."

The overall wholesale market value increased by about 21% over the 2023 value, Kathryn Lynch of the IMM said. While gas prices were down by about 21%, this was offset by higher loads and resource retirements, Lynch noted.

Real-time reserve payments also increased to nearly $24 million — compared to about $4 million in 2023 — because of longer capacity scarcity events, Lynch said.

The system experienced two capacity scarcity conditions over the summer, which were driven by generator outages and high loads, Lynch said. Oil resources took a significant financial hit during these events, receiving more than $18 million in net pay-for-performance (PFP) charges across both events. Non-combined-cycle dual-fuel resources received more than $12 million in net PFP charges, and coal resources received nearly $4 million in charges.

In contrast, imports performed extremely well during these events, earning nearly $29 million in net PFP credits, while nuclear resources and combined-cycle dual-fuel resources each earned more than $3 million in net PFP credits.

MC Votes

Prior to the meeting, NEPOOL announced the MC has elected Ben Griffiths of LS Power as vice chair for 2025.

The committee voted to approve market rule *revisions* clarifying the metering of storage as transmission-only assets. The MC also referred to the Generation Information System (GIS) Working Group a *proposal* from the Vermont Public Utility Commission to make changes to the GIS system "to reflect the addition of a new tier of resources to the Vermont Renewable Energy Standard." ■

ISO-NE News

Overheard at Raab Electricity Restructuring Roundtable

BOSTON — Energy experts from across the Northeast gathered for Raab Associates' New England Electricity Restructuring Roundtable on Dec. 13 for a preview of some of the key issues that will dominate policy discussions in the coming year.

While 2024 brought notable success on state-level climate policy in Massachusetts, the new year brings significant uncertainty regarding whether the change in federal administration will slow the momentum of the clean energy transition in the region. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

Prior to the passage of a major omnibus *climate bill* in November, "the first thing on the list of challenges was siting and permitting," said Rebecca Tepper, secretary of the Massachusetts Executive Office of Energy and Environmental Affairs.

The new climate law creates a streamlined siting and permitting process for clean energy infrastructure, capping the state's review of permitting applications to 15 months for large projects. Tepper said collaboration between a wide range of stakeholders through the state's Commission on Energy Infrastructure Siting and Permitting was essential to passing the bill with widespread support.

Looking forward, Tepper said the state's "big challenge for [2025] is interconnection; you're going to see us really focusing on that next year."

Tepper also highlighted the possibility of another offshore wind procurement in 2025 and said the state is exploring the potential of new interregional transmission links with New York, PJM or Québec. "We see a lot of opportunity for further hydro coming from Canada," she said.

Serge Abergel, COO of Hydro-Québec Energy Services, said increased transmission capacity between New England and Québec could help speed up decarbonization and reduce the need to overbuild renewables as the Northeastern U.S. achieves a highly decarbonized system. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

He said Hydro-Québec's modeling indicates that an additional export-neutral transmission line between the regions could provide major benefits by 2040. A new line "could reduce the length of a major outage by about two days, and it could save [New England] $2 [billion] to $3 billion over those two days," Abergel said.

From left: Marianne Perben, ISO-NE; Mason Emnett, Constellation Energy; Serge Abergel, Hydro-Québec Energy Services; Secretary Rebecca Tepper, Massachusetts Executive Office of Energy and Environmental Affairs; and moderator Janet Gail Besser | © *RTO Insider LLC*

Why This Matters

Massachusetts Energy Secretary Rebecca Tepper signaled a major push for state-level interconnection improvements in 2025.

Recent drought conditions have caused the company to reduce exports over the spot market to New England, causing some observers to question the reliability of Québec supply in the future and whether the benefits of new transmission capacity would justify the costs.

While ISO-NE's exports to Québec have increased during the drought, imports continue to play a key reliability role on the grid: They earned $29 million in Pay-for-Performance credits during two capacity scarcity events this summer, far more than any other resource class. (See *NEPOOL Markets Committee Briefs: Dec. 10, 2024*.)

Abergel said there is uncertainty over the degree that climate change has influenced the current drought and said the conditions are "on par with the worst cycle we've seen in the past."

"Our firm commitments are always met, but our spot market sales fluctuate," he said, adding that the New England Clean Energy Connect transmission project — which includes a 20-year contract for Québec to send baseload power to New England — should be in service in December 2025.

Hydro-Québec's energy supply should also receive a major boost from a *new agreement* between Québec and Newfoundland and Labrador, which was announced the day before the roundtable. The agreement would increase the price Québec pays for power from the Churchill Falls hydroelectric generating station in Labrador while paving the way for a significant increase in generation capacity.

FERC Preview

Former FERC Chair Richard Glick, now a principal at GQS New Energy Strategies, previewed what the new year could bring for the commission.

As states work to decarbonize their power

ISO-NE News

supply, Glick said the incoming Trump administration "will have an impact, but maybe not as much of an impact as some fear," adding that he is "still very bullish on what's going on in the clean energy side."

He also praised FERC's work on Order 1920-A, calling it "a very helpful order" that should increase the likelihood of successful transmission projects.

Regarding Order 2023, which overhauled FERC's interconnection rules, Glick said the commission likely "didn't go far enough" and noted that it has taken "a really long time to act on the compliance filings." (See *New England Clean Energy Developers Struggle with Order 2023 Uncertainty*.)

Under a Republican-led commission, grid operators may be afforded greater flexibility on both orders, Glick said. He added that, under the Trump administration, FERC could look more favorably at pipeline expansion projects and proposals to allow fossil generators to skip ahead in the interconnection queue for reliability purposes.

Electric Vehicle Outlook

The roundtable also featured a panel focused on transportation decarbonization, with speakers discussing the growth of the U.S. electric vehicle industry and the potential of managed charging.

Roger Kranenburg, vice president of energy strategy and policy for Eversource Energy, said he remains optimistic about the overall upward trend of EV sales despite recent growth challenges and a less favorable stance from the incoming administration. He emphasized the major role that fleet-level electrification will play in transportation decarbonization.

"Fleets are coming, and they're going to transition faster" than individual consumers, Kranenburg said. "It's all an economic decision."

Chris Rauscher, head of grid services and virtual power plants at Sunrun, highlighted the potential of EVs to help eliminate peak demand costs and emissions.

There currently is "way more capacity in electric vehicles than there is in stationary storage in the U.S.," Rauscher said, adding that, when modeling 200,000 bidirectional EVs on the New England power system, just 30% of the vehicles' battery capacity would eliminate the need for oil peakers on a winter day. ■

— Jon Lamson

Former FERC Chair Richard Glick (left) and Jonathan Raab, Raab Associates | © *RTO Insider LLC*

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MISO News

MISO Board Endorses $21.8B Long-range Transmission Plan

By Amanda Durish Cook

THE WOODLANDS, Texas — The MISO Board of Directors has approved a landmark, 24-project, mostly 765-kV collection of transmission lines and facilities for the RTO's Midwest region at a cost of $21.8 billion.

The board voted unanimously in favor of the RTO's second-ever Long-Range Transmission Planning (LRTP) portfolio during its Dec. 12 meeting.

MISO estimates the benefit-to-cost ratio of the portfolio to be between 1.8:1 and 3.5:1 over the first 20 service years of the projects, owing to superior reliability, production costs, avoided construction of new capacity and environmental benefits. The grid operator's planners emphasized that the benefit values are intentionally on the conservative side. (See *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.)

MISO Chief Strategy Officer Andre Porter said the portfolio will allow for "additionally optimized buildout" of generation desperately needed on the system.

Speaking for MISO's transmission owners, ITC Holdings' Brian Drumm said the second LRTP represents the "single largest transmission portfolio in the history of the United States." He told the board that the "765-kV regional backbone will significantly increase the MISO Midwest's ability to facilitate generation fleet transition, accommodate load growth, and successfully withstand increasingly frequent and severe weather events."

Sustainable FERC Project Senior Advocate Natalie McIntire called the portfolio "historic" and said the lines will further states' clean energy goals. "These projects will serve customers for more than 40 years. We're all going to benefit from them," McIntire said.

John Liskey, general counsel for the Citizens Utility Board of Michigan, said he spoke on behalf of MISO's consumers advocates when he applauded the RTO's development of the portfolio.

Two days before the vote, the governors of Illinois, Michigan and Minnesota wrote to applaud MISO for developing the portfolio and urged the board to accept it.

"For years, we have advocated for MISO to take a long-term view in resource planning and to engage states and diverse stakeholders on the development of a robust and long-range transmission system that ensures cost-effective, reliable power for our residents and businesses with the flexibility to accommodate a diverse resource mix," wrote Minnesota Gov. Tim Walz, Michigan Gov. Gretchen Whitmer and Illinois Gov. JB Pritzker. "This work is more important than ever as the region works to grow our economies and prepare for load growth from data centers, advanced manufacturing, electric vehicles and more."

The MISO Board of Directors meets Dec. 12 in The Woodlands, Texas, to approve the LRTP portfolio. | *© RTO Insider LLC*

Why This Matters

The $21.8 billion transmission portfolio is MISO's — and the nation's — largest single transmission investment. It will position the MISO Midwest territory to bring more clean energy online, meet load growth and ride out increasing weather extremes.

Caveats and Criticism

"This is a monumental moment in our shared history," said Yvonne Cappel-Vickery of the Alliance for Affordable Energy, a Louisiana consumer advocacy nonprofit. But she also said MISO South desperately needs comparable planning, which is years away by MISO's schedule. The longer MISO waits to propose transmission in the South, which she said contains MISO's poorest regions, the longer ratepayers are deprived of the economic benefits that transmission brings, she said.

North Dakota Public Service Commissioner — and U.S. Representative-elect — Julie Fedorchak said she did not agree with MISO and stakeholders shutting out the Independent Market Monitor's criticisms of the portfolio and putting "the IMM in a box on what he can and cannot comment on."

Monitor David Patton had argued the LRTP portfolio is too expensive and its benefits far-fetched. Patton has said repeatedly that the capacity expansion MISO envisions through the early 2040s and the portfolio it is based on is "extremely unrealistic." Patton insists his analysis shows the portfolio's benefits fall well short of covering costs.

Several stakeholders countered that the Monitor should concentrate on markets and that his opinions on transmission planning are an overreach.

MISO argues it based its outlook on the resource plans its members have communicated and that it is not its place as an RTO to test the LRTP portfolio against an imagined, alternative resource expansion.

MISO News

Prior to approval, the board had been mum in public meetings as to its level of support for the portfolio or whether they viewed the Monitor's criticisms of the portfolio's estimated value as legitimate.

The Union of Concerned Scientists' Sam Gomberg asked MISO to formally define the Monitor's role, including the boundaries of his role in transmission planning. Gomberg said if MISO decides to allow the Monitor to influence its transmission planning process, it should hold it to a "reasonable standard of analytic transparency."

ACORE Webinar

Hours after board approval of the massive portfolio, the American Council on Renewable Energy hosted a webinar called "Midwest Does it Best."

MISO Director of Cost Allocation and Competitive Transmission Jeremiah Doner said the 765-kV lines are a "major leap forward." MISO has very few 765-kV lines today, he said, and the expansion will position MISO to handle load growth, fleet transition and more commonplace weather extremes.

"We saw we really needed to make that step to 765 kV," Doner. He added states' resource planning took center stage in MISO's transmission planning, and the lines were not charted with any political objectives in mind.

Clean Grid Alliance Executive Director Beth Soholt said the approval means members can "build the grid that's going to incorporate what the states are going to do."

Tyler Huebner, of Google's Energy Market Development Team, said the investment is "a big down payment" for companies, like Google, with ambitious climate goals.

Indiana ROFR Reversal Complicates Project Assignment

"For the first time in 18 months, I don't have a map of projects to share with you; I don't have a study process to discuss. We've come a long way," Vice President of System Planning Aubrey Johnson told the board's System Planning Committee on Dec. 10.

Johnson said about $7 billion of the $21.8 billion portfolio will be open to competitive bidding. However, the figure does not account for the fresh court injunction against Indiana's right of first refusal law.

U.S. District Court for Southern Indiana Chief Judge Tanya Walton Pratt blocked the law benefiting incumbent utilities that had been in effect for about a year and a half. Chief Judge Tonya Walton Pratt on Dec. 6 issued a preliminary injunction against Indiana's House Enrolled Act 1420, which allowed incumbents first crack at the opportunity to build transmission projects planned by MISO. (See *New Law Expands Indiana ROFR Law for Transmission Buildout*.)

MISO planning leads Aubrey Johnson and Laura Rauch spearheaded the LRTP effort. | © *RTO Insider LLC*

Competitive transmission developer LS Power sued the Indiana Utility Regulatory Commission, arguing the state violated the U.S. Constitution's Commerce Clause by treating in-state developers differently out-of-state developers.

Pratt agreed with that argument.

"HEA 1420, though not a complete ban on out-of-state transmission owners, erects a barrier to the interstate electric transmission market by limiting who can compete for new construction projects in Indiana," Pratt wrote. "The right of first refusal in favor of Indiana incumbents runs contrary to the Supreme Court's admonition that 'states cannot require an out-of-state firm to become a resident in order to compete on equal terms.'"

Johnson said the uncertainty over whether LRTP projects in Indiana will be open to competitive bidding did not affect the board's ability to approve the portfolio. MISO Counsel Jacob Krause later added that the RTO's legal team is analyzing the court ruling to determine who can build LRTP projects in Indiana. He agreed the temporary injunction did not impede the board's ability to vote on the package.

Doner said MISO is indifferent as to which companies construct the LRTP lines but wants them finished in a timely manner.

No LRTP Planning in 2025

MISO board members will evaluate a third major transmission portfolio at the end of next year because the RTO announced it will take a break from long-range planning over 2025 to revamp its three, 20-year future scenarios it uses to evaluate system needs. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.)

"The futures have already gone stale," Drumm said during the ACORE panel.

When MISO returns to LRTP work in 2026, the next portfolio again will prescribe transmission for the Midwest, leaving the South's long-range needs unaddressed for the next few years.

The LRTP this year overshadowed MISO's prescribed $6.7 billion of traditional spending as part of its annual Transmission Expansion Plan, which also was approved (See *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.) The board also greenlit the $1.65 billion Joint Targeted Interconnection Queue transmission portfolio developed in partnership with SPP.

In total, the board sanctioned more than $30 billion in transmission investment. ■

MISO News

MISO Estimates Solar Fleet will be 12 GW by Winter's End

By Amanda Durish Cook

THE WOODLANDS, Texas — MISO expects its in-service solar capacity to grow to 12 GW by the end of winter, a 50% increase over its existing fleet.

Speaking during a meeting of the MISO Board of Directors' Markets Committee on Dec. 10, Executive Director of Market Operations JT Smith said MISO anticipates developers will finish about 4 GW of new solar generation before March hits. "That's three times more than what we had last winter," Smith said.

The RTO's latest solar peak of 8 GW occurred Oct. 16.

Smith said MISO's solar fleet even now is significant enough that the grid operator notices diurnal output patterns, with a steeper ramp requirement in the evenings.

He said members in the footprint are set to add an additional 4 to 7 GW of solar generation by the end of 2025 as renewable developers bring some of their approved solar farms online.

"Next winter, we might be talking about 20 GW of solar," Smith said.

Carrie Milton, of MISO's Independent Market Monitor, told board members that over the upcoming winter, the RTO could experience ramping needs as high as 12 GW during the period of 3-7 p.m. She said MISO must work diligently to manage more "extreme" ramping needs.

Milton said over two instances in the fall, MISO experienced shortage intervals where prices spiked to the $3,500/MWh value of lost load (VOLL). She said in one case, generation was powering down faster than load was dropping in the evening and in another, renewable energy output fell faster than forecasted.

Milton told MISO and its board that "improved ramp management will be key," especially as the RTO filed to increase its VOLL to a $10,000/MWh cap. "That's going to be much more impactful," Milton said of the higher rates.

From left: IMM David Patton, IMM Carrie Milton, MISO's Zak Joundi and MISO's JT Smith | © *RTO Insider LLC*

Monitor David Patton advised MISO to expect an influx of battery storage to enter its interconnection queue soon. "Batteries are going to be increasingly economic in this environment," he said.

MISO leadership reiterated to its board that though winter on the whole shouldn't cause strife in the operations room, it's preparing for at least a few challenging days.

MISO is entering winter with a 131-GW planning reserve margin requirement but a 100-GW probable demand and a 107-GW high-demand scenario. (See *MISO Says Comfortable Wintertime Margins Likely in Store*.) The RTO isn't issuing serious warnings over the upcoming cold weather but isn't ruling out a widespread freeze or snowstorm.

"We can have a mild winter — and we have the past three to five years — but you can have those days, three sigma, four sigma days that can cause tremendous damage," MISO CEO John Bear warned.

"Each year, it's almost predictable that something is going to happen," Milton agreed. But Milton said even in the IMM's analysis of worst-case winter conditions, MISO still should experience a 2% margin.

Smith noted that MISO's past few winter storms with precarious operations have occurred over long holiday weekends. The February 2021 winter storm occurred over Washington's Birthday, and the December 2022 winter storm occurred over Christmas.

Smith joked that he hoped MISO's next bout of serious winter weather shows up "Tuesday on a non-holiday weekend" so members can contract adequate natural gas ahead of time.

Otherwise, MISO exited a "wholly unremarkable" fall, Smith said, with a 106-GW peak occurring Sept. 19 and short of its projected 108-GW peak.

Milton noted that over the fall, congestion costs were dramatically lower in the northwest portion of the footprint as drought conditions in Manitoba eased and MISO began receiving power exports again instead of importing to the province. She also said that SPP further improved MISO's congestion position by implementing a remedial action scheme for the Charlie Creek flowgate in North Dakota. Milton said the scheme, which involves SPP cutting load in their footprint to avoid exacerbating congestion, reduced costs of the constraint by 95%.

The Charlie Creek flowgate has been a contentious issue between MISO and SPP since 2023, when a cryptomining facility began operations in an SPP load pocket and exacerbated congestion. (See *MISO Argues to FERC for 2nd Look at Crypto-stressed Flowgate Management*.) ■

Why This Matters

MISO said it's noticing diurnal output dips associated with its growing solar fleet. The Independent Market Monitor told the RTO to be aware of more pronounced ramping needs.

MISO News

Voltus Seeks Ability to Replace Customers in MISO DR Aggregations

By James Downing

Voltus filed a complaint with FERC against MISO on Dec. 11 asking it to require the RTO to allow the replacement of customers who sign up as load-modifying resources (LMRs) in the Planning Reserve Auctions (*EL25-37*).

Aggregators like Voltus can sign up customers to provide demand response and clear that capability in the capacity market, but then those customers could go out of business or otherwise be unable to supply the capacity when needed, the company told the commission. When that happens, aggregators need to be able to replace the resource with another customer facility to provide the contracted DR.

"Generators that become unavailable can be replaced, and there is no reason to treat LMRs differently," Voltus said.

Voltus argued that MISO's tariff as written does not treat LMRs differently, and it expressly permits such replacements. MISO used to interpret it that way until a tariff change in 2022.

"An apparently unintended consequence of that change is that MISO believes the tariff no longer authorizes MISO to permit an aggregator to replace an LMR that cleared the capacity market but is no longer available, even though a similarly situated generator may be replaced," Voltus said. "A generator may even use a demand response resource as a replacement resource, but in the circumstance where a demand response resource becomes unavailable, MISO does not allow for its replacement."

The 2022 change requires that generators be replaced after a prolonged outage, but Voltus said its "plain language" does not implicate replacing customers supplying DR.

"There is not any discussion of such disparate treatment sufficient to provide notice to market participants," Voltus said. "In short, if the 2022 tariff amendment had the effect attributed by MISO, it appears to have been inadvertent. Because the plain language of the amendment leaves plenty of room for an interpretation that no such change occurred, the commission should confirm that no such change did occur."

If FERC finds MISO's interpretation to be correct, then the commission should order a change in wording to reinstate LMRs' ability to be replaced because the current practice wrongfully omits useful resources from the reliability equation, the company argued.

"MISO deems LMRs useful enough to replace generation," Voltus said. "There can be no good reason why such a useful resource should not be afforded the right to be replaced itself."

PRAs are run in April for delivery years that start June 1, and LMRs can bid into the auctions as zonal resource credits (ZRCs).

The new rule was meant to require that generators that are offline for more than 31 days be replaced, which MISO felt was necessary as the PRA shifted to a seasonal construct. After the amendment went into effect, MISO cited a sentence from it as the basis for its interpretation that LMRs could not be replaced: "A planning resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, catastrophic generator outage, or full or partial generator planned outages that may exceed 31 days in the season."

MISO's Carmel, Ind., headquarters | © *RTO Insider LLC*

While the reasoning for replacing resources is focused on generators, Voltus said the "plain meaning" of the terms "retirement" and "suspension" should be applied to the customer sites backing LMRs. DR is one of the last resources MISO operators use to prevent load shedding, so the more of it available means they can better respond to emergency conditions, it argued. ■

MISO News

MISO Tells Board RA Fast Lane in Interconnection Queue is a Must

By Amanda Durish Cook

THE WOODLANDS, Texas — MISO told its Board of Directors it's essential to draft an interconnection queue express lane for generators that resolves resource adequacy risks and has stamps of approval from regulators.

At a Dec. 10 System Planning Committee, MISO's Scott Wright told directors that though MISO runs a "good" queue process, it's "not enough to get us where we're going." He said MISO needs to debut a priority study lane for critical generation projects. (See *MISO Outlines Plan on Fast-track Queue for Resource Adequacy*.)

Because of capacity sufficiency needs, Wright said MISO can't afford to wait for the three to four years projects spend in the normal queue, with construction times added to that.

"This is to fill a gap that's very real to address until we can get the queue down to a one-year process. This is temporary. This is not an ongoing way of doing business," he said.

MISO's queue clocks in at 312 GW across more than 1,700 projects.

"What we have is a massive volume deluge, and it's resulted in large backlogs," Wright said. "But we need resources now."

To meet its upcoming resource adequacy needs, MISO estimates members need to bring at least 17 GW of nameplate capacity online annually, or about 7 GW to 8 GW of accredited capacity. According to MISO records, the footprint brought about 3.4 GW in accredited capacity online in 2024.

Clean energy groups argue that a dedicated express lane could create equity concerns for projects in the regular queue. They've said one-off, accelerated studies for individual projects could result in the RA projects paying far less in network upgrades than their counterpart projects in the regular queue, where major network upgrade costs are spread across groups of projects in study clusters.

Scott Wright, MISO | © RTO Insider LLC

The Sustainable FERC Project has asked MISO to consider making the expedited process a one-time occurrence with a single round of project applications to address states' near-term resource adequacy risks.

Clean Grid Alliance's David Sapper said MISO should rethink filing for the RA fast lane in a "few hurried months." He told MISO board members at their Dec. 12 meeting that the new process would amount to an "assault on fundamental transmission open-access policies."

Sapper said MISO's specialized study process would create "undue competitive advantage for projects that are allowed to skip the queue and use up existing transmission capabilities while queued projects are held back, thereby degrading their economics."

"As a table mate at dinner last night noted — to nobody's surprise — once investors know there is a way to skip the queue, they won't want that to go away," he said.

MISO staff say if some of the unfinished, delayed resources with signed generator interconnection would come online, MISO would worry less about creating an exclusive avenue in its queue.

The RTO has amassed 57 GW (or approximately 27 GW in accredited capacity) in planned resources that have made it through the queue, have signed interconnection agreements but remain half-finished due to supply chain hurdles or other holdups.

Wright also said the sheer volume of projects is "eating away at the effectiveness" of the queue process enough that MISO needs to apply its proposed annual megawatt queue cap on the regular queue. That cap plan is pending before FERC.

"What we're doing today isn't working for tomorrow," MISO's Aubrey Johnson said at a Dec. 6 special workshop to discuss the expedited process.

While the grid operator discusses its RA needs, it's decided to skip a 2024 cycle of its interconnection queue while it attempts to automate and speed up studies. (See *MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup*.)

MISO also appears to be getting at least some of its wish for postponements of generation retirements, which leadership has suggested as a temporary means of maintaining resource adequacy.

Alliant Energy *announced* earlier in December that its coal-fired Columbia Energy Center will operate through 2029 while it and co-owners Madison Gas and Electric and Wisconsin Public Service explore converting one of the units to natural gas to bolster reliability. The coal plant was set to close at the end of 2024, which later was pushed back to 2026.

Missouri utilities say they plan to build new capacity after last year's Zone 5 shortfall in the capacity auction, where utilities were exposed to cost of new entry capacity prices at $719.81/MW-day for fall 2024 and spring 2025. Some indicated they would take advantage of MISO's proposed, fast-track queue process for necessary generation projects.

Others in the MISO footprint protest the natural gas plant plans that are cropping up as the cure for apprehension over resource adequacy.

Earlier in December, the Sierra Club and Clean Wisconsin *petitioned* the Wisconsin Supreme Court to hear their case challenging Wisconsin regulators' approval of certificate of public necessity for the 625-MW Nemadji Trail Energy Center (NTEC). They argue that the Wisconsin Public Service Commission didn't adequately weigh the environmental impacts of the plant when they approved it. (See *City Council Vote Stalls Planned Wisconsin Gas-fired Plant*.) ■

Why This Matters

MISO plans to continue crafting a dedicated expedited study process for projects that further resource adequacy through early 2025. RTO staff have work ahead of them to convince clean energy groups that the expedited process is a good idea.

MISO News

MISO Decides Against Revising Guiding Principles

THE WOODLANDS, Texas — MISO said it will leave the 10-year-old guiding principles for its market design untouched after it conducted a check-in with stakeholders to gauge whether they are still valid in a rapidly changing industry.

Speaking Dec. 10 at the meeting of the MISO Board of Directors' Markets Committee, Zak Joundi, executive director of markets innovation and strategy, said the RTO received a "relatively small amount of written feedback" after soliciting recommended changes and updates at stakeholder committee meetings. (See *Changing System Drives MISO to Scrutinize Guiding Market Principles*.)

Although a few stakeholders made suggestions about adding nods to resilience or being more prescriptive about resource adequacy, Joundi said the community remains generally supportive of the principles a decade later.

"We feel like this truly covers the whole gamut," he said.

MISO's five *guiding principles* include standing up an "economically efficient" wholesale market system, fostering nondiscriminatory market participation, maintaining transparent market pricing, facilitating efficient operational and investment decisions among market participants, and aligning market requirements with reliability requirements.

In public meetings, some stakeholders have said the principles still seem to make a lot of sense even considering the transformed landscape.

However, at the Market Subcommittee's meeting in October, the Clean Grid Alliance's David Sapper suggested MISO consider adding an insertion encouraging coordination and collaboration among members, regulators and governments to maintain resource adequacy. Sapper also condemned the suggestion that members and states stall carbon-reduction goals for the sake of reliability, made by MISO's Todd Ramey the previous month. (See "More Supply Alarms," *MISO Board Week Covers Supply Worry, SoCal Utility Exec Addition, $400M Budget*.) ■

— Amanda Durish Cook

| *Shutterstock*

MISO News

Exiting MISO President Proud of Tx Trailblazing, Says Load Growth Doable

By Amanda Durish Cook

Reflecting on his more than two decades at MISO, President Clair Moeller doesn't hesitate to say that helping to normalize transmission investment is the most pivotal contribution of his career.

Moeller said MISO was able to convey to members that planning should "maximize value for consumers rather than minimizing investments." In a press call to reflect on his tenure and the state of the industry as he exits, Moeller said around the mid-2000s and early 2010s, MISO began doing an enviable job of showing the value of potential transmission through analyzing production costs and other benefits. That work culminated in MISO's approximately $6.6 billion Multi-Value Portfolio in 2011, its first comprehensive long-range transmission planning.

Moeller leaves MISO at the end of 2024, as the RTO's Board of Directors approved a $21.8 billion long-range transmission plan (LRTP) portfolio, a sign of how far MISO has come on transmission planning in the Midwest. (See *Longtime MISO President and COO Moeller to Retire*.) MISO has vowed to plan more portfolios.

"It's value engineering rather than cost engineering," Moeller said. "That's why we at MISO are accomplishing these transmission investments where other regions are struggling."

The best advertisement for long-range transmission is to "get steel in the ground," he said. After that, Moeller said the transmission can speak for itself on its value.

"You can see that as people gain confidence in the answer, it's easier to repeat," he said.

Moeller acknowledged long-range transmission takes time, pointing to Cardinal-Hickory Creek's completion date 13 years after it was approved in 2011. He also said the regulatory process and supply chain are "sequential," lengthening timelines. He said it's natural that developers "wait for permission before they order things."

Moeller said MISO's LRTP efforts are a combination of members pushing MISO to do more intensive planning and the RTO pulling states along. He said the LRTP represents MISO and members walking "away from the cartoon that says minimizing investment is the way to keep people's bills down."

Why This Matters

Long-range transmission takes time, and Moeller points out that data center developers are sending mixed messages where they pay lip service to clean energy goals but turn to combustion turbines today to snap up a 24/7 source of electricity.

More investment appears certain as load growth climbs around the nation, spurred by the rise of data centers.

"The speed to market for the AI stuff, I think, surprised everybody," Moeller said.

Moeller said he's confident that 10 years down the road, enough generation will exist to serve load, but he predicted "turbulence in the short run."

"By 10 years, we'll probably be OK," he said.

Moeller said by that time, MISO's control room should have new uncertainty tools fashioned out of necessity because of the volatility of renewable energy. He said improved weather forecasting and maintaining adequate reserves to cover severe down-ramping will be essential. MISO will have to "tune" its reserves on hand to the risk of the day, where a several-gigawatt, sudden down-ramp in wind might be commonplace, he said.

"The level of sophistication has to improve by an order of magnitude," he said, adding that MISO will have to shed the "deterministic model embedded in the industry's history."

Moeller said reworking how to measure resource adequacy isn't new, as MISO has been trying to better quantify risk for a decade.

"These aren't new problems. The data centers are a new wrinkle," he said. But he conceded that 20 years ago, "the math was easy" because all generation looked the same and the summer peak was the lone worry.

MISO President Clair Moeller | *© RTO Insider LLC*

MISO News

"I'm quite confident we'll get through it," Moeller said, asking that the industry allow engineers the space to work and figure things out.

Moeller said the challenge today between exploding load growth and bringing new generation and transmission online is one of timing, with load moving at a faster pace. He said although data center load always has been on the grid, the 80-MW centers of yesteryear are being supplanted by minimum 800-MW facilities.

He said one prospective data center in MISO would add 2,500 MW of load, rivaling Indianapolis' demand.

"You don't build enough resources to serve Indianapolis in 24 months," he said. "If you order a combustion turbine today, it's 60 months out. … Those kinds of collisions are going to complicate our lives for the next … five to eight years."

Moeller said complicating matters, data center developers might negotiate simultaneously with three separate utilities, making load growth appear more prevalent than in reality.

"Everybody signs non-disclosure agreements so they can't say anything, but then there's an announcement," Moeller said, advocating for the industries to calm down the "chaos."

He said MISO must determine the "blips" from the "trends" to see what types of growth are enduring. Moeller said consultants tell MISO that industrial reshoring might be a passing trend while the appetite for data crunching is more durable and long-lasting.

Within 20 years, Moeller predicted the grid will need dispatchable assets to cover shortfalls that can persist for days during still, overcast days. He said it's possible the threat of those tricky days will tack on a few years to achieving clean energy goals, but the emergence of data centers today might be able to help fund combustion turbines that can be relied on as a backup source of emergency power.

"It's that kind of schedule flexibility that can help us get through this," Moeller said.

Yet, Moeller said data center developers are sending mixed messages where they pay lip service to clean energy goals but turn to combustion turbines today to snap up a 24/7 source of electricity.

Moeller said that double-speak is likely to spell only a temporary hiccup for the industry.

He also implied a second Donald Trump administration ultimately might do little to reverse the clean energy movement.

"I think people understand the change has to happen. … The trends are pretty clear on the greening of the fleet," Moeller said. "How fast we're moving changes with administrations, but it doesn't mean we're not going to move."

MISO CEO John Bear praised Moeller for his two decades at the RTO at a Dec. 12 board meeting, He said Moeller accomplished the "unbelievable" feat of getting people to rethink transmission planning to be a value-based endeavor.

"The magic of MISO is that I've never had to live outside my values to work here," were Moeller's parting words at the board meeting. ■

NYISO News

Stakeholders Turn down NYISO Reserve Performance Penalties

By Vincent Gabrielle

The NYISO Business Issues Committee on Dec. 11 tabled an ISO proposal to levy financial penalties against consistently underperforming generators in the reserve market, though it supported a related measure intended to better identify such resources so they can be removed.

The Operating Reserves Performance Penalty proposal, presented to the Installed Capacity Working Group in November, consisted of two components. The BIC declined to recommend that the Management Committee approve assessing the financial penalties, which would require tariff changes and was not well received by members of the ICAPWG. (See *Stakeholders Skeptical of NYISO Performance Penalty Proposal*.)

"We've received robust feedback across multiple meetings, and in the holiday spirit, it makes me feel a bit like a chestnut roasting on an open fire at times," said Nathaniel Gilbraith, NYISO manager of energy market design.

While NYISO believed that the performance penalty proposal was "reasonable and commensurate" with the issue of underperformance, the ISO recognized that stakeholders preferred focusing on disqualification and removal of poor performers, Gilbraith said.

The dollar value of these poor performers ranges between $100 million and $260 million per year, according to the ISO.

The committee did, however, support the second component, which is to establish a rebuttable presumption for resources found to be underperforming. Those resources would be removed from the market unless they can demonstrate that the cause of the poor performance has been fixed. As part of that, NYISO would establish three different metrics for assessing underperformance. The BIC recommended directing the ISO to describe the "consequences for persistent operating reserve market underperformers" as described in the original *proposal*.

If approved by the MC at its meeting Dec. 18, NYISO would develop a new proposal in the first quarter of 2025 to be presented for feedback and aiming for stakeholder approval by the end of next year.

The BIC's motion specified that "the proposed process enhancements will not alter the NYISO's existing tariff authority to remove operating reserves qualification from suppliers that consistently underperform."

It passed with four abstentions and New York City in opposition.

"As I understand it, the removal will occur after some period of time, but during that period of time, these market participants are still going to be compensated for a service they have not provided," said Kevin Lang of Couch White, speaking on behalf of the city. "From the perspective of a consumer, that is unjust and unreasonable."

Lang said that while the city supported removing bad actors, without the financial penalties, the proposal did not fully address the issue.

"We are extremely concerned that the NYISO is not going to pursue what, quite frankly, we thought was the totality of this," he said.

NYISO staff clarified that penalties could be reexamined in 2025. Lang was not satisfied, later saying that this was not a "market design complete" proposal, something he blamed on the rushed process toward the end of the year.

Mark Younger of Hudson Energy Economics agreed.

"I hope we can do this at a high level and get through this alternative motion quickly, and get on with the holiday period," Younger said. "It should be no surprise to anybody that I thought the process we took to get here was a total disaster. … You heard vociferous and, as you tended to note, very consistent and clear concerns that were ignored until about a week ago."

Younger added that he hoped NYISO would have this "all wrapped up by the end of April." ■

Ravenswood Generating Station in Queens, N.Y. | © *RTO Insider LLC*

PJM News

Virginia Legislature Report Tackles How to Meet Surging Demand from Data Centers

By James Downing

Even meeting half of the projected demand from new data centers in Virginia over the next 15 years will prove difficult, according to a report released by a legislative commission.

The Joint Legislative Audit and Review Commission (JLARC) released "*Data Centers in Virginia*" at a hearing Dec. 9. It included recommendations for legislative and other actions the state could take to deal with the rapid growth in electricity demand.

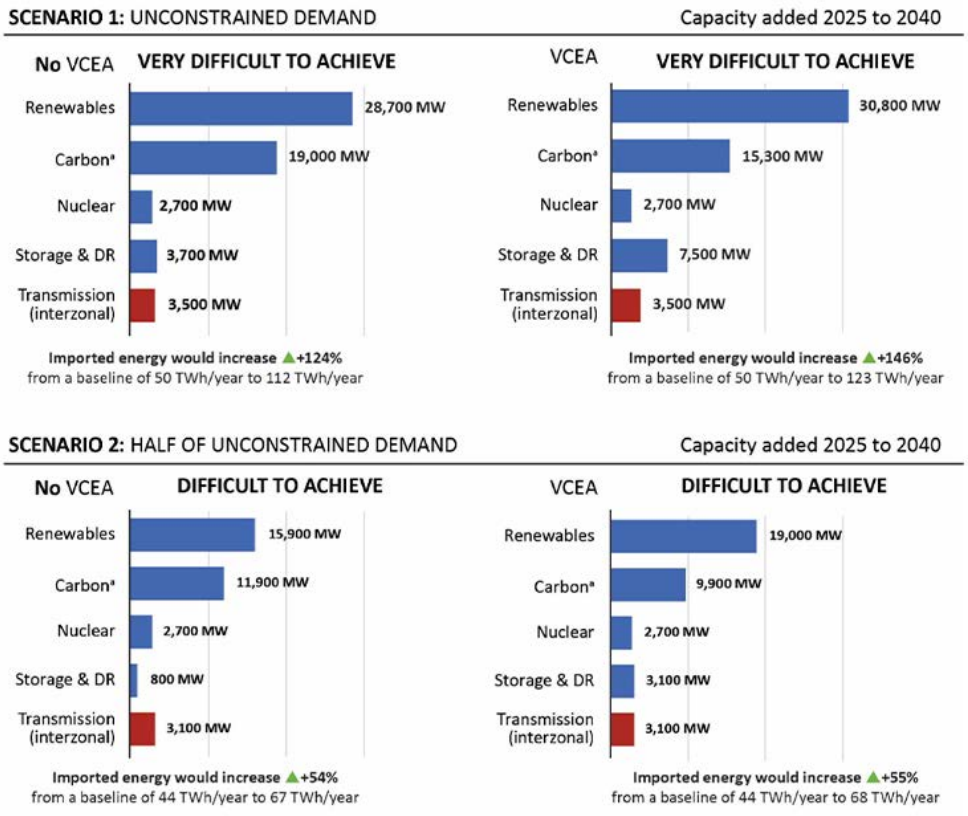
If the sector continues growing at forecast rates, overall demand in the state is expected to double in the next 10 years, according to an independent forecast JLARC paid for, and that's in line with PJM's forecasts.

"A substantial amount of new power generation and transmission infrastructure will be needed in Virginia to meet unconstrained energy demand or even half of unconstrained demand," said the report. Building that infrastructure "will be very difficult to achieve, with or without meeting the Virginia Clean Economy Act (VCEA) requirements."

New solar facilities would have to be added at double the rate they were this year, more offshore wind than has been secured for even potential development would need to be built, and the state would have to add natural gas plants at a rate faster than the busiest period of their construction, which was from 2012 to 2018 in Virginia, the report said.

"Under Scenario 1, meeting unconstrained demand would require adding 150% more in-state generation capacity, 40% more transmission and importing 150% more energy," JLARC staffer Mark Gribbin said at the hearing. "Under Scenario 2, which again is only half the demand materializes, we're still looking at doubling existing generation, 35% more transmission and 55% more imports. In short, either scenario would require a massive increase in energy infrastructure."

The model predicts some of that infrastructure demand would be needed regardless of data center demand, but they are driving most of it, Gribbin added.



A chart from the report showing the amounts of new generation and transmission needed under two different data center growth scenarios and whether the Virginia Clean Economy Act is followed. | *Joint Legislative Audit and Review Commission*

Why This Matters

Northen Virginia is by far the biggest data center market in the world. And though data centers are not driving bill increases for other classes of power customers, that could change with the major infrastructure needs on the horizon.

The modeling also included scenarios where the Virginia Clean Economy Act was followed and those where it was not. All scenarios include some new natural gas power plants ranging from 9,900 to 11,900 MW in the low demand cases, and 15,300 to 19,000 MW in the high demand cases, with the climate law's achievement representing the lower numbers.

"If you look at those, they're not that far apart in terms of what gets built," Gribbin said. "The reason for that is because those VCEA renewable requirements do not apply to the co-ops."

While data centers exist in other parts of the state, they're concentrated in Northern Virginia and in the territories served by co-ops, with JLARC expecting 60% of data centers to be located in co-op territory, he added.

Northern Virginia is the largest data center market in the world, with 13% of all reported global capacity and 25% of capacity in the Americas, the report said. It is nearly twice the size of the second-largest market, Beijing, China, and three times the size of the second-biggest market in this hemisphere, Hillsboro, Ore.

"The region's role in the early stages of the internet's development gave it a head start as a key data center hub," the report said. "In the mid-20th century, early data processing companies contracting with government agencies and high-technology government labs were drawn to the region given its proximity to their federal government customers. The establishment of an internet exchange point in the 1990s further attracted major telecommunications and early internet companies to the region."

With the growth of the internet this century, the capacity in Northern Virginia, and in other parts of the state, especially along Interstate 95, continued to grow because locating data

PJM News

centers closer together cuts "latency," which Gribbin said was a key to the sector's expansion in the area.

"If I have a data center here and a data center across the street, those two data centers can communicate a lot faster," he added. "So, if I am browsing an internet site, or if I'm doing some sort of financial transaction, basically it speeds up how fast they can communicate. And, so, when you start putting more and more data centers and with more and more business customers next to each other, they can communicate very fast."

While hosting the largest concentration of data centers comes with issues, it also benefits the state to the tune of 74,000 jobs, $5.5 billion in labor income and $9.1 billion in GDP every year. Most of those benefits accrue during the construction of data centers.

Data centers also can be a major taxpayer for their communities, though some have offered lower rates to attract them, with the report saying they range from between 1 and 31% of localities' total revenue.

Expanding the facilities away from the I-95 corridor to more economically distressed parts of the state could benefit those communities, but that brings up issues with latency and lack of local infrastructure, the report said.

"However, these localities may be able to compete for data centers running certain artificial intelligence workloads, such as training," the report said. "These localities could potentially become more attractive to the industry if they are able to proactively develop industrial sites suitable to data centers."

The report found that, so far, data centers are not driving bill increases for other classes of power customers, but with the major infrastructure needs on the horizon, that could change.

"Even though current rate structures appropriately allocate costs across customers, data centers' increased demand will likely increase system costs for all customers, including non-data center customers," the report said. "This is because current utility rate structures are not designed to account for sudden, large cost increases from the construction of new infrastructure to serve a relatively small number of very large customers."

The typical residential customer could see their bills rise by $14 to $33 per month by 2040 depending on how many data centers are built, the report said.

"Establishing a separate data center customer class is a first step utilities could take to help insulate residential and other customers from the energy cost impacts of the industry," the report said.

The report said co-ops treat data centers as their own separate class of customers already. It also suggests that Dominion Energy develop a plan to address the risk of any infrastructure investments being stranded with existing customers should the firm build infrastructure for data centers that do not come.

Another policy lever the state has is its sales tax exemption for new data centers, which provided $928 million in tax savings to the sector last year. The capital-intensive industry views that as a valuable incentive, and other states competing with Virginia support it.

The incentive has been in place since 2010 and is set to expire in 2035, and if the legislature let it lapse, development in the outer years would slow. The report also suggests cutting the incentive or tying it to requirements for data centers to maximize efficiency, or participating in demand response programs. ■

PJM News

Rising Transmission Costs in PJM Concern Consumer Advocates, Enviros

By Devin Leith-Yessian

Speakers at the PJM Public Interest and Environmental Organizations User Group's meeting Dec. 10 said the growth of local transmission projects is a major contributor to grid upgrades making up an increasing share of rates.

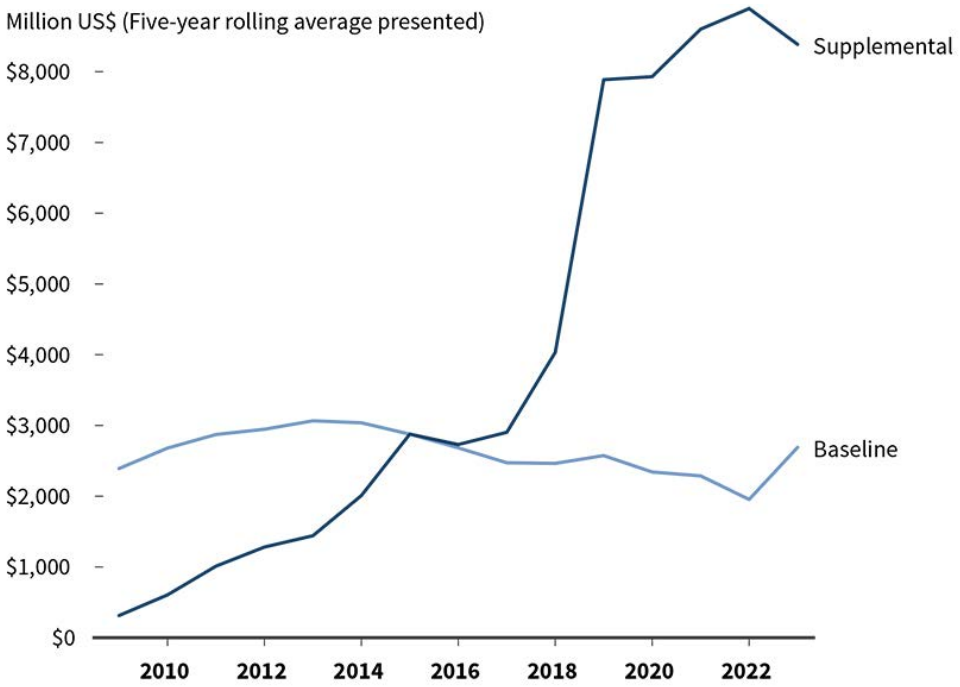
RMI's Claire Wayner *said* transmission and distribution are making up an increasingly larger amount of consumers' energy spending even as the number of line miles built is decreasing. Compared to regional projects that are reviewed at multiple levels to ensure reliability is delivered at least cost, local projects lack transparency and oversight, she argued.

Wayner co-authored a *report* for RMI, released in November, that recommended several changes to the regulation of local projects. It showed that while transmission spending nationwide hit a new high in 2023 — accounting for 24% of consumers' bills in 2020 compared to 10% in 2005 — the share of transmission spending that went to high-voltage projects has declined, falling from 72% in 2014 to 34% in 2021. In PJM, spending on local projects increased 26-fold between 2009 and 2023.

Many states don't require certificates of public convenience and necessity (CPCNs) for local projects, which Wayner said effectively exempts them from review at public utility commissions. In addition to expanding CPCN requirements, she said states can also create electric transmission authorities and establish expedited cost recovery for projects that have undergone regional review.

Wayner recommended that FERC require independent transmission monitors, consider performance-based regulation, and rework its formula rate process to eliminate the presumption of prudence and RTO adder for local projects that do not undergo regional review.

She also argued that PJM could improve its processes by creating windows for utilities to submit local needs to be reviewed by the RTO as it plans regional solutions; standardizing definitions and tracking of local projects; and providing states with more opportunities for input on regional planning.



An RMI report found spending on local transmission projects is driving an overall growth in transmission spending as a component of ratepayers' bills. | *RMI*

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), *said* he has submitted cost-related questions on dozens of local, supplemental projects in PJM's Planning Community portal and often received what he deemed inadequate or incomplete responses. In some cases, answers simply referred him back to the PJM website, which does not provide the detailed cost breakdowns he was seeking, he said.

"There is no ability to get more specific cost information than the sticker price of these projects," he said.

Poulos also identified 31 instances in 2023 in which supplemental projects presented to PJM's Transmission Expansion Advisory Committee were either already under construction or had been completed. He questioned what value there can be from stakeholder input on local projects that have already been completed.

CAPS has hired a consultant to further investigate how PJM's tracking of supplemental projects can be improved, he said.

Advocates Lay out 2025 Priorities

Poulos also *presented* several issues that consumer advocates intend to focus on next year, including changes to PJM bylaws and governance, removing barriers to storage development, improving participation in demand response programs and a sub-annual capacity market design.

With rising capacity prices and the elimination of energy efficiency from PJM's markets, Poulos said it is increasingly important for stakeholders to find opportunities for load to participate in the markets.

"It's a part of the equation that has just been ignored for way too long," he said.

Because consumer advocates make up one of five member sectors at PJM but only hold about 4% of non-sector-weighted votes at lower committees, he expressed skepticism that the stakeholder process could yield such changes directly. ■

National/Federal news from our other channels

Google Aims to Co-locate New Data Centers with Clean Power Projects

NetZero Insider

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SPP News

MISO, SPP to Revise Joint Agreement, Focus on TMEP Process in 2025

SAG Receives Update on M2M Settlements

By Tom Kleckner

MISO and SPP staff told stakeholders Dec. 13 that they will not perform a Coordinated System Plan in 2025 but will accept transmission issues for their annual review early in the year.

"This next annual issues review will be more of a check-the-box type of exercise than the normal, which would inform our decision to embark on a study in that particular year," Clint Savoy, SPP manager of interregional strategy and engagement, told members during a meeting of the RTOs' Interregional Planning Stakeholder Advisory Committee (IPSAC).

"What we're hoping to do with this process that we're trying right now would result in updates to the process going forward. I think that's something we're going to be considering as we're looking for ways to enhance the current CSP processes," he added. "First off, how do we improve on the needs that we're looking to provide solutions for and make sure we're looking at the right things? We always consider the transmission issues that our stakeholders submit, and oftentimes those lead to more targeted studies."

The IPSAC is scheduled to hold its annual meeting March 28, with stakeholders facing a Feb. 26 deadline to submit their issues for review. The meeting is required by the grid operators' Joint Operating Agreement, as is a CSP every other year.

Five previous CSP studies have failed to produce any joint projects over differences in allocating costs. That led the RTOs to try a different approach with the Joint Targeted Interconnection Queue (JTIQ), which identified a five-project portfolio estimated to cost as much as $1.6 billion that could support up to 29 GW of interconnecting generation along their seam.

FERC approved the JTIQ framework and cost allocation in November, and the Department of Energy in 2023 awarded the portfolio $464 million under its Grid Resilience and Innovation Partnerships program. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

The commission's approval of the JTIQ process has cleared the way for RTO staffs to revise the JOA language and refocus on their Targeted Market Efficiency Project (TMEP) process. They told stakeholders the *new study approach* will be much broader and forward looking and will be without predefined, specific historic issues to be resolved.

The RTOs plan to begin the study work in 2025. They are collaborating on a filing timeline and promised a stakeholder review will be shared at the IPSAC's annual meeting.

The TMEP process was used in the 2022 CSP. It studies smaller, congestion-relieving, cross-border transmission projects already in use between MISO and PJM. (See *MISO, SPP Take on 2nd Interregional Planning Effort*.)

Why This Matters

With their $1.6 billion Joint Targeted Interconnection Queue portfolio of large-scale transmission projects successfully approved, MISO and SPP are taking a breather and looking next year to refine their Targeted Market Efficiency Project process, which focuses on smaller, more immediate-need upgrades.

M2M Settlements Pass $600M

During a meeting of the SPP Seams Advisory Group, also on Dec. 13, staff reported that market-to-market (M2M) settlements with MISO have totaled $604.02 million through October in SPP's favor.

Under the M2M process that began in March 2015, the grid operators exchange settlements for redispatch based on the non-monitoring RTO's market flow in relation to firm-flow entitlements. Those settlements have steadily accrued to SPP, topping $100,000 in 2020, doubling in 2021 and doubling again in 2022.

However, the pace has slowed recently as the RTOs have added transmission to relieve congestion along the seam. Cumulative M2M payments exceeded $500 million in December 2023, but they only reached $600 million in October.

The notorious Neosho (Missouri)-Riverton (Kansas) flowgate accounted for $73 million in M2M settlements to SPP, according to a *staff report* to the SAG in December 2023. That number hasn't budged since then, an indication that SPP did not have any M2M settlements on the flowgate this year.

"This issue is likely resolved by the transmission construction that occurred in the Neosho area over the last two or three years," SPP spokesperson Meghan Sever said in an email. ■

The pace of market-to-market settlements has slowed, thanks to transmission upgrades. | *SPP*

SPP News

SPP Board Approves Need Dates for Last ITP Projects

Board also Acts on JTIQ Projects, MOPC Appointments

By Tom Kleckner

SPP's Board of Directors has finally approved the winter-weather staging of a pair of transmission projects that have been held up since October by stakeholder concerns over their need dates and whether they would be competitively bid.

During a virtual meeting Dec. 9, the board approved need dates for the two projects by endorsing the Markets and Operations Policy Committee's votes the week before: a December 2028 date for the 345-kV Tobias-Elm Creek transmission line on the western side of SPP's footprint and a December 2025 need date for the 345-kV Buffalo Gap-Delaware project from Kansas into Southwest Missouri.

The latter project's need date was amended from December 2028 during the MOPC meeting, overriding staff's recommendation. (See *SPP Stakeholders Endorse Need Dates for Delayed Transmission Projects*.)

The board's approval completes the 2024 Integrated Transmission Planning assessment, a record-breaking $7.65 billion portfolio of 89 projects. The directors delayed a decision on the last two projects' need dates — the earliest that staff identify a project is needed — after failing to reach consensus during several hours of discussion in their October meeting. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

Evergy and other Missouri and Kansas stakeholders were particularly keen on moving up the 154-mile, $484.1 million Buffalo Gap-Delaware project, which brings a new extra-high-voltage source into Missouri that will support mitigation of Wichita-area congestion, Missouri system voltage and transfers from the SPP footprint into Missouri. The project was identified through a model based on December 2022's Winter Storm Elliott that also analyzed 2025 and 2028.

Evergy, with operations in both states, joined with City Utilities of Springfield (Mo.) and Liberty Utilities in filing a letter before the board meeting urging the earlier need date. They said establishing an immediate need-by date is consistent with SPP's tariff and the ITP manual; the project will address reliability violations found in all the models and decrease the risk of load shed; and it has broad stakeholder support.

SPP's Board of Directors has approved the staging for two transmission projects that have been held up for two months. | *SPP*

"SPP took a novel approach this year to address resiliency projects by studying select winter weather events because they knew … there was a problem that needed to be addressed that hadn't been addressed previously, and some of that work resulted in the single most cost-effective ITP in SPP history," said Kayla Hahn, chair of the Missouri Public Service Commission. "Unfortunately, I'm concerned that that work could potentially be undercut by the delay of this particular project."

"We have known for some time that the environment created by our generational challenge will put pressure on many aspects of our processes and culture, whether it be setting a longer-term [planning reserve margin] fully assessing resiliency and winter weather scenarios, or assessing our short-term reliability project list," board Chair John Cupparo said. "We will be facing unprecedented situations that may run counter to our experience on how to analyze and address these issues. How we respond to those situations may also deviate from historical practice but must still be consistent with our regulatory obligations and our mission."

The board's Members Committee approved the Buffalo Gap-Delaware project with its advisory vote, 16-6, opposed primarily by renewable interests.

"We've heard a lot about how these upgrades are needed for reliability. We've been burned by making decisions based on [transmission owners] saying one thing publicly but not moving forward on much-needed transmission," EDP Renewables' David Mindham said. "There's currently no way to hold TOs accountable for not building transmission timely in SPP. If we have the later need date, these projects will be competitive, and that shines a big old spotlight on" the TOs.

The committee approved the Tobias-Elm Creek Project, 11-7, with four abstentions. TOs were in the opposition, with some saying they still had questions over staff's use of the winter models. The project is an 85-mile segment valued at $887.5 million.

JTIQ NTCs Coming Soon

The board endorsed staff's recommendation to approve the three SPP projects in the Joint Targeted Interconnection Queue (JTIQ) port-

SPP News

folio with MISO and directed the RTO to issue them notifications to construct.

The three projects — a new 345/161-kV double circuit and rebuilt 161-kV lines near Omaha, Neb.; new 345-kV lines in Nebraska; and an expanded and rebuilt 345-kV substation in Sibley, Iowa — cost a combined $436 million, according to 2023 conceptual engineering and construction estimates. The JTIQ portfolio's five projects cost a combined $1.6 billion.

However, SPP and MISO expect a grant of up to $464.5 million in matching federal funds under the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) program to offset some of the projects' capital costs. (See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.)

FERC in November approved tariff revisions and modifications to the joint operating agreement between the two grid operators that enshrines a structural and cost-allocation framework for the five 345-kV projects (*ER24-2798*, *ER24-2825*). The RTOs plan to allocate 100% of the projects' costs to interconnection customers, consistent with the cost-causation principle. (See *FERC Approves JTIQ Framework, Cost Allocation*.)

The effort began in 2020. The RTOs say the portfolio will enable between 28 GW and 53 GW of interregional generation capacity near their seam.

The committee unanimously favored the motion, 22-0.

Lang, Hough to Lead MOPC

By approving its consent agenda, the board sided with the Corporate Governance Committee's recommendation that Omaha Public Power District's Joe Lang and City Utilities of Springfield's Olivia Hough serve as MOPC's chair and vice chair, respectively. They will serve two-year terms expiring Dec. 31, 2026.

The agenda's approval also results in the following organizational group chairs for the next two years:

- Credit Practices Working Group: Caleb Head, Northeast Texas Electric Cooperative.
- Economic Studies Working Group: Calvin Daniels, Western Farmers Electric Cooperative.
- Project Cost Working Group: Angie Anderson, Sunflower Electric Power.
- System Protection and Control Advisory Group: David Oswald, Liberty Utilities.
- Market Working Group: Richard Ross, American Electric Power.
- Operations Training Users Forum: Derek Stafford, Grand River Dam Authority.
- Generation Interconnection Advisory Group: Jason Tanner, NextEra Energy.

All the chairs are incumbents except for Oswald and Tanner. Both are currently their groups' vice chairs.

The consent agenda will also revise the PCWG's scope to include reviewing delayed upgrades and providing recommendations to the board in a timely manner. ■

Company Briefs

Eversource Credit Ratings Downgraded

S&P Global Ratings downgraded the credit ratings of a pair of Eversource Energy subsidiaries.

Eversource's electric distribution company, Connecticut Light & Power, was downgraded from an "A" to an "A-" while the company's natural gas subsidiary, Yankee Gas, saw its rating drop from an "A-" to "BBB."

With the credit ratings, S&P cited a negative regulatory environment for Connecticut utilities because of Public Utilities Regulatory Authority rulings that have either dramatically reduced or eliminated requested rate increases.

More: *CT Insider*

BP Forms OSW Joint Venture with Japan's JERA

BP and Japanese power generator JERA announced that they have agreed to a 50-50 joint venture called JERA Nex bp.

The companies said they will pool together almost all their operating assets and development projects with a potential capacity of 13 GW. The partners have agreed to provide up to $5.8 billion in funding for projects approved by the joint venture by 2030, with BP contributing up to $3.25 billion and JERA paying up to $2.55 billion.

More: *Business Standard*

CenterPoint Energy Announces Senior Leadership Changes

CenterPoint Energy last week announced several senior leadership changes that will take effect on Jan. 1, 2025.

The changes include the appointments of Richard C. Leger as senior vice president of CenterPoint's multistate gas business and Bertha Villatoro as senior vice president and chief human resources officer. Leger has served in his current role on an interim basis since July 2024.

Lynne Harkel-Rumford, who currently serves as executive vice president and chief human resources officer, will retire Feb. 3, 2025.

More: *CenterPoint Energy*

Federal Briefs

EIA: US Power Use to Reach Record Highs in 2024, 2025

U.S. power consumption will rise to record highs in 2024 and 2025, the Energy Information Administration said in its Short-Term Energy Outlook.

EIA projected power demand will rise to 4,086 billion kWh in 2024 and 4,165 billion kWh in 2025, compared to 4,012 billion kWh in 2023 and a record 4,067 billion kWh in 2022.

More: *Reuters*

Supreme Court Rejects Co-op Attempt to Block EPA Ash Rule

The Supreme Court last week rejected a request from the East Kentucky Power Cooperative to block an EPA effort to address the health risks presented by coal ash.

The utility challenged the EPA's plan in a federal appeals court, saying the agency exceeded its statutory authority by requiring monitoring and remediation at facilities that were no longer producing coal ash. The utility also asked the appeals court to block the plan while it considered the matter, a request the court denied. The utility then asked the Supreme Court to intervene, saying the statute at issue applied only to sites where solid waste "is disposed of." The present tense, it said, excluded inactive sites where it said coal ash had been removed.

The court's brief order gave no reasons and there were no noted dissents.

More: *The New York Times*

DOE Says LNG Reviews Must Wait for FERC

DOE last week said it is not able to complete reviews of two planned LNG export terminals in Louisiana until FERC finishes its environmental assessments of the projects.

The projects are Venture Global LNG's CP2 facility and a facility from Commonwealth LNG, both located on the Gulf of Mexico.

The additional review follows an Aug. 6 decision by the D.C. Circuit Court of Appeals that quashed FERC's approval of NextDecade's plant and ordered the commission to reconsider the project ramifications with a new environmental statement and public comment period.

More: *Reuters*

Biden Admin Doubles Tariffs on Chinese Solar Panel Components

The Biden administration last week announced it will double tariffs on certain solar panel components that are made in China.

Starting in January, imports of Chinese solar wafers and polysilicon will carry a 50% tariff, up from the current levy of 25%. In addition, the administration said it would increase tariffs on certain Chinese products made out of the mineral tungsten.

More: *The Hill*

Rep. Guthrie to Lead House Energy and Commerce Committee

Rep. Brett Guthrie (R-Ky.) won the race to lead the House Energy and Commerce Committee next year and will replace retiring Chair Cathy McMorris Rodgers (R-Wash.).

Guthrie, who currently chairs the panel's Subcommittee on Health, beat out Rep. Bob Latta (R-Ohio) for the post.

More: *Axios*

State Briefs

CALIFORNIA

PUC Delays Vote on Aliso Canyon Closure

The Public Utilities Commission last week issued an order to extend the deadline to vote on a proposed closure plan for Southern California Gas' Aliso Canyon natural gas storage facility until March 31.

The PUC said it needed to ensure it had "ample time to thoughtfully deliberate on the proposed decision and address any unexpected issues in that process."

The PUC was set to vote Dec. 19 on a plan to consider eventually shutting down the facility.

More: *E&E News*

COLORADO

Denver Modifying GHG Rules After Landlord Protests

Denver's climate change and energy officials said they will modify a set of greenhouse gas reduction rules for big buildings after challenges from landlords.

Like state rules covering large buildings, Denver in 2021 passed "Energize Denver," with a target of 30% cuts to buildings' "energy use intensity" by 2030 and net zero on carbon in 2040. The city law, which started in 2023, requires owners of large buildings to get extensive energy audits and return with plans to reduce energy use and carbon output against a 2021 benchmark.

Denver officials agreed to keep negotiating with the property owners, and issued a revised set of rules they say eases the timelines for the audits and the required targets.

More: *The Colorado Sun*

INDIANA

Federal Judge Blocks Law Giving In-state Utilities First Dibs on Projects

Chief Judge Tonya Walton Pratt blocked a state law passed in 2023 that gives the major utilities the right of first refusal for electric transmission projects.

House Enrolled Act 1420 changed state code to allow utilities first dibs on transmission projects that are approved by MISO.

"HEA 1420, though not a complete ban on out-of-state transmission owners, erects a barrier to the interstate electric transmission market by limiting who can compete for new construction projects in Indiana," Pratt wrote. "The right of first refusal in favor of Indiana incumbents runs contrary to the Supreme Court's admonition that 'states cannot require an out-of-state firm to become a resident in order to compete on equal terms.'"

More: *Indianapolis Star*

Gov.-elect Braun Taps Jaworowski for Energy Secretary

Gov.-elect Mike Braun last week named **Suzanne Jaworowski** — an electricity system official who previously worked for President-elect Donald Trump — as his pick for energy and natural resources secretary.

Jaworowski will oversee the Department of Natural Resources, Department of Environmental Management, Utility Regulatory Commission and several other agencies.

Jaworowski was most recently the executive director of stakeholder services for MISO. She previously spent time as an energy consultant and made an unsuccessful bid for Indiana House in 2022.

More: *Indiana Capital Chronicle*

MARYLAND

Commission Votes to Study Ways to Pay for Climate Plan

The Commission on Climate Change last week adopted amendments to the state's original climate plan recommendations for generating revenues that instead call for studies on how those proposals could be implemented.

Last year a state environmental agency calculated that it would cost Maryland at least $10 billion to meet the government climate mandates. Instead of recommending a cap-and-invest program, the commissioners unanimously accepted an amendment proposed by Environment Secretary Serena McIlwain that would instead urge the legislature to authorize a study of how a cap-and-invest program would be implemented, how it would impact consumers and how much revenue it might generate.

The recommendation also suggests the legislature direct the Department of the Environment to establish a rule that would require fossil fuel companies in the state to annually report their greenhouse emissions beginning in 2027.

More: *Maryland Matters*

MINNESOTA

CenterPoint Reaches Settlement on Gas Rates

CenterPoint Energy last week filed a settlement with the Public Utilities Commission that will raise residential gas rates by 5.2%.

The increase equals about $50 per year for most customers compared to 2023 levels. CenterPoint initially requested a 10.3% increase.

The settlement will also slash the amount in membership dues CenterPoint can pass onto customers for belonging to organizations that lobby on behalf of the natural gas industry.

More: *Sahan Journal*

NEW JERSEY

Assembly Committee Approves Delay of Clean-truck Rule

The Assembly Transportation and Independent Authorities Committee last week unanimously voted to advance a bill that would delay by two years implementation of the Advanced Clean Truck rule, which was set to go into effect in January.

The rule would require manufacturers of medium- and heavy-duty trucks to sell an increasing percentage of new battery-powered vehicles each year.

The bill still needs to pass a full Assembly and Senate.

More: *NJ Spotlight News*

NORTH DAKOTA

Industrial Commission Approves Carbon Dioxide Storage Permits

The Industrial Commission last week unanimously approved permits for Summit Carbon Solutions' three proposed carbon dioxide underground storage sites.

Summit's proposed 2,500-mile, $8 billion

pipeline would transport CO_2 emissions from 57 ethanol plants in North Dakota, South Dakota, Iowa, Minnesota and Nebraska for underground storage. Summit's storage facilities would hold about 352 million metric tons of CO_2 over 20 years.

More: *The Associated Press*

OKLAHOMA

Supreme Court Refuses to Stop OCC Commissioner from Voting

The state Supreme Court voted 8-0 to refuse to block Corporation Commissioner Todd Hiett from voting on rate hikes because of accusations of misconduct.

One justice said the Ethics Commission, and not the Supreme Court, was the more appropriate avenue for the disqualification request.

Hiett has been accused of inappropriate actions while intoxicated, according to reports.

More: *The Oklahoman*

TEXAS

Austin Approves Energy Generation Plan

The Austin City Council last week unanimously approved the "Austin Energy Resource, Generation and Climate Protection Plan to 2035."

The plan lays out city priorities such as continuing to move toward 100% carbon-free energy by 2035 and improving reliability, affordability and environmental sustainability.

More: *KXAN*

WEST VIRGINIA

PSC Imposes Stricter Standards on Mon Power, Potomac Edison

The Public Service Commission told Monongahela Power and Potomac Edison that it was imposing stricter standards to reduce service interruptions for customers.

The new standards will require the companies to meet a 2% improvement. The improvement will be measured by two factors: average interruption duration and outage frequency.

More: *WDTV*

WISCONSIN

We Energies Plans New Gas-fired Plant to Meet Growing Demand

We Energies announced plans to build a new natural gas-fired plant in Kenosha County, arguing the project is critical to meeting increasing demand.

The plan to build a $300 million gas plant in the town of Paris is part of a planned $2 billion investment in natural gas infrastructure. The biggest chunk of that is a $1.2 billion project to transition the company's Oak Creek site from coal to natural gas. The projects, along with a 33-mile natural gas pipeline, will need to be approved by the Public Service Commission.

The company hopes to begin construction next year and bring the plant online in 2026.

More: *Wisconsin Public Radio*

PSC OKs Portage County Solar Farm

The Public Service Commission last week approved the Vista Sands Solar Project in Portage County.

The project will be the largest in the state and among the most powerful in the country, generating nearly 1.3 GW.

More: *Stevens Point Journal*

WYOMING

PSC Approves Rocky Mountain Power Rate Increase Settlement

The Public Service Commission last week approved a settlement agreement that finalizes an $80.6 million increase for Rocky Mountain Power.

The settlement is about 7% less than the company's original request of $86.4 million. Officials later said the initial figure was in error and was adjusted.

The average residential bill will increase by about $11.95.

More: *WyoFile*

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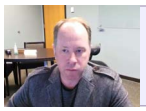

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