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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: CAISO said 240 attendees turned out for its EDAM Forum in Las Vegas. |

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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

FERC Order 2023 Gets Rehearing Requests from Around the Industry

By James Downing

FERC received rehearing requests last week from around the industry on Order 2023, which mandated changes to its *pro forma* interconnection rules. (See *FERC Updates Interconnection Process with Order 2023*.)

MISO, PJM and SPP filed a joint request for rehearing, saying they want to ensure that they can continue to innovate with their own changes to their interconnection processes.

The RTOs took issue with the order's requirement that planners use operating assumptions supplied by energy storage developers, unless they go against good utility practice. Ensuring that storage owners actually follow those assumptions in their operations would be burdensome and impractical, they said.

"Storage would be incentivized to lower their costs by stating in their interconnection application their intent to charge to relieve constraints, when in actuality in real time they will not always be capable of fulfilling that commitment," the RTOs said. "As a practical matter, there is no effective enforcement of the commitment, and the final rule does not purport to address this critical reliability issue."

FERC at least should allow ISOs and RTOs to develop standard procedures for dealing with storage projects in their queue, rather than the case-by-case approach in the order, which would at least promote uniformity in treatment of similarly situated interconnection customers.

PJM, MISO and SPP all use multiphase interconnection processes, but Order 2023's *pro forma* rules have just one phase, used to base the deadlines and related fines that grid operators face for late studies. That makes it unclear how the rules should apply in their markets, the RTOs said. Rather than making them liable for deadlines in each phase, they asked to have it apply to the aggregate timeline of their multiphase queue processes.

Ultimately interconnection customers want their final studies on time, so as long as the full process is timely, it should not matter if some earlier phases experienced delays that were made up later, the three said. Late penalties also should apply to entire clusters, rather than having planners face them for every project they work on individually.

ISOs and RTOs are nonprofits, so another issue the three raised was how to recover their costs, asking for additional ways beyond collecting fines from their members. If a delay is because of one interconnection customer, as opposed to the grid operator itself or a member utility, then it should be liable for any fines, they argued.

NYISO filed its own request for rehearing, which also questioned the fines, but it focused on the timelines that Order 2023 set out for interconnection studies. The 150-day time frame for a cluster study is not tailored to the realities of New York's grid and its stricter-than-average reliability requirements, but it still could be used to assess fines.

"These stringent criteria are driven by, among other things, the unique complexities of the transmission system in New York City and Long Island, with their condensed geographic footprint and high population density," NYISO said. "This existing complexity is being further challenged by the influx of significant offshore wind generation."

NYISO is working on a package of changes to its queue, and its goal is to speed up the process, but 150 days would prove too tight for it.

| NYPA

New York PSC Argues in Favor of Fines

The New York Public Service Commission filed comments arguing that FERC should make sure that ISOs and RTOs cannot get out of the fines that Order 2023 requires for transmission planners who are late with interconnection studies. The order suggests grid operators could file one-off requests to recover the fines from market participants, it said.

"Allowing RTOs/ISOs to simply pass along penalties to market participants, which will ultimately be borne by customers, would undermine [FERC's] goal by making RTOs/ISOs indifferent to penalties and failing to induce the intended behavior," the New York PSC said. "Moreover, forcing market participants/customers to pay increased costs attributable to penalties incurred by an RTO/ISO that failed to comply with the tariff time deadlines would be unjust and unreasonable."

FERC has expressly prohibited non-ISO/RTOs from recovering the penalties through transmission rates, and it should do the same for the nonprofit grid operators, the PSC said. It also should reverse its finding that they can make a one-off filing to recover penalties from market participants.

"The commission should instead limit RTO/ISO recovery options to alternative mechanisms that do not involve customer funding but could elicit the desired behavior, such as adjustments, both positive and negative, to RTO/ISO salaries/bonuses," the PSC said.

Utilities Lobby for 'Reasonable Efforts' Standard

The Edison Electric Institute also took issue with FERC's decision to eliminate the "reasonable efforts" standard for getting interconnection studies in on time and the imposition of fines. FERC cited the lengthy interconnection delays experienced around the country as the main reason for eliminating the standard, but it did not connect those delays to the standard.

"Only after the commission has had an opportunity to evaluate the efficacy of other reforms intended to streamline the interconnection process (e.g., reforms to incentivize interconnection customers to reduce interconnection delays) can it determine that the reasonable efforts standard is unjust and unreasonable," EEI said.

A rapidly changing resource mix, market forces and emerging technologies are among the many factors contributing to the increasing number of interconnection requests and related delays. Transmission owners can control none of those factors, and assigning them penalties will not change that, EEI said.

FERC never has found a transmission provider at fault for interconnection process delays, nor shown that any specific transmission provider was contributing to delayed studies, it said.

"Nonetheless, the commission seems intent on establishing a strange kind of parity in its reforms: If the threat of penalties is appropriate for eliciting certain behavior from one set of stakeholders, then penalties must be appropriate for all stakeholders in the interconnection process," EEI said. That does not make sense because many factors, including the number of requests and the need to follow reliability standards, are outside transmission providers' control, it said.

Clean Energy Groups Seek Changes

The American Clean Power Association, Advanced Energy United and Solar Energy Industries Association filed a joint request for rehearing, which applauded FERC for its work to reform the queues. But given how large the order was, the groups said they have some issues where the order would benefit from rehearing.

The groups' first ask is to remove a change to the definition of "standalone network upgrade" that would limit their construction to cases where one interconnection customer builds them. FERC reasoned the change would reduce disputes by avoiding situations where multiple interconnection customers seek to build the same transmission. But cluster studies for interconnection have occurred for years and have not led to major disputes between projects seeking to build the same standalone upgrade, they said.

"The revised definition of standalone network upgrade removes the ability of interconnection customers to determine whether and how to exercise their discretion or the option to build for the majority of upgrades that will be identified through a cluster study," the groups said. "It further modifies the status quo by reducing the number of network upgrades that would qualify as standalone network upgrades for which interconnection customers could exercise their discretion."

The groups generally pushed for more flexibility for interconnection customers, also seeking more time to modify a proposed project's size and to push back when they have to pick a definitive point of interconnection. The commission required both when the "customer engagement window" ends, reasoning that developers would have enough information at that point to make final decisions.

The three lobbies argued more flexibility was warranted because requiring final decisions so early would lead to more withdrawals later on and risk "cascading restudies." That would be more disruptive than allowing minor changes later in the process, they said.

Heat Map Value Questioned

Several utilities outside of RTOs — Dominion Energy South Carolina, NextEra Energy's Florida Power & Light and Xcel Energy's Public Service Company of Colorado — filed jointly asking for a change to the requirement that grid planners place interactive "heat maps" on their public websites. The maps would offer interconnection customers and others a way to explore available interconnection capacity on transmission providers' systems.

The utilities said FERC failed to perform a cost-benefit analysis on the requirement, which would cost $7.4 million upfront in non-RTO regions and $666,000 annually for maintenance. The requirement will have "dubious value" for interconnection customers in non-RTO regions, they said.

Such heat maps make financial sense when done at scale for several utilities, so it could make sense to require ISO/RTOs to host them, but the three utilities said the lack of scale on individual systems made it too costly.

"Due to the significant cost asymmetry — 37 individual websites required in non-RTO regions versus seven websites in ISO/RTO regions — the cumulative expense and administrative burden on constrained engineering labor caused by the heat map mandate on transmission providers in non-RTO regions is at least five times as significant as the burden on ISOs/RTOs, even though transmission providers in non-RTOs only oversee generator interconnections for roughly one-third of the nation's transmission systems," they said.

Flexibility Sought

PacifiCorp spent much of its rehearing request focused on the penalties for transmission providers, but it also argued for more flexibility for it and others to implement the rules. The utility noted that it already has adopted many of the changes required by Order 2023.

FERC set up a transition process for providers still using its old *pro forma* rules but not for early actors such as PacifiCorp, the utility said. If it does not seek a variance from the *pro forma* rules, it would have to implement them suddenly regardless of the existing queue, it said.

"PacifiCorp and many of the early adopters are currently in the process of one or more cluster studies," the utility said. Not allowing early adopters to use a transition cluster study process is both unworkable and goes against FERC's assurance that Order 2023 would not interfere with interconnection studies in progress, it added.

On rehearing, FERC should find that PacifiCorp and other similarly situated transmission providers can process existing interconnection customers under current, or transitional rules, while applying new reforms to interconnection customers once those are completed, it said.

PJM filed an individual request for rehearing that also was focused on flexibility, given that it has started to implement its own changes, which it said should satisfy Order 2023's requirements or be superior to them. While FERC said it did not want to disrupt such efforts, PJM said it wants a clearer signal before any lengthy compliance processes that its work will not be overturned.

Without that clarification, FERC will be responsible for creating uncertainty at the very

FERC/Federal News

point where certainty around the rules for expeditious processing of queue requests is so critical, the RTO said.

"In short, now, when PJM is 'mid-flight' with its new interconnection process, is not the time to require PJM to substantially retool its interconnection processes or to cause substantial uncertainty as to how to comply with the final rule that will last for months and distract from the vital effort to process backlogged interconnection requests as expeditiously and efficiently as possible," the RTO said.

PJM also wants clarification that it will not be required to implement the final rule in a way that would modify or undermine its recently approved new rules. The commission should consider those changes as a package and not require PJM and stakeholders to engage in "an item-by-item justification of every variation from the minutiae of the final rule's requirements."

Along with most other transmission providers filing for rehearing, American Electric Power wants FERC to reverse its decision on imposing fines for delayed studies, but the company also asked for some changes on how new projects can be built at sites owned by retired power plants.

"Generation retirement replacement programs take advantage of current land use and interconnection facilities to swap generation units set for retirement with newer, more efficient capacity," AEP said. "Such programs will support the reliability of the grid and enhance the efficiency of interconnection study processes by allowing for the timely interconnection of needed new capacity resources."

AEP and a few other parties brought up the issue in comments, but it was not part of the Notice of Proposed Rulemaking that led to Order 2023, it said, and FERC said it lacked the evidence to approve any *pro forma* rules around how to replace retiring generators. The utility disagreed, saying the idea is one of the most vital tools to maintaining resource adequacy, as they can quickly connect new supplies of power.

"Ensuring replacement projects are considered outside the cluster study process will help reduce the number of projects within, and increase the efficiency of, the cluster study itself — supporting the timely interconnection of projects consistent with one of the primary purposes of Order 2023," AEP said.

WATT Coalition Lobbies for DLRs

The WATT (Working for Advanced Transmission Technologies) Coalition filed for rehearing on two issues involving dynamic line ratings (DLRs), which take into account the conditions around power lines such as wind speed and temperature to get a more accurate picture of how much capacity they have.

FERC excluded DLRs from its list of alternative transmission technologies (ATTs) that can be considered in cluster studies. It also allowed transmission providers to "disregard and disadvantage" alternative technologies for traditional upgrades even when alternatives would be more cost effective.

DLRs were part of the alternative technologies to be considered in the NOPR, but in the final rule, FERC removed them despite them being proven, mature technologies that have saved interconnection costs in other countries, WATT said.

One WATT member was quoted $190 million in upgrades for one projected 4% transmission line overload during the shoulder season, with the grid operator assuming it would charge during the worst-case contingency events.

"The battery would provide energy to an area of anticipated economic development but would be uneconomic with quoted upgrades," WATT said. "DLR is a solution that could bring the project back into viability if permitted by the transmission owner."

FERC got comments for and against every ATT brought up in the NOPR, but it only removed DLRs, saying their temporary impact "may not be an adequate substitute" for steel in the ground, WATT noted.

"DLRs should be treated on equal footing with the other ATTs included in the final list, and as the NOPR proposed," WATT said. "Equally, it is arbitrary and capricious, and contrary to law, to give transmission providers unfettered discretion regarding whether ATTs should in fact be used." ■

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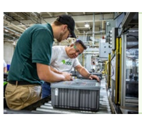

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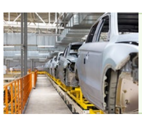

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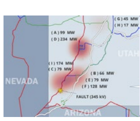

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FERC/Federal News

DOE Announces $300 Million for Tx Siting and Community Development

$760 Million in Total Will be Available for Permitting, Development

By James Downing

The Department of Energy last week announced a $300 million grant opportunity for states, tribes and local governments to strengthen their transmission siting and permitting processes.

Funding for the Transmission Siting and Economic Development (TSED) program comes from the Inflation Reduction Act and is administered by DOE's Grid Deployment Office. The program is meant to accelerate the construction of new transmission infrastructure, which is vital to the Biden administration's net-zero goals.

"To meet our ambitious clean energy goals, we need to expand the nation's transmission capacity by 60% over the next seven years," said Energy Secretary Jennifer Granholm. "We have the funding to build out a grid chock-full of clean, cheap, reliable electricity and accelerate transmission expansion while creating good-paying jobs across the country."

The $300 million is the first tranche of a total $760 million for the TSED program under the IRA and is available for permitting processes and economic development in affected communities. The program covers siting for any onshore transmission lines at 275 kV and above and offshore lines of 200 kV and above.

Independent estimates project that transmission will need to expand by 60% by 2030 and may need to triple by 2050 to meet the demand for clean electricity and resiliency. The TSED program will provide financial support to siting authorities to fund studies, modeling, environmental planning and analysis to assess alternatives, better inform decision-making and cut application processing time.

| Great River Energy

Government siting agencies will be able to use the money to study up to three alternate siting corridors for transmission projects. Regulators can use it to participate at FERC or other agency proceedings for determining the rates and costs of a project they site.

The program also can support robust engagement with members of the public, participation in regulatory proceedings and other activities as approved by the secretary of energy.

The program's community-based projects can include energy investments such as microgrids, renewable power integration and electric vehicle charging infrastructure. They can support essential community facilities for public safety, health care, education and transit, or community centers and parks.

TSED funds can also be used for job training and apprenticeship programs. DOE wants communities to submit unique projects that are suited to local needs.

Transmission developers are not eligible for the grants, but they can partner with government agencies that are. Developers can work with siting and permitting agencies to propose improvements to cross-jurisdictional coordination, strengthen permitting processes and resolve permitting bottlenecks.

The department wants initial concept papers from potential grantees by Oct. 31 and full applications by April 5, 2024. ■

CAISO/West News

Backers of Independent Western RTO Seek to Move Quickly

By Robert Mullin

California PUC President Alice Reynolds (left) and Oregon PUC Commissioner Letha Tawney at CAISO's EDAM Forum in Las Vegas | © *RTO Insider LLC*

LAS VEGAS — The coalition of utility commissioners that this summer proposed the creation of an independent Western RTO is wasting no time getting the project up and running.

That spells good news for CAISO, one of the key beneficiaries of the effort as it seeks to stand up its Extended Day-Ahead Market (EDAM) in the face of increasing competition for participants from SPP's Markets+ offering.

The group, which includes regulators from Arizona, California, New Mexico, Oregon and Washington, on Aug. 29 issued a *notice* inviting a broad range of stakeholders from across the Western U.S. and Canada to "help build" Phase 1 of the effort, which will include "deciding on the form, mission, and scope of an entity with independent, West-wide governance."

"This effort, the 'West-Wide Governance Pathway Initiative,' seeks to build on the benefits of [CAISO's] Western Energy Imbalance Market (EIM), realize the potential benefits of an extensive footprint for the Extended Day-Ahead Market (EDAM) and enable a path forward for a potential West-wide fully organized market (a regional transmission organization or RTO), should participants in this effort so choose," the notice said.

The regulators first floated the RTO plan in a July *letter* just as the growing competition between CAISO and SPP raised the prospect that the West could become divided into two day-ahead markets that eventually would evolve into separate RTOs.

The commissioners' proposal cited studies showing the West would reap the greatest economic and environmental benefits from a single market — and one that pointedly includes CAISO. The plan seeks to create a workaround for an issue that for years has bogged down CAISO's attempts to expand into an RTO: its state-run governance. (See *Regulators Propose New Independent Western RTO*.)

'With All Urgency'

In the notice issued last week, the regulators made clear they plan to pursue an aggressive timeline for laying the groundwork for the effort. They seek to "finalize key elements of the independent entity's governance" by December and to select and seat a founding board by January. The Regulatory Assistance Project will provide "staffing and facilitation" for the initial phase, which will be led by Carl Linvill and Jennifer Gardner, both former members of the WEIM Governing Body.

"Funding derived exclusively from 501(c)(3) sources will support the initial work of this initiative," the notice said. "This arrangement will be evaluated over time and will likely require supplementation as the workload intensifies. We commit to ensuring that the initiative has access to consultants and advisors on the broad array of topics that may become relevant as the work proceeds."

The commissioners acknowledged that Phase 1 of the effort "is being facilitated outside of any existing organization or decision-making process and asked stakeholders to provide feedback on a series of questions — outlined in the notice — about how to structure the stakeholder process. Comments are due by Sept. 11.

"I think there's a lot of work in front of us to make sure that stakeholders are widely engaged, that public power has a seat at the table [and] that the [investor-owned utilities], the public interest organizations [and] the consumer advocates are all invited into that conversation and that it moves with all urgency," Oregon Public Utility Commissioner Letha Tawney, a signatory of the July letter, said Wednesday in Las Vegas at a forum focused on CAISO's EDAM.

"We propose a bit of a scope, decisions about a legal entity, a charter, a mission, a founding board. That's ambitious," Tawney said. "I'd love to hear, is that sufficient? Is it insufficient? Given how ambitious it is, is something else feasible?"

Speaking at the EDAM forum, California Public Utilities Commission President Alice Reynolds said the July letter was intended to take the problem of CAISO's governance off the table. The process ahead, she said, will need to examine what an independent entity "needs to look like."

"How we can build this so that there is an entity to provide the full range of options for regional cooperation, recognizing that we may not ultimately use all of them? Some of us might, some of us might not, but at least we'd have a path to the full range of benefits," said Reynolds, who also signed the July letter.

"How can we get there as a region and really confront this 500-pound gorilla in the room of governance?" Arizona Corporation Commissioner Kevin Thompson said at the forum. "If we could solve that issue, then let's solve it and move on for the benefit of not only our utilities, but the benefit of our consumers as well." ■

BANC Moving to Join CAISO's EDAM

By Robert Mullin

LAS VEGAS — CAISO scored a potentially important victory Wednesday when the Balancing Authority of Northern California (BANC) said it will pursue membership in the ISO's Extended Day-Ahead Market (EDAM) — and not SPP's Markets+.

BANC General Manager Jim Shetler revealed the decision during a CEO panel discussion at a CAISO EDAM Forum held at Resorts World on the Las Vegas Strip.

"I'm pleased to announce that at our strategic planning session a week ago today, staff recommended to the [BANC] commission that we move forward with participation in EDAM as our option for day-ahead market participation, and I'm pleased to say our commission unanimously endorsed that recommendation," Shetler told an audience of about 240 electric industry participants attending the event.

BANC is a joint powers authority that manages system operations for six municipal utilities: Sacramento Municipal Utility District (SMUD), Modesto Irrigation District, Roseville Electric, Redding Electric Utility, Trinity Public Utility District and the city of Shasta Lake. With about 5,000 MW of load, BANC is the third-largest BA in California and the 16th largest in the Western Interconnection. Its footprint also includes the Western Area Power Authority's transmission grid in the Sierra Nevada region (WAPA-SN).

Shetler said each of its members would have to decide individually whether to join the EDAM but pointed out that SMUD — California's second-largest municipal — also has received approval from its board to engage with BANC on participating in the new day-ahead market. SMUD was the first BANC utility to begin trading in CAISO's real-time Western Energy Imbalance Market (WEIM) in 2019.

"Engaging with BANC to participate in the EDAM is a natural progression from SMUD's participation in the WEIM," SMUD CEO Paul Lau said in a statement. "Not only is the EDAM an important tool to support reliability and resiliency and low rates while helping SMUD deliver on our industry-leading decarbonization goals, it will also provide broader price, reliability and decarbonization benefits in support of regional goals."

Shetler said Modesto, Roseville and Redding were all in "various stages" of obtaining approval from their boards, while WAPA-SN will be kicking off the federal process to gain its approval in September. He said BANC is looking to go live in the new market in 2026.

BANC is the second entity to commit to the EDAM behind PacifiCorp, which controls a large amount of transmission and generation in six Western states through its Pacific Power and Sierra Pacific utilities.

Sharing the dais with Pacific Power CEO Stefan Bird and CAISO CEO Elliot Mainzer in Las Vegas, Shetler said he looked forward to working with their staffs to "make EDAM a reality."

'Clear Winner'

At a press briefing at the forum on Wednesday, Shetler spelled out the reasons BANC decided to go with the EDAM, including its ability to help members meet their decarbonization goals.

Jim Shetler, Balancing Authority of Northern California | *© RTO Insider LLC*

"And the other dynamic here is, as markets evolve, if you're not in a market, you do run the risk of losing your counterparties for trading going forward. That was certainly a decision for some of my members when we joined the WEIM," he said.

But BANC's decision to choose the EDAM over Markets+ appeared to come down to geography.

"I think the main driver for any market decision is what are your transmission capabilities and who you're interconnected with, and we have tremendous interconnection capability with the ISO through our footprint," he said. "And it just made sense for us when we did our evaluation, both from a cost standpoint [and a] potential benefits standpoint, that EDAM came out as a clear winner."

Shetler acknowledged the reservations that other public power entities — namely Bonneville Power Administration — have expressed about joining the EDAM, given CAISO's existing governance structure, in which the grid operator's board is appointed by the governor of California. That arrangement is a no-go for BPA under federal statute if the power marketing agency were to seek the deeper connection of an RTO.

In kicking off BPA's day-ahead market selection process in July, Russ Mantifel, BPA director of market initiatives, said the agency would need to factor in that possible limitation when choosing between EDAM and Markets+. (See *Regulators Propose New Independent Western RTO*.) During Wednesday's roundtable, BPA Administrator John Hairston reinforced that point.

"When we joined EIM, we were really clear," Hairston said. "We came out of our public process and said the governance structure was sufficient but wasn't preferred. The joint authority model [with the CAISO and WEIM boards sharing decisional authority] has worked but, at the end of the day, is not independent, and that's what we're looking for in this next step."

Shetler said RTO participation is not currently "an end goal in and of itself" for BANC members, although they do want to leave open the possibility of getting there."

"I think that EDAM could evolve into an RTO if we wanted it to," he said. "I also think there's the ability that perhaps an RTO could get created and there might be some of us who want to just stay in EDAM and not participate in an RTO. So, I think that optionality is important to us." ■

Forum Turnout, Tone Could Signal Growing Support for EDAM

CAISO Event Draws 240 Attendees, Key Execs As Western Contest Plays Out

By Robert Mullin

LAS VEGAS — The stars may not yet have aligned in favor of CAISO in the contest to bring an organized electricity market to the West, but key players in the industry appeared to be doing just that last week at an ISO event to celebrate the progress of its Extended Day-Ahead Market (EDAM).

Wednesday's EDAM Forum at Resorts World on the Las Vegas Strip attracted 240 in-person attendees and about 300 participants online, a CAISO official said. The packed agenda included a CEO roundtable, a panel of Western utility commissioners, an in-depth presentation on potential EDAM benefits and a discussion about evolving markets in the West.

The ISO convened the forum just a week after CAISO submitted to FERC its EDAM tariff and associated day-ahead market changes designed to increase rewards for flexible resources and reduce load imbalances between the day-ahead and real-time markets. (See *CAISO Files EDAM Proposal with FERC*.)

And, accidentally or not, the event also coincided with two important developments.

The first was a notice issued by the coalition of utility regulators who this summer proposed the creation of a Western RTO that would be independent of CAISO's governance while still building on the ISO's Western Energy Imbalance Market (WEIM) and the EDAM. The document outlined an aggressive timeline for developing the governing framework and seating a board of directors for the new entity, signaling that the backers are moving urgently to build a market structure that ensures the participation of California and increases the likelihood of a single, seamless Western market. (See *Backers of Independent Western RTO Seek to Move Quickly*.)

The second was the Balancing Authority of Northern California's (BANC) announcement that it will advise its publicly owned utility members to join the EDAM over SPP's competing Markets+ day-ahead offering. Accompanying that was a parallel announcement that the board of BANC's largest member, Sacramento Municipal Utility District, approved the utility's request to join the EDAM. (See *BANC Moving to Join CAISO's EDAM*.)

Scott Miller, executive director of the Western Power Trading Forum, expressed surprise at

CAISO said 240 attendees turned out for its EDAM Forum in Las Vegas. | © *RTO Insider LLC*

what he saw at the event.

"This really changes the calculus of my thinking around" Western markets development, Miller told *RTO Insider* immediately after the forum concluded.

"It was the general positivity — even from CEOs whose folks are involved in Markets+ — that struck me as interesting," Miller said later in an email. "The fact that a 'shared governance of EDAM with CAISO' might be acceptable was a bit of a shift, although the shared governance might prove a problem in an RTO setting where transmission operations are turned over to the RTO."

'Tremendous Benefit'

During the CEO roundtable, Pacific Power CEO Stefan Bird explained why the utility's parent, PacifiCorp, the first entity to join the WEIM in 2014, also decided to become the first participant in the EDAM.

"We want to use as much renewable power that's free — has no fuel cost — as much as possible and avoid those emissions," he said.

"I was part of that group running around the West, I don't know, 10-plus years ago, and dreaming about … how cool it would be if we could just coordinate better and be more efficient in how we leverage the abundance that we have across the West, and so proud of how far we've come and excited about the next steps," Bird said.

Idaho Power CEO Lisa Grow offered "profound thanks" to CAISO for developing the EDAM.

"I have been in this industry for 36 years, and I have participated in every single effort we've had to create an RTO, or some sort of organized market, and we just never quite got there," she said. "I think that the demonstration that we can take incremental steps is the only thing that we've seen work."

Grow said the industry's transition to clean energy will require the region to "optimize the system we have." She also questioned whether there's a need for a full RTO — at least in the near term.

Idaho Power doesn't "have legislative or PUC-mandated things that we have to do towards an RTO, so we can kind of watch how this goes," she said.

NV Energy CEO Doug Cannon gave a "shoutout" to CAISO for its responsiveness in developing a WEIM rule change that allows a participant that fails the market's resource sufficiency test during a trading interval to acquire energy within the market rather than just being shut out.

"That's a tremendous benefit," Cannon said. "What we were concerned about is, you've got somebody who's already kind of down. Why are we pushing them further down by not letting them get access to this broader market? Instead, as a West, let's come together and give that person an option to pick [ener-

CAISO/West News

gy] up. Now, they have to carry their weight, they've got to pay the price, but let's help them through that challenging time. And the California ISO came to the table and helped deliver product that really helped there."

Jacob Tetlow, executive vice president of operations at Arizona Public Service, said "this summer has been incredibly challenging for us." The summer featured a 30-day stretch of temperatures exceeding 110 degrees Fahrenheit in Phoenix, leading the utility to smash its previous peak load record of 7,600 MW by nearly 600 MW.

"To me, the Energy Imbalance Market is a very helpful tool. It creates liquidity in the market. It puts resources in that might not have otherwise been available. That's an efficiency gain," Tetlow said.

But Tetlow also cautioned that the WEIM can't be relied on as a resource adequacy tool, given that the market's operations cut some of APS' hour-ahead schedules and low-priority transmission in July.

"So, it absolutely helps, but it can't be the tool to make sure you're resource sufficient for your customers," he said.

"No market is actually a substitute for a solid foundation of resource adequacy," said CAISO CEO Elliot Mainzer. "RA — that's the bottom foundation layer. And that's why it's so important for all of us to be taking those steps to get to solid resource adequacy to meet those planning standards. The market really is an optimization tool."

Mainzer pointed to instances in July and August when it was "kind of hot everywhere" in the West, and the bilateral day-ahead market did not provide enough liquidity to cover all the short positions heading into real time in the WEIM.

While some low-priority exports had to be curtailed, he said, "we were then able to work together to foster maximum liquidity into the hourly markets, and then we were able to sit there and watch the Energy Imbalance Market cycling power across the West, particularly most of it heading certainly not California's direction, [but] at that point in certain places that were really on the edge."

Solving for The 'Future Everything'

Of the CEOs participating in the roundtable, the Bonneville Power Administration's John Hairston was the most reserved in his assessment of CAISO, the WEIM and the EDAM.

While Hairston acknowledged BPA has seen benefits since joining the WEIM in 2022, he also alluded to a running complaint among Northwest hydroelectric producers that the market undervalues the attributes of their resources. He said the agency's portfolio of 31 hydroelectric dams is a "foundational piece to the clean energy transformation" in the West because of its flexibility and lack of greenhouse gas emissions.

"Hydro is highly responsive, so as you add renewables to the resource mix, you're going to have to have that instantaneous response," he said. "And so how we manage the system and reserve it is going to be critically important. And how we also allocate it to markets — participate in markets — will also allow us to figure out how to optimize this incredible resource for attacking climate change and dealing with meeting these renewable portfolio requirements in the most efficient manner."


From left: Lisa Grow, Idaho Power; Stefan Bird, Pacific Power; Doug Cannon, NV Energy | © *RTO Insider LLC*

When BPA this summer embarked on a public process to determine whether to join the EDAM or Markets+, it signaled that its near-term decision on a day-ahead market could hinge on a longer-term evaluation of joining an entity that — unlike CAISO — promises a governance structure that meets the federal agency's statutory requirement for independence. (See *Regulators Propose New Independent Western RTO*.)

"When we joined EIM, we were really clear," Hairston said. "We came out of our public process and said the governance structure was sufficient but wasn't preferred. The joint authority model [with the CAISO and WEIM boards sharing decisional authority] has worked, but at the end of the day is not independent, and that's what we're looking for in this next step."

Hairston said he "applauded" Western regulators for putting out an independent RTO proposal "that has some legs," but said the process will be "complex."

"We need answers now around governance," he said.

"I get that we have unanswered questions," Grow said. "I think we have to be careful not trying to solve for the future everything, because it will collapse under its own weight."

"The governance issue is a tricky one," said Jim Shetler, general manager of BANC, which sits squarely inside CAISO as a separate BA. "I like to say we've lived in the belly of the beast for the last 25 years and we've learned to figure out how to manage that."

"I also like to say I think the ISO today is a very different animal than the ISO 20 years ago. Clearly a much more collaborative organization," Shetler said.

Mainzer attempted to drive that point home in his remarks wrapping up the forum.

"We're just super-motivated to make sure that people feel that they can walk away from a CAISO stakeholder process and say, 'Look, that is really fabulous, and we feel heard, and we feel acknowledged,'" he said.

He also gave a nod to the regulators' RTO proposal, acknowledging that for many Western stakeholders, the "pathway to independent governance is a critical success variable."

"And I'm just appreciative of the work of our regulatory community, to start taking this issue on with seriousness and obviously recognize the importance of getting the right people at the table, open and transparent," he said. ■

CAISO/West News

NV Energy Proposes to Convert Valmy Coal Plant to Gas

Conversion Could Satisfy PUCN Request, Would Almost Halve Carbon Emissions

By Elaine Goodman

NV Energy wants to convert its last coal-fired power plant to a gas-fueled facility, as the utility continues to be plagued with cancellations and delays of planned solar projects.

The proposed conversion of the North Valmy Generating Station is contained in an amendment to the utility's 2021 integrated resource plan. The amendment was filed last week with the Public Utilities Commission of Nevada; PUCN is expected to act on the proposal by Feb. 2, 2024.

The coal-to-gas conversion is meant to satisfy PUCN's request for a "complete solution" for the 522-MW North Valmy coal plant, slated to close at the end of 2025.

NV Energy previously planned to replace capacity lost through the coal-plant closure with two solar-plus-storage projects developed by Primergy Energy — Hot Pot and Iron Point — but those projects fell through.

PUCN then rejected NV Energy's plan for a 200-MW battery energy storage system as a partial solution to the coal-plant closure, saying it wanted to see a comprehensive plan. (See *NV Energy Rejected on Plan to Replace Coal Plant with Storage*.)

NV Energy said the gas conversion will reduce carbon emissions by almost 50% at North Valmy, which is near Battle Mountain in northern Nevada.

"Serving Nevada's rural customers is a critical priority, and the proposed option delivers a reliable and cost-effective option to serve a more remote location that also reduces carbon emissions to respond appropriately to the region's energy demands," NV Energy CEO Doug Cannon said in a statement.

NV Energy and Idaho Power each own half of the North Valmy Generating Station. NV Energy's cost for the coal-to-gas conversion would be $83 million. The utility is asking to run the refueled generating station through 2049.

NV Energy's IRP amendment also proposes building a 400 MW solar project in Northern Nevada with a 400-MW, four-hour battery storage system. The project, called Sierra Solar, would cost $1.5 billion for solar, storage and interconnections.

In addition, the amendment proposes the purchase of development assets for the Crescent Valley solar-plus-storage project for an undisclosed price.

Solar Uncertainty

In arguing previously for approval of its 200-MW battery storage system, NV Energy said supply chain issues had derailed the Hot Pot and Iron Point solar-plus-storage projects.

In last month's filing, the utility said the developer "failed to meet key project milestones" and the build-transfer agreement for Hot Pot and Iron Point had been terminated. PUCN had approved NV Energy's plan to buy Hot Pot and Iron Point from Primergy Solar last year.

In addition, NV Energy said two other solar-plus-storage projects have been canceled: Southern Bighorn and Chuckwalla. Combined with Iron Point and Hot Pot, the four projects would have provided 1,100 MW of solar and 795 MW of battery storage.

NV Energy noted it is negotiating to potentially revive the Southern Bighorn and Chuckwalla projects.

Project delays are another issue. NV Energy said the operation date has been postponed for the Boulder Solar III project, which will provide 128 MW of solar and 58 MW of battery storage.

"Renewable project developers continue to struggle to meet their contractual obligations to the companies to deliver commission-approved renewable projects," NV Energy said in its filing.

Energy Independence

An overarching goal for the IRP amendment is to advance Nevada's energy independence and reduce the state's "exposure to uncertain market resources," the filing states.

"Cause continues to exist to doubt the availability and deliverability of regional market capacity and energy, and therefore, to limit the companies' immediate reliance on it on a going-forward basis," NV Energy said.

The filing takes a "balanced approach" toward energy independence by combining the addition of renewable energy and storage resources with continued operation of natural gas generation, the company said.

NV Energy has been participating in the development of the Western Resource Adequacy Program. And energy independence doesn't rule out participation in an RTO.

"This effort toward energy independence moves in lockstep with expected resource sufficiency requirements of a future market or regional transmission organization," the company said in its filing. ■

NV Energy is proposing to amend its IRP to convert the coal-fired North Valmy plant to natural gas. | *Ken Lund CC-BY-SA-2.0 via Wikipedia Commons*

CAISO/West News

Idaho Power Seeks FERC Help with $700K WEIM Fine

Utility Says Minor Metering Mistake Does Not Warrant Steep Penalty

By James Downing

Idaho Power filed a complaint against CAISO with FERC last week, seeking to get out of $702,425.71 in penalties it was assessed after a metering mistake (*EL23-94*).

The utility wants at least a waiver of the rules because it argued that the minor, inadvertent meter data error should not have been penalized that much, as it had no real impacts on the Western Energy Imbalance Market (WEIM).

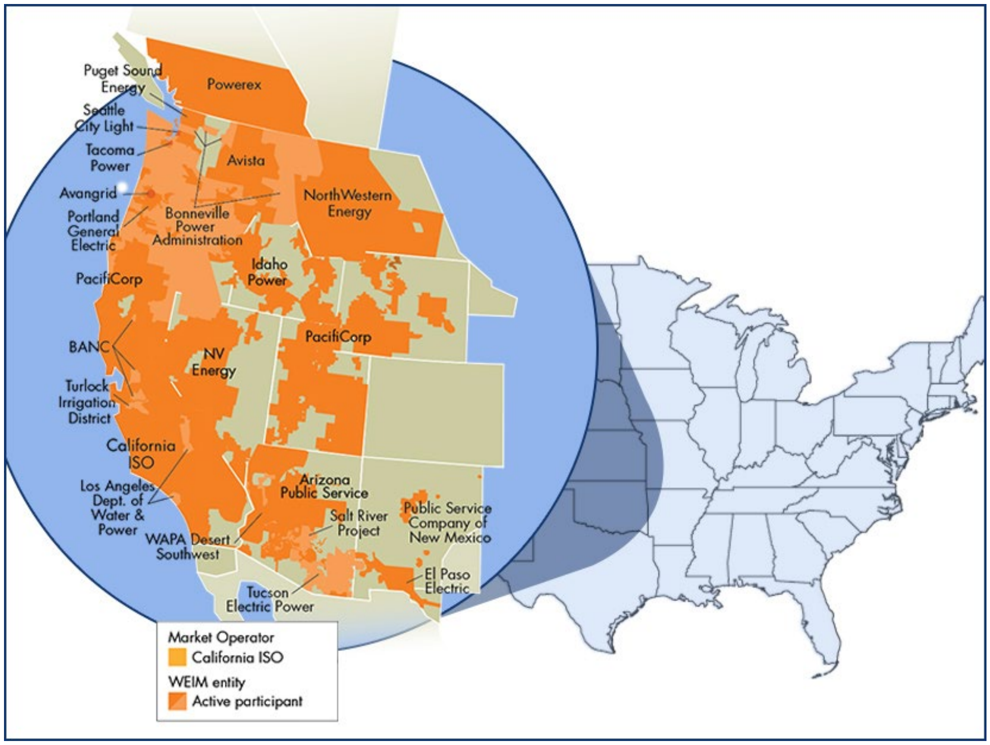
Idaho Power self-reported the meter data inaccuracies around the federally owned Arrowrock Dam, which houses a 19.5-MW hydroelectric facility "that consistently operates below its nameplate capacity," according to the utility. The inadvertent double-counting led to an under-reporting of 0.37 MWh in generation output, which was so small it had no impact on prices, the utility said.

"There were no market impacts resulting from this double-counting of transmission line losses," it told FERC. "In fact, the under-reporting of generation output resulted in energy being produced by Arrowrock without compensation, and the under-reporting led to an increase in energy required by Idaho Power's load from the WEIM that was not needed but was paid for."

Section 37 of CAISO's tariff sets out the penalty rate for such meter data inaccuracies, and the grid operator has no discretion to reduce or choose not to apply the penalty.

CAISO has tried to waive the penalty, but that move was rejected by the commission. FERC has suggested in an earlier order that the ISO should change its rules, and it has a stakeholder process underway, but that has yet to produce a proposal.

The Arrowrock facility does not participate in the WEIM, and Idaho Power dispatches it for native load service. It is connected to Idaho Power's system by several miles of transmission, but the metering takes place near the generator, so line losses must be accounted for.



| CAISO

The utility found out in July 2022 that those line losses were being double-counted since it joined the Western market four years earlier. The error dated back to when Idaho Power was preparing its metering systems for participation in the WEIM.

The utility told FERC the error was difficult to detect and it found out about it only when it was testing the meters and their programming. Idaho Power checked its other meters and determined the issue was limited to Arrowrock.

"The quantity of the data error, 0.37 MWh on average, is small enough that it would not impact the applicable LMP of energy in a material amount had it been reported correctly originally," the firm said. "Importantly, meter data can be corrected after the fact, which does not impact WEIM market runs. The impact of corrected meter data is addressed through settlements after the WEIM market has run."

Despite the lack of impacts, CAISO assessed penalties of just over $700,000. Idaho Power asked FERC for a waiver of that part of its tariff or to grant its complaint that the rules are unjust and unreasonable and should be thrown out.

FERC granted a similar waiver request from NV Energy over a metering error of 1.06 MWh/day that happened when that firm was setting up a new generator. The commission found that NV Energy acted in good faith, notifying the ISO as soon as possible, promptly issued corrective data and confirmed other meters in its footprint were operating correctly.

"These are the same actions that Idaho Power took with respect to Arrowrock," the utility said. ■

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ERCOT News

NERC's DeFontes Calls for Industry Balance

Says Environmental Legislation Squeezing Affordability, Reliability

By Tom Kleckner

AUSTIN, Texas — The Texas Reliability Entity's Board of Directors hosted top NERC official Ken DeFontes during last month's quarterly meeting.

NERC Board of Trustees Chair Ken DeFontes | *© RTO Insider LLC*

Or, as Board Chair Milton Lee said in introducing DeFontes, "Thanks for visiting Texas at the height of summer."

DeFontes, who chairs NERC's Board of Trustees, brought with him the grid's three competing objectives: reliability, affordability and the environment — objectives, he said, that are being thrown out of whack by policymakers focused on environmental legislation.

"I think we've done a really good job over the years of figuring out how to get to that right balance, to do the job economically, to be responsive and attentive to the impact on the environment at the same time," he told the board during its Aug. 23 meeting. "We need to get back to that balance, and part of NERC's job is to better inform policymakers, not only at the federal level but also at the state level because a lot of the impacts are coming from state policy matters."

Part of the answer lies in the agency's biennial reliability risk report. The report, released last week, added engagement in energy policy as one of NERC's five risk profiles. (See *ERO Adds Energy Policy to Risk Priorities List*.)

DeFontes said he and CEO Jim Robb already are making the rounds on Capitol Hill. He said they've been impressed with the level of understanding they've seen from Sen. Joe Manchin (D-W.Va.), chair of the Energy and Natural Resources Committee, and other key legislators.

"That's encouraging to me that there are leaders in Congress who are understanding that as we transition away from dispatchable coal plants and replace them with intermittent renewable resources without a path to get us to whatever the future is going to be," DeFontes said. "Part of the challenge is our message in the short run is manage the transition. Don't lose sight of the fact that we're more dependent on natural gas, so solve the interdependency issue between gas and electricity.

Texas RE CEO Jim Albright (left) and NERC Board of Trustees Chair Ken DeFontes chat before the RE's recent board meeting. | *© RTO Insider LLC*

"The problem with that message is what happens after that. We don't really have an answer."

To help find it, NERC also is conducting an interregional transfer capability study that is due in December 2024, a joint effort with FERC, the regional entities and the industry. NERC *says* the study, a directive from Congress as part of the recent Fiscal Responsibility Act, could provide "important insights for industry, regulators and policymakers."

"I don't think the issue with transmission is a lack of desire or a lack of financing to build it. The issue is getting sited and getting it approved," said DeFontes, who said he has the scars from building transmission dating back to his utility days. "People really don't like to see the transmission lines through their neighborhood. We need to move power across state lines, and when that happens, getting the approval to build the line is complicated, particularly for the states in between ... there's no benefit for them. It comes down to the siting and permitting."

Addressing the Texas RE's board and leadership, DeFontes continued: "I would love to have you help me figure out what we can do to make that work better, but we need more. The rate at which we're investing in transmission right now by all indications is far less than what it needs to be."

ERCOT CEO Pablo Vegas brought a similar reliability message to the meeting. He also focused on the industry's pace of change.

"The systems are becoming complex because of that pace of change and the need for all of us in positions of accountability or various parts of the electric industry to be able to respond," he said, "and to adapt our thinking or methods or technologies or processes in our organizations in ways to be able to take advantage of incredible innovation that's ahead of us and also to be ready for the big challenges that are ahead of us."

At the top of Vegas' to-do list is developing a reliability standard. ERCOT staff have proposed a three-part framework that considers the duration and magnitude of a loss-of-load event, along with the occurrence's frequency. They say this will better quantify LOLE risks when intermittent resources are a large percentage of the generation fleet. (See "ISO Prioritizes Market Changes," *Texas Public Utility Commission Briefs: Aug. 24, 2023*.)

"We're operating at a 1-in-10 standard," Vegas said. "The last time there was a load shed event [before 2021's disastrous winter storm] was 2011. One in 10. Was everybody happy with that? Not even close. There's clearly a lot of opportunities to better define what reliability means, the cost implications and frankly, to be able to have a conversation with constituents."

Using such a conversation as a hypothetical example, Vegas said, "'This is what reliability standard means. This is what you should expect if we were to get into a situation like this because there is no such thing as zero risk. There is no such thing as no contingency.' So let's be upfront. Let's be realistic."

Spaulding to Serve 2nd Term

The Texas RE board's Nominating Committee told directors it's recommending Suzanne Spaulding be approved for a second three-year term as an independent director. The board will consider her nomination during its December meeting.

Spaulding is a senior adviser for Homeland Security at the Center for Strategic and International Studies and a member of the Cyberspace Solarium Commission. She previously was with the Central Intelligence Agency and the Department of Homeland Security, where she was undersecretary for cybersecurity and critical infrastructure protection. ■

ERCOT News

ERCOT Continues to Rely on Voluntary Conservation

Texas Consumers Help Grid Operator Meet Record Demand

By Tom Kleckner

AUSTIN, Texas — ERCOT CEO Pablo Vegas thanked consumers Thursday for helping the grid operator survive tight operating conditions this summer, saying their response to conservation appeals has been "nothing short of tremendous."

"Over the last 10, 11 days, we've asked Texans quite a bit to conserve energy during broad periods of the afternoon and early evenings," Vegas told ERCOT's Board of Directors on Thursday. "We've seen each of the days that we have made those calls a material and meaningful impact on energy demand that has contributed ... to get through a tight period of operations without having to go into emergency operations."

The grid operator has made nine appeals for voluntary conservation this summer, including six times in seven days since Aug. 24. Residential customers are not compensated for their reduction, unlike businesses that participate in demand response programs.

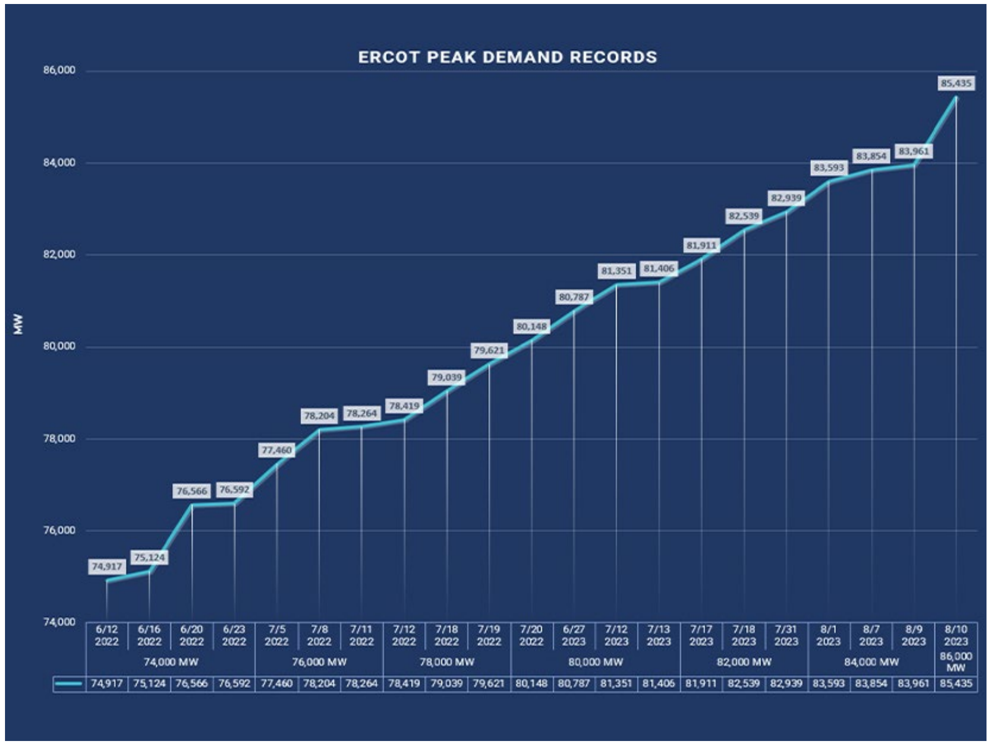
The oppressive heat that has baked Texas since June lessened last week, and demand with it. After recording more than 200 hourly average demand marks of 80 GW this summer, the average peaks have reached only 78.12 GW since Aug. 27.

However, ERCOT still has encountered tight conditions during the early evening, when solar power ramps down and wind resources, which generally contribute less than solar during the summer, try to fill the gap.

The problem last week was with thermal generation units, which have been running full bore this summer. On Wednesday, during ERCOT's latest conservation appeal, thermal outages neared 12 GW, almost a third above what the grid operator terms an "extreme" level.

"We had more thermal outages coming off of a long stretch of very high demand and high utilization," Vegas said. "It's not surprising to see some mechanical breakages happening on some of the dispatchable generation."

He told the board that ERCOT's new normal is managing three primary variables that drive the grid's reliability on any given day: demand on the system, the "traditional" thermal dispatchable fleet's availability and intermittent renewable generation's performance.



ERCOT's peak demand growth over the last two years | *ERCOT*

"The combination of those three contributes meaningfully to whether or not we're going to have enough supply to meet demand," Vegas said. "When you have a challenge with one or even two of those, sometimes things can be tight and we get through it. And if you have issues with all three of them, you can have very tough conditions."

ERCOT CEO Pablo Vegas | *© RTO Insider LLC*

Vegas said that on Aug. 17, operating reserves dwindled to about 600 MW during the evening ramp down. ERCOT resorted to deploying its ancillary services to find extra supplies to meet demand. That included its emergency reserve service, under which participants are paid to take their loads offline.

"What we've been experiencing throughout the summer has been some combinations of those three at different points in time," he said. "That's why it's so critical that we have these tools available to us to manage these very quickly evolving situations and circumstances."

ERCOT has set 10 new all-time peaks as of Aug. 23. The current mark of 85.44 GW, set Aug. 10, still stands. That is a 6.7% increase over last year's peak, a stunning load growth when compared to the industry's normal 1% gain year over year, Vegas said.

"The Texas economy continues to be booming, and this is a great outcome for the state of Texas. It's bringing opportunity; it's bringing jobs ... but it's also bringing demand," he said. "I don't think anybody expects the growth to slow down meaningfully, so we need to be positioned to lean into that and to support that growth as we move forward." ■

ERCOT Board of Directors Briefs

Grid Operator Makes Organizational Changes, Adds COO

AUSTIN, Texas — ERCOT last week announced two leadership changes it said would "sharpen our focus on daily operations" as it battles near-daily tight grid conditions.

The grid operator said in a Friday *press release* that Woody Rickerson, previously vice president of system planning and weatherization, has been promoted to senior vice president and COO. He will be responsible for grid operations, weatherization, planning and commercial operations.

"This new position will leverage Rickerson's deep operations experience and support ERCOT's continued investments in grid innovations," ERCOT CEO Pablo Vegas said in a statement.

Kristi Hobbs, newly named vice president of system planning and weatherization, will handle some of Rickerson's previous responsibilities. She will oversee transmission planning, generator interconnection activities, training and weatherization, and will report directly to Rickerson.

The promotions, both effective immediately, come after ERCOT made six appeals in seven days for voluntary conservation Aug. 24-Aug. 30. The grid operator has recorded 10 all-time peak records this summer. However, it has encountered tight conditions during the early evening, when solar power ramps down and wind resources, which generally contribute less than solar during the summer, try to fill the gap. (See *ERCOT Continues to Rely on Voluntary Conservation*.)

"As our industry faces dynamic changes, ERCOT is continuously evolving and making the necessary improvements to the grid to support the needs of a growing population and robust economy," Vegas said

The announcement came the day after ERCOT's Board of Directors *re-ratified* Rickerson and Hobbs as officers during its bimonthly meeting.

In two other organizational changes, Chief Compliance Officer Betty Day was given oversight of business continuity and Rebecca Zerwas named director of state policy and Public Utility Commission relations and a board liaison.

ERCOT has been operating without a COO since Cheryl Mele left ERCOT and the position in 2019. She now is vice president of customer care and corporate communications at El Paso Electric.

ERCOT COO Woody Rickerson | © *RTO Insider LLC*

NPRR1186 Remanded to TAC

The board remanded back to the Technical Advisory Committee a nodal protocol revision request that has drawn opposition from the storage community.

The directors asked that stakeholders and staff address only unusual scarcity situations raised by Eolian, a storage developer that appealed TAC's approval of *NPRR1186*. Eolian asked that ERCOT be directed to resubmit new NPRRs to determine batteries' state-of-charge (SOC) parameters and related compliance obligations. (See "SOC Transparency," *ERCOT Technical Advisory Committee Briefs: Aug. 22, 2023*.)

Eolian COO Stephanie Smith called for scarcity events to be carefully defined, "ideally with reasonable amounts of study to ensure no further unintended consequences to the market." She said NPRR1186's requirement that batteries meet an SOC obligation at the top of the hour will negatively affect reliability and counter the benefit multi-hour batteries provide.

"We don't yet know whether there will be cost implications to consumers or if it will create grid conditions that lead to reliability concerns or events," Smith said. "Unfortunately, we don't always start at the top of an hour and even though we have hourly products, we don't want all batteries charging at the same time to meet a requirement ... that could lead to unintended consequences, especially during tight conditions."

NPRR1186 also adds definitions and telemetry requirements related to SOC information that date back to 2018 and introduces a requirement that qualified scheduling entities (QSEs) representing an ESR telemeter the next operating hour's ancillary service (AS) resource responsibility. It also specifies that QSEs are expected to manage the SOC to ensure that each ESR has sufficient energy to meet its AS responsibilities and that the day-ahead market process should begin to respect the AS award limits for ESRs based on duration requirements.

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Staff says the measure provides a necessary, cost-effective interim solution to improve the awareness, accounting and monitoring of SOC before the Real-time Co-optimization + Batteries project finishes its work in 2026. As of June 1, ERCOT says there were about 3.3 GW of batteries energized on the system. That total could grow to 9.5 GW by October 2024 should interconnection queue projects with signed agreements and posted security join the grid.

Rickerson and other ERCOT executives said NPRR1186 simply allows them to see how much energy batteries have stored and whether that's enough to meet their commitments.

"We have a reliability issue today ... we want to use batteries. Batteries are the future," Rickerson said. "But we can't keep buying a service that isn't always capable of being delivered. [NPRR1186] will fix that and allow us to get to this power over time."

Vegas: Environmental Regs a Threat

Vegas reviewed for the board five environmental regulations with overlapping timelines that, when taken together, he said could have serious unintended consequences for the grid during peak demand periods.

"Many of these rules do apply to [thermal] resources," he said. "They have to understand whether they comply with one, two, three or combinations. It's a very complex system that could lead to very, very detrimental decisions."

ERCOT's generation fleet is reckoning with five recent regulations from EPA:

- The *coal combustion residuals (CCR) rule* that regulates CCR disposal at inactive generating units and establishes groundwater monitoring, corrective action, closure and post-closure care requirements.
- The *greenhouse gas rule* that proposes significantly lower carbon dioxide emissions for coal and gas units.
- The Clean Air Act's *Good Neighbor Rule* that lowers state-level nitrogen oxides from thermal units to mitigate pollutants to downwind states.
- The *Mercury and Air Toxics Standard* rule that proposes particulate matter emissions standards for coal-fired generators and mercury emissions standards for lignite-fired generators.
- Texas's *regional haze federal implementation plan* that recommends new limits on sulfur dioxide and particulate matter emissions to meet air-visibility requirements at national parks and wilderness areas.

"We all need to keep in mind the compound nature of stacking multiple rules on top of each other because it's pretty deadly when you're the owner and private investment decisions need to be made," board Vice Chair Bill Flores, a former U.S. representative, said. "It's important for the Texas consumer to know that we've got 72 GW, over half of our fleet today, are these plants. These rules take a substantial amount of that offline within the short-term period, and there's no replacement that provides reliable, cost-effective power."

Vegas said ERCOT has filed comments on all five rules and has scheduled a meeting this week with EPA and U.S. Department of Energy "to continue that dialogue."

"We are actively engaging with the Department of Energy and the EPA to make sure that they understand our risks as operators on the system," he said. "We're obviously continuing that dialogue with them so that they clearly understand that it's not just a Texas issue, it's a U.S. issue as the entire grid is transforming."

The Good Neighbor Rule is not effective in Texas, Louisiana and Mississippi after the U.S. 5th Circuit Court of Appeals *issued a stay* in May. The court is not expected to make a final ruling until next year.

San Antonio Tx Projected OK'd

The board approved a $329 million reliability project in the San Antonio area that previously had been endorsed by TAC. The CPS Energy project addresses thermal overloads in South San Antonio and has been designated as a Tier 1 project because of its estimated capital costs of $100 million or more.

In other actions, the board also:

- Authorized the creation of the Technology and Security Committee to provide oversight of technology-related functions and physical and cyber security initiatives and *committee assignments* for the board's members. Director John Swainson will chair the committee, the board's fourth.
- Approved a date change for ERCOT's annual meeting of members to Dec. 18, when the board's committees will meet. The change, from Dec. 19, resolves a conflict with the full board's meeting.

Board Approves 30 Rule Changes

The directors endorsed 30 revisions requests covering the three TAC meetings since the board last met. With the exception of an other binding document revision (*OBDRR048*) that sets two price floors for the operating reserve demand curve (ORDC), they all passed unanimously.

Office of Public Utility Counsel CEO Courtney Hjaltman abstained from voting on OBDRR048, which was opposed by all six members of TAC's consumer segment. The measure adds price adders to the operating reserve demand curve of $20/MWh and $10/MWh that will come into play when operating reserves hit floors of 6,500 MW and 7,000 MW, respectively.

The PUC approved the ORDC revisions, designed as a bridge to the PUC's proposed performance credit mechanism market structure, in August. (See *Texas PUC Approves ERCOT's ORDC Modifications*.)

The board unanimously approved two other OBDRRs, 13 NPRRs, seven changes to the nodal operating guide, two revisions to the planning guide (PGRRs) and the resource registration glossary (RRGRRs) and single modifications to the retail market guide (RMGRR) and verifiable cost manual (VCMRR). They include:

- *NPRR1150*: requires qualified scheduling entities (QSEs) that represent resource entities, emergency response service resources or other QSEs, and that receive or transmit wide-area network (WAN) data to maintain connections to the ERCOT WAN and a secure private network.
- *NPRR1163*, *LPGRR070*: discontinue the process of evaluating interval data recorder meters to determine whether any are weather-sensitive.
- *NPRR1164*: requires resource entities to identify whether a resource has the potential capability, even if unverified, to be called upon or used during a black start emergency or if it has the capability for isochronous control. It also would require resource entities and transmission service providers to identify if a breaker or switch has a synchroscope or synchronism check relay and would define the terms black start-capable resource, isochronous control capable resource, synchroscope and synchronism check relay.
- *NPRR1165*: strengthens market entry eligibility and continued participation requirements for QSEs, congestion revenue right (CRR) account holders and other counterparties by removing minimum capitalization requirements; requiring counterparties to post independent amounts' remove references

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to guarantors; clarifying financial statement requirements; and referencing International Financial Reporting Standards rather than retired International Accounting Standards.

- *NPRR1171*, *NOGRR250*: clarify various reliability requirements for distribution generation resources and distribution energy storage resources seeking qualification to provide ancillary services and/or participate in security constrained economic dispatch (SCED).
- *NPRR1173*: accounts for Texas standard electronic transaction processing options for municipally owned utility or electric cooperative service areas in the protocols.
- *NPRR1174*: establishes a process allowing QSEs or CRR account holders to return overpayment settlement funds to ERCOT.
- *NPRR1175*: strengthens market entry qualification and continued participation requirements for ERCOT counterparties like QSEs and CRR account holders, classifies information in the background check as protected information, modifies application forms for QSEs and CRR account holders, and add a new background check fee to the grid operator's fee schedule.
- *NPRR1176*, *NOGRR252*: revise the Energy Emergency Alert (EEA) procedures to require a declaration of EEA Level 3 when physical responsive capability (PRC) cannot be maintained above 1,500 MW and require ERCOT to shed firm load to recover 1,500 MW of reserves within 30 minutes. The NPRR also would modify the trigger levels for EEA Level 1 and EEA Level 2, change the trigger for ERCOT's consideration of alternative transmission ratings or configurations from advisory to watch when PRC drops below 3,000 MW and restore a frequency trigger for the EEA Level 3 declaration if the steady-state frequency drops below 59.8 Hz for any period of time.
- *NPRR1182*: incorporates controllable load resources and energy storage resources (ESRs) into the constraint competitiveness test's (CCT) long-term and SCED versions. Controllable load resources will not be mitigated but will be used to identify whether a market participant has market power in resolving a transmission constraint; other resources' registration data will be used in the long-term CCT process, and real-time telemetry will be used in the SCED CCT process.
- *NPRR1183*: revises rules for and make publicly available on ERCOT's website general information documents that don't include ERCOT critical energy infrastructure information (ECEII), remove a reference to the Freedom of Information Act from the ECEII's definition and remove antiquated or duplicative language related to reliability must run.
- *NPRR1185*: adds a provision for recovery of a demonstrable financial loss arising from a verbal dispatch instruction to reduce real power output.
- *NPRR1189*: changes *NPRR1136*'s gray-boxed language to align it with existing requirements for ancillary services that resources can provide fast-response service only if awarded regulation service in the day-ahead market for that resource.
- *NOGRR215*: allows new remedial action schemes to address only actual or anticipated violations of transmission security criteria when market tools are insufficient and clarify the procedures for retiring schemes.
- *NOGRR230*: ensures the WAN data transmission's integrity by requiring data be shared in a manner that prevents denial of service and distributed denial-of-service attacks.
- *NOGRR247*: increases the under-frequency load shed (UFLS) program's load-shed stages from three to five and changes the transmission operator load-relief amounts to uniformly increment by 5% for each stage, adds a UFLS minimum time delay of six cycles (0.1 seconds) and adds 59.1 Hz to the list of UFLS stages and revises the gray-box language from *NOGRR226* to provide that the transmission owners' load value used to determine load at each frequency threshold will be the TO's load at the time frequency reaches 59.5 Hz.
- *NOGRR249*: specifies methods for TOs to receive electronic communication of system operating limit exceedances.
- *NOGRR251*: adds cold weather conditions to the template used for developing emergency operations plans to align with *NERC Reliability Standard EOP-011-2* (Emergency Preparedness and Operations).
- *OBDRR045*: edits the demand response data definitions and technical specifications, including modifications to the electric service identifiers list provided to retail electric providers.
- *OBDRR047*: clarifies treatment of unused funds from previous emergency response service standard contract terms.
- *PGRR103*: requires interconnecting entities to complete all conditions for commercial operation of a generation resource or ESR within 180 days of receiving ERCOT's approval for initial synchronization.
- *PGRR108*: updates language to reflect the current practice of posting regional transmission plan and geomagnetic disturbance assessment plans and update data sets.
- *RMGRR174*: updates language to reflect the current practice of posting regional transmission plans and geomagnetic disturbance assessment plans and update data sets.
- *RRGRR033*: adds data to the resource registration glossary pursuant to *NPRR1164*.
- *RRGRR035*: adds data fields consistent with *NPRR1171*.
- *VCMRR034*: provides that actual fuel purchases used to determine the reliability unit commitment guarantee will not be included when calculating fuel adders. ■

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MISO News

MISO Sticks with MW Caps, Higher Fees to Pare Down Queue Requests

By Amanda Durish Cook

CARMEL, Ind. — MISO says it will file in October to put stronger obligations and more monetary risk on queue entry to weed out speculative generation projects and take pressure off its overcrowded interconnection queue.

However, the grid operator has softened elements in its plan to place an annual megawatt limit on project proposals, collect higher entry fees, enact escalating penalty charges and require developers to prove they have land to situate projects on.

"We're getting way too many projects that just aren't ready yet because our rules allow it," Director of Resource Utilization Andy Witmeier said at the Planning Advisory Committee's meeting Wednesday. "We want to make sure we're encouraging viable projects that have done their due diligence, have found land from where they can connect to the system."

Despite that, MISO no longer is proposing an automatic, 73-GW cap (derived from a 60%-of-peak-annual-load) on the total number of new interconnection requests per year. (See *MISO Aims for Manageable Interconnection Queue*.)

Witmeier said MISO believes it still needs caps, but said it likely will pursue less specific, fluctuating megawatt limits year-to-year. Those limits will account for regional and subregional peak load in the study model, an anticipated level of project withdrawals and MISO's "ability to develop a reasonable dispatch" model based on the existing system and proposed generation in a given queue cycle, Witmeier said.

MISO plans to post an annual limit by region on its website ahead of opening queue cycles to developers' submittals.

Witmeier said MISO needs "better, bite-sized sections that we can study more easily." He said MISO has "engineering concerns" that its queue studies don't produce realistic results when they incorporate too many interconnection requests. Witmeier said MISO won't build a dispute process of the annual megawatt limit into its FERC filing.

Stakeholders voiced concerns that FERC would have to blindly accept a megawatt size limit that is subject to change every year.

Clean Grid Alliance's Rhonda Peters argued that the caps should be a temporary measure until MISO can process the queue faster or even allow multiple queue cycles annually.

Witmeier argued that the crux of the issue lies in unprepared projects entering the queue in the first place. He said he hoped a reduced queue leads to speedier processing and that MISO's 70% project dropout rate "goes away" because only higher-quality projects enter.

"Let's implement these and see if we're better able to meet the timelines that we have," Witmeier told stakeholders.

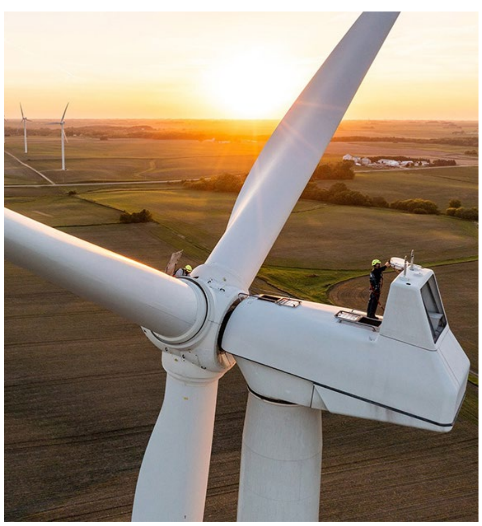
MISO's queue currently contains almost 241 GW across more than 1,400 projects. Its 2022 queue cycle saw 171 GW worth of new entrants clamoring for spots on the grid. MISO hasn't yet closed its 2023 application window because it wants the new rules in place first, so it doesn't risk a queue class as high as 200 GW.

Clean Grid Alliance's Natalie McIntire pointed out that MISO itself has said it will have to carry much more nameplate capacity than peak demand in the future because of the intermittent nature of renewable energy. She said MISO might want to update modeling and dispatch assumptions in its queue studies to contemplate significantly more generation additions.

Witmeier said MISO consistently re-examines its study inputs to make sure they reflect future system needs.

MISO axed a previous provision that would limit the number of megawatts that any one developer can submit per annual cycle.

Witmeier said MISO won't move ahead with the megawatt cap on individual developers because FERC might block it on discriminatory treatment concerns or might see it as stifling competition. He said it may be perceived as a "solution in search of a problem."



| Alliant Energy

MISO also said it will hike its $4,000/MW first milestone fee to $10,000/MW, instead of the originally proposed $12,000/MW.

If FERC accepts even the lowered $10,000/MW, MISO will have the highest entry cost of any other RTO.

Witmeier said the economics of the Inflation Reduction Act "has changed the game," necessitating a higher entry fee to enter MISO's queue.

And that fee increasingly will be at risk of MISO keeping a larger share depending on when a project developer chooses to drop out of the queue. At the first decision point early in the queue study process, a developer will risk 25% of its first milestone payment; that increases to 50% by the second decision point, 75% by the time the project reaches the third and final phase of the queue and finally, 100% if they drop out during the negotiation stage of the generator interconnection agreement (GIA). MISO will disperse the milestone proceeds among lower queued projects that are negatively affected by the withdrawals.

The RTO also will require interconnection customers to secure 100% site control from their generators to the point of interconnection prior to execution of a GIA. However, MISO will grant a 180-day extension from the GIA execution on a case-by-case basis.

Witmeier said MISO views the altered package of rules as "necessary to processing the MISO queue." He said the filing is independent of a future compliance filing in response to FERC's Order 2023.

Invenergy's Sophia Dossin urged MISO to take more time to make sure MISO's stricter queue rules won't interfere with the directives laid out in Order 2023. She said she worried that MISO's proposal "wouldn't pass FERC muster in ways that we can't see."

Witmeier said MISO has examined Order 2023 and has been in communication with FERC staff. He said MISO still believes its best course of action is to file in the fall.

"Because of all the rehearing requests on Order 2023, we can't be sure what the final rule will look like," Witmeier added.

MISO will schedule a special PAC meeting in late September to continue hashing over its proposition. ■

MISO News

FERC Approves Transmission Incentives for MVP Line

Hypothetical Capital Structure, Abandoned Plant, Other Perks Will Help Agency

By James Downing

FERC last week approved transmission incentives for Missouri River Energy Services' share of the Big Stone Project in Minnesota and South Dakota.

The wholesale power agency provides power to 61 member municipalities that own and operate their own distribution systems in Iowa, Minnesota, North Dakota and South Dakota. The MISO member is responsible for two segments of the Big Stone Project, which is a Multi-Value Project approved under the grid operator's 2021 transmission expansion plan.

The first part of the line Missouri River is building is 345 kV and runs about 100 miles from South Dakota into Minnesota along a new right-of-way, while the second part also is 345 kV, but largely will be built on existing rights-of-way in Minnesota. Both segments involve related upgrades to substations, and the firm is working with Otter Tail Power.

Missouri River expects to spend $285.6 million on its half of the project, which will relieve reliability issues on the 230-kV system and improve connections between 345-kV systems.

The power agency asked for and got hypothetical capital structure, construction work in progress and abandoned plant incentives, plus a 50-50 equity and debt capital structure. To implement those incentives, the firm asked for and got some changes to MISO's tariff.

The transmission investment is the largest ever made by Missouri River, representing

| *Ameren*

221% of the $129.5 million of its projected net transmission plan this year and 48% of its long-term debt. Coordinating the line's permitting with multiple owners also will prove to be more complex.

"We find that Missouri River has demonstrated that the requested incentives are tailored to the risks and challenges faced by the Big Stone Project," FERC said. "We also find that the approval of the hypothetical capital structure incentive and CWIP incentive will bolster Missouri River's financial metrics, help ensure maintenance of its current credit rating and enable its participation in the Big Stone Project."

Missouri River asked for the abandoned plant incentive because the project could fail due to no fault of its own, such as negotiations for construction and operations and maintenance agreements between partners with different business models. It also faces regulatory risks as it crosses two states and will require a federal environmental impact statement.

FERC granted the abandoned plant incentive, agreeing that it will help cut the risk of non-recovery of costs in the event the project is abandoned for reasons outside Missouri River's control.

Commissioner Mark Christie filed a concurrence, saying that while the project met FERC's existing requirements for transmission incentives, it was time to examine them generally. Christie has made the same point before on other orders involving transmission incentives.

"As this commission considers other potential reforms related to regional transmission planning and development, it is imperative that incentives like the CWIP incentive, abandoned plant incentive and RTO participation adder are all revisited to ensure that all the costs and risks associated with transmission construction are not unfairly inflicted on consumers while transmission developers and owners stand to gain all the financial reward," Christie said. ■

MISO News

FERC: MISO Can Ban Intermittent Resources from Providing Ramp

By Amanda Durish Cook

MISO has FERC's go-ahead to bar its renewable energy resources from supplying ramping reserves.

FERC's Thursday order leaves MISO's dispatchable intermittent resources (DIRs) ineligible to provide ramping service beginning Sept. 1 (*ER23-1195*). (See *MISO Plans to Bar Intermittent Resources from Ramp Capability*; *MISO Defends Renewable Ramping Stance to FERC*.)

FERC said MISO's plan doesn't amount to undue discrimination because it "currently faces operational and price formation challenges associated with DIRs being unable to deliver ramp capability products services in the vast majority of intervals that DIRs are cleared."

A group of MISO transmission customers argued FERC should have rejected the filing because the ban will treat similarly situated resources differently.

A coalition of MISO's clean energy advocates also protested MISO's plan on the same grounds and said the commission had a duty to reject it because it would create a rate that "unduly discriminate[s] among resources' eligibility to provide grid services." The group also said that MISO is "rapidly approaching an inflection point where it may be economic for renewable generation to maintain headroom in order to provide ramp capability products." They said that prohibiting DIRs from providing ramp service conflicts with "MISO's admitted need for greater flexibility" over the next two decades.

MISO has said its proposal is necessary — at least for now — because of the "significant differences" between renewable and non-renewable resources' ability to deliver ramp product. It said most of DIRs' cleared ramping capability is uneconomic and cannot be delivered because it's trapped behind transmission constraints. The MISO ramp capability product's current design doesn't account for a resource's deliverability.

"Given these conditions, we find that the proposed tariff revisions are just and reasonable and not unduly discriminatory or preferential as they will allow MISO to procure ramp capability products from only those resources that can reliably deliver them," FERC decided.

FERC said that accepting MISO's proposal will put a stop to DIRs being paid for ramp service "even though DIRs cannot reliably deliver the product 99.7% of the time." It also said it will end some market distortion because MISO's market clearing software will be able to clear resources other than DIRs that can provide deliverable ramping.

MISO's Independent Market Monitor agreed that DIRs are "virtually always undeliverable" when scheduled to furnish ramping up capability.

The Monitor said, "ideally, MISO would automatically disqualify any resource from being scheduled to provide ramp capability products when it is not deliverable, but that is not technically feasible for MISO today or in the near future."

In a joint concurrence, Chair Willie Phillips and Commissioner Allison Clements wrote to "emphasize the narrow, fact-bound nature of these decisions."

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Phillips and Clements said FERC's decisions hinges on a "near perfect overlap between DIRs' undeliverability and the circumstances when DIRs would clear ancillary services."

"Today's orders depend upon the particular factual circumstances before us, that unlike non-DIRs, DIRs are highly unlikely to be able to provide ancillary services when they are cleared," the two wrote. They said ramping trends and circumstances could change in the future as MISO adds more renewable energy and advised MISO to improve its markets software so it can account for transmission constraints. ■

MISO News

Latest FERC Order on Grand Gulf Nuclear Plant Ambiguous on Refund Amount

Entergy Defends Actions; Louisiana Officials Fault Entergy

By Amanda Durish Cook

FERC's most recent order on an Entergy subsidiary's tax violations and lease payment collections for the Grand Gulf Nuclear Station in Mississippi reignited a longstanding dispute over how much in refunds should be due to customers.

FERC last week didn't appear to order more refunds stemming from litigation. However, regulators argue FERC's most recent order means Entergy should reimburse ratepayers more than half a billion dollars.

FERC last year ruled that Entergy subsidiary System Energy Resources Inc. (SERI) charged an excessive revenue requirement to ratepayers because it had improperly excluded accumulated deferred income tax (ADIT) deductions since 2004. Those deductions are related to the future estimated decommissioning expenses for Grand Gulf that Entergy claimed on its consolidated federal income tax return. Entergy claims it's already taken care of the matter by crediting about $100 million to customers.

The newest order on Grand Gulf matters, issued Aug. 28, doesn't clear up exactly how much Entergy owes for the tax violations, though it rehashes longstanding disagreements over Grand Gulf accounting practices (*EL18-152*). FERC restated that SERI "must refund amounts resulting from the improper exclusion of ADIT liabilities from the [unit-power sales agreement] rate base."

FERC also decided last year that SERI must refund ratepayers about $149 million plus interest for overbilling on the Grand Gulf annual lease payments it collected from Entergy companies from 2015 through 2022. Last week's order allows Entergy to offset the undepreciated remaining book value of the sale/leaseback property, letting it partly recover some of that amount.

The Louisiana Public Service Commission and New Orleans City Council maintain Entergy owes roughly $550 million in refunds split between ratepayers in Louisiana, Arkansas and New Orleans. (See *Regulators File Emergency Motion in Ongoing Grand Gulf Battle*.)

SERI operates and owns 90% of the 1,400-MW Grand Gulf plant in Port Gibson, Miss. It sells the plant's output to Entergy's Arkansas, Louisiana, Mississippi and New Orleans affiliates under a unit-power sales agreement (UPSA) that includes the costs of the Grand Gulf Nuclear Power Station's sale-leaseback renewals.

In a press release, Entergy said its actions "have been and continue to be in the best interest of its customers." It also encouraged the state regulators and city councilors to consider accepting a settlement related to the remaining litigation involving Grand Gulf performance issues and accounting practices. (See *Entergy Offers Regulators $588M to End Grand Gulf Complaints*.)

"We are pleased today's order resolves a major source of litigation between our regulators and SERI," said Rod West, Entergy group president of utility operations. "We hope the clarity provided by the FERC in this ruling helps to guide constructive discussions with our regulators to resolve the remaining SERI litigation matters. A comprehensive settlement could provide significant and imminent refunds to our customers at a time when energy bills are high due to record usage."

New Orleans City Council Vice President Helena Moreno *called* Entergy's reading of the order and the utility's claim it doesn't owe further refunds "bizarre."

The Louisiana Public Service Commission also said it *disagreed* with Entergy's interpretation.

"The FERC order confirms that SERI does owe refunds, contrary to Entergy's assertions. FERC denied SERI's request for rehearing of the refund issue. Entergy's public statement provides no FERC language alleged to support its position," the Louisiana PSC said in the release. The state commission also predicted more litigation.

Louisiana PSC Vice Chair Mike Francis vowed

Grand Gulf Nuclear Station | *Entergy*

to fight for more refunds.

"It's time for Entergy Corp. to stop these legal challenges and comply with the order to refund what is owed to our people. The time is now to bring the matter to rest," Louisiana PSC Commissioner Davante Lewis said.

Despite the murky refund issue, FERC's order contained myriad decisions on rehearing. It said though Entergy defended its accounting treatment of Grand Gulf's lease renewal, it remains inappropriate for SERI to have handled the renewal as a financing extension of the original sale-leaseback agreement that lasted from 1989 to 2015. The lease renewal from 2015 onward should have been considered standalone, FERC said.

The commission reaffirmed that the lease renewal "was not simply an extension of the original sale-leaseback under the terms of that agreement, pursuant to, for example, an evergreen clause," but a separate transaction using "new lease instruments that memorialized a new lease term, as well as the amounts and frequency of new rental payments."

FERC also asserted that it was wrong of SERI to attempt to recover the costs of a return on net capital additions through both its rate base and the lease renewal payments because it constitutes a double recovery.

Additionally, FERC directed SERI to transfer and reclassify $147.3 million of excess ADIT associated with nuclear decommissioning tax deductions to a property-related ADIT account.

Tiff Arises over ALJ Authority

Lastly, FERC rejected SERI's argument on rehearing that it shouldn't have allowed an administrative law judge to conduct the hearing and issue an initial decision in the Grand Gulf sale-leaseback and tax disputes. SERI had surprisingly alleged that "proceedings before an administrative law judge are unconstitutionally insulated from the president's control by multiple layers of removal protections." It said such judge's decisions are invalid because they are unconstitutionally appointed by the FERC chair alone.

FERC Commissioner Mark Christie said he was taken aback that SERI raised a constitutional issue so late and in a rehearing request. He wrote separately to second FERC's rejection of Entergy's argument and admonish SERI for throwing a curveball so late in the game "in only a few pages buried near the end of its rehearing request."

"A constitutional issue of this magnitude is not one that is appropriate to raise for the first time on rehearing. It should have been raised and fully briefed well before this point in the process and — preferably in my view — set down for oral argument before the full commission, before any final determination by this commission would be rendered," Christie wrote. "Ideally, a constitutional issue of this magnitude should be raised only in a general proceeding where all interested parties can weigh in extensively."

It was FERC's defense of the use of an administrative law judge in this case that had Commissioner James Danly tacking a dissent onto the order. He said FERC's argument that it can use an after-the-fact ratification of an administrative law judge's appointment in a docket or a full commission review and adoption of an administrative law judge's findings to remedy a possible constitutional infirmity was legally flawed. ■

MISO News

FERC Approves Lower MISO Reliability Payments to Ameren Coal Plant

Original $9.3 Million Payments Reduced to $8.3 Million

FERC last week approved a settlement to reduce payments to a Missouri coal plant under its system support resource (SSR) agreement with MISO.

The commission accepted a trimmed-down, $8.3 million monthly payment to keep the two-unit Rush Island Energy Center operating (*ER22-2721*). The new amount brings the total annual Rush Island SSR revenue requirement to almost $100 million.

MISO last year deferred Ameren Missouri's planned retirement of its 1.2-GW Rush Island plant to keep the grid reliable. Ameren originally proposed a $9.3 million monthly SSR payment as part of the deal, but FERC at the time warned that amount might be too high. (See *FERC: Rush Island Plant's Extension Essential to MISO Reliability*.)

Ameren offered the lowered amount in a settlement agreement in May. FERC said the settlement appeared to be fair and in the public interest.

Ameren's Rush Island coal plant in Missouri | *Ameren Missouri*

In early summer, MISO said it likely will require the assistance of Rush Island for about two more years to avert reliability issues until members complete transmission upgrades and bring wind, solar and battery storage projects proposed in Illinois and Missouri online. The RTO plans to renew the SSR for another year beginning Sept. 1, and once more in 2024. (See *MISO Poised to Extend Missouri Coal Plant's Life*.) ■

— Amanda Durish Cook

MISO News

Minnesota PUC Mulls Lifting Ban on Aggregated DR in Wholesale Markets

Stakeholders Weigh in with Multiple Concerns

By Amanda Durish Cook

Minnesota regulators last month discussed whether it's time to allow aggregators of retail customers to bid demand response into wholesale markets.

The Minnesota Public Utilities Commission weighed a decision to lift its 13-year-old ban on the practice at its Aug. 24 meeting (*E999/CI-22-600*). The commission also considered whether to direct its utilities to develop tariffs to allow third-party aggregators to participate in utility demand response programs, how it might verify or certify aggregators of retail customers for demand response or distributed energy resources before they are permitted to operate, and whether allowing aggregators to operate will require it to establish additional consumer protections.

Minnesota's regulated utilities said a decision to lift the 2010 ban would be unwise, while commissioners and aggregators said it could move the needle on the sluggish amounts of demand response in the state and leave it better prepared for the clean energy transition.

The commissioners ultimately didn't vote on removing the ban, instead tabling the docket, though they promised more exploration on demand response going forward.

Otter Tail Power's Cary Stephenson said he opposes lifting the ban. He said his utility already has made major investments to grow its own successful demand response programs. Stephenson said Otter Tail backs a structure where demand response is treated as a fully regulated program in a utility model.

"In our view, it's not in the public interest to introduce [aggregators of retail customers] into that structure. … Customer confusion is one of our big concerns [and] cannibalization of the existing DR programs which have worked very well," he said.

Stephenson predicted "significant administrative costs" associated with utilities coordinating with aggregators.

"Overall … we think there are significant material downsides," he said.

Stephenson also said it's premature for the PUC to decide on aggregation before FERC has issued an order in MISO's Order 2222 compliance plan, which will open its wholesale markets to aggregators of distributed energy resources.

Flint Hills Resources' Pine Bend refinery near Minneapolis participates in Xcel Energy's DR program. | *Forrest Pearson*

Minnesota Power's David Moeller said aggregators could erode the state's legal definition of service territories and the state's authority to require tariffs. He said he wasn't sure if the commission had the authority to force regulated utilities to file tariffs for noncustomers to incorporate aggregator participation, which would undercut their own DR offerings.

Xcel Energy's Ian Dobson said his utility is working to achieve the state's 2017 directive for Xcel to add 400 MW of additional demand response to its existing, 1,000-MW program. Dobson said to date, Xcel has added a net 170 MW in demand response after it lost some subscribed load.

Xcel Energy's failure to meet the commission's 400-MW additional demand response goal set in 2017 sparked the PUC's discussion on unraveling the aggregator ban.

"We understand, obviously, the reasoning behind wanting to see if aggregators can help as well. … Our concern is just wanting to make sure that however the commission wants to go with this … that it provides the most benefit for our customers," Dobson said.

Commissioner Matt Schuerger said evidence in recent commission dockets shows Minnesota doesn't have the robust DR program utility executives described. Schuerger said Xcel repeatedly has missed the mark and could have increased DR capacity by 1,000 MW by now. He said there is "lots available we're not accessing."

Schuerger said the 400 MW DR target "was a low bar in 2016."

Commission Chair Katie Sieben asked whether Xcel is planning to include virtual power plants as a resource when it files its next integrated resource plan in February.

Dobson said he wasn't sure.

"There's a degree, I think of frustration, that is bubbling up out of me. We're in this position — all of the utilities — because Xcel hasn't quite met the standards that were imposed on the company from the 2017 IRP," Sieben said. She said maybe the commission's frustration with Xcel Energy not doing enough on the demand response front should be handled in the utility's upcoming IRP filing, and not handled by blowing up a prohibition on third-party aggregation that could "seemingly disrupt a lot

MISO News

of apples on the apple cart."

Dan Lipschultz, representing the Minnesota Rural Electric Association, said commissioners should wait a few years to see whether utilities sufficiently expand their DR offerings. He said if they're not satisfied, they can always take the more drastic step of rescinding the aggregator ban.

"When we look at the need for and the value of demand response, it's really important that we don't use the rearview mirror and use a standard of what was needed 10 or 20 or even five years ago," Schuerger said. "We're accelerating this energy transition that we're in; the Legislature has laid out clear guidance that we're going to go even faster than the fast pace that we're already moving."

Schuerger said advance demand response is not just emergency use or peak shaving and is critical moving forward.

"I'm hopeful that we'll keep this door open. I think that we've got to explore all avenues, all hands on deck, all tools available to get the load flexibility and the demand response that the math is showing us we're going to need," he said.

Commissioner Joseph Sullivan said he also viewed demand response as "more than just an emergency resource." He said DR programs could do more and that there are innovative companies developing products that "quite frankly, utilities haven't really thought about." Sullivan said he wasn't sure that permitting aggregators to operate would be much different from Minnesota's decades-old decision to allow utilities to source from independent power producers.

"Isn't this just another entity that can bid into the utility platform so it's not fundamentally a breach of the compact? It's just the market has evolved and it's transforming?" he asked.

Matt Schuerger, Minnesota PUC | *NARUC*

Utility representatives said the fundamental difference hinged on that independent power producers enter into power purchase agreements with utilities, and don't contract directly with customers.

Sullivan said the commission could create a model with tariffs and oversight for third-party aggregators. He also pointed out that aggregators of retail customers in the wholesale market would have to operate under the boundaries of the MISO tariff.

"It's not a free-for-all. It's not the Wild, Wild West," Sullivan said.

Lipschultz said the MISO tariff doesn't account for Minnesota policies or equality and protecting the public interest.

Jon Wellinghoff, former FERC commissioner and chief regulatory officer at Voltus, testified in favor of lifting the ban. He said it would put pressure on Minnesota utilities and the larger MISO footprint to lower rates.

Wellinghoff said it makes sense the utilities, as competitors in a wholesale market, would try to dissuade commissioners from a repeal to retain their monopolies.

"We're not talking about retail services. We're not talking about upsetting the regulatory compact at the retail level. It has nothing to do with that. At all. Nothing whatsoever," he said. "We're not talking about a monopoly retail service. We're talking about competitive wholesale programs."

Wellinghoff said aggregators behave exactly like merchant generation in the wholesale markets. He also said it's clear FERC for years has wanted demand response participation in wholesale markets.

Ingrid Bjorklund, speaking on behalf of the Advanced Energy Management Alliance, said the time is right to allow aggregators in the wholesale market.

"So much has changed since 2010, when this issue was last revisited," she said. "More and more flexible resources are going to be needed as we move towards the clean energy economy and clean energy future, and allowing nonutility aggregators of demand response on both the wholesale and retail levels is really necessary to get there."

Bjorklund said the administrative costs of allowing aggregators participation are "de minimis" and will be far outweighed by customer savings. She also said the Advanced Energy Management Alliance would support the commission sunsetting the ban at a future date.

Sarah Johnson Phillips, representing several large industrial customers in Minnesota, said mines, mills and factories have been trying for years to convince regulators to undo the 2010 order. ■

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NYISO Proposes $41.62M Project Budget for 2024

ISO Reports on July Operations at MC; Stakeholders Approve Capital Fund Rebalance Change

By John Norris

NYISO faced stakeholder scrutiny Wednesday after presenting its final project budget recommendations for next year to the Budget and Priorities Working Group, amounting to an estimated $41.62 million total.

The ISO is proposing 29 market and 37 enterprise project candidates. Although the total is fewer than was suggested when NYISO last shared the proposed budget, it is still about 30% higher than this year's.

Labor costs are the primary driver behind the budget's increase, rising from $13.74 million this year to an estimated $18.03 million.

Kevin Lang, partner at Couch White, expressed concerns about the hike, asking how the ISO planned to mitigate rising costs and whether it had the bandwidth to manage the projects or would require help from outside consultants.

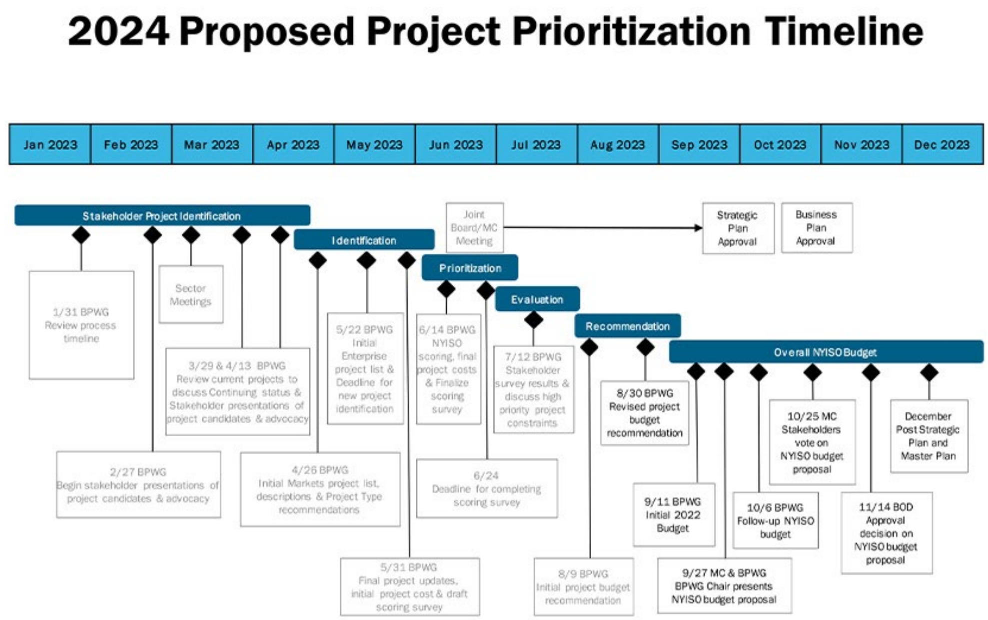
"I recognize that some of these [projects] are relatively small and some will be a larger effort, but there are many more projects here than you had in the last few years," Lang said.

Kevin Pytel, senior manager of product and project management at NYISO, conveyed confidence, saying, "We are comfortable with the workload; it is a lot, and we're awfully stretching ourselves, but we do feel like it is achievable."

Lang next asked how NYISO planned to reduce the cost of future budgets.

NYISO CFO Cheryl Hussey told Lang that "to address the increase in the cost of the product portfolio for next year, we'll be proposing to increase our level of financing by $10 million in 2024," a request that is under review by the New York Public Service Commission.

Pytel committed to a project prioritization process re-evaluation this fall, aiming for collaborative discussion on potential enhancements. Feedback on the proposed budget or the prioritization process can be sent to kpytel@nyiso.com.



Timeline of NYISO's proposed project priorities for 2024 | *NYISO*

The proposed budget will be revisited at the BPWG meeting Sept. 11, and NYISO aims to obtain budget approval at the Management Committee meeting Sept. 27.

July Operations Report

NYISO CEO Rich Dewey reported to the MC meeting, which also was held Wednesday, that it had been a "cool, long and wet summer" that saw much lower monthly energy prices compared to last year.

NYISO COO Rick Gonzales said the summer's peak load of 28,735 MW came July 28, noting how August has been particularly mild so far. Additionally, 20 MW of nameplate front-of-meter solar resources were added since June. (See *NYISO Operating Committee Briefs: July 22, 2023*.)

Working Capital Fund Rebalance

The MC also voted to recommend that NYISO's proposed revisions to how it rebalances customer contributions to its working capital fund be approved by the Board of Directors.

Every January, NYISO calculates each customer's contribution to the fund based on the previous year and issues refunds that include interest in February. The ISO wants to rebalance the fund twice a year, in January and July, based on the prior six months. The rebalancing would better reflect recent conditions, and customers would receive refunds more quickly, it said.

The Business Issues Committee has already endorsed the proposal, and the ISO plans to present it to the board for Oct. 16. (See "Working Capital Fund Rebalance," *NYISO Business Issues Committee Briefs: Aug. 16, 2023*.) If greenlit, the revisions will be implemented starting in July 2024. ■

	Estimated Cost (in millions)					
Project Budget*	Labor	Capital	Prof. Serv.	Total	Mandatory	Continuing
2024 Final Recommendation	18.03	9.70	13.89	41.62	5.82	4.16
2023 Approved	13.74	9.72	8.51	31.98	5.58	10.37
2022 Approved	13.36	12.48	11.35	37.20	11.56	1.18
2021 Approved	11.58	5.92	9.02	26.52	7.58	14.15

Breakdown of NYISO's proposed budget for next year compared to previous years | *NYISO*

NYISO News

NYSERDA Backs Inflation Adjustments for Renewable Projects

Developers Say Inflation Has Rendered Some Contracts Untenable

By John Cropley

The lead agency in New York's clean energy transition has come out in favor of inflation adjustments for renewable projects under contract but not yet under construction.

Inflation and interest rate hikes have emerged as a significant threat to the state's statutory emissions-reduction goals, as developers of 91 projects totaling 13.5 GW of capacity are seeing construction costs soar. Some are saying they may not be able to proceed under terms negotiated, and three petitions representing numerous developers were submitted to the state Public Service Commission in June seeking relief.

More recent solicitations by the state have offered adjustment mechanisms to account for cost changes, but the solicitations these developers bid into did not.

A flurry of comments was submitted Aug. 28, the PSC's deadline for input in *Case 15-E-0302*.

The sentiment fell largely along predictable lines: Those who are fighting for decarbonization and those who would profit from it favored a retroactive boost for the earlier contracts. Opposition came from those who would pay for it or fear they would lose a competitive edge because of it.

The New York State Energy Research and Development Authority submitted a lengthy analysis of options, costs, benefits and risks and concluded that a price adjustment could help maintain New York's forward momentum toward the goals of the Climate Leadership and Community Protection Act (CLCPA), which requires renewable power make up 70% of the state's generation mix by 2030.

If developers walk away from their contracts to provide it, the state will have to seek new contracts; bids will inevitably come in higher, perhaps higher than the adjustments the current contract holders seek. These new contracts inevitably will take longer to complete, and the delay will prolong the damaging effects of greenhouse gas emissions generated by burning fossil fuel.

NYSERDA said bid prices submitted in the latest solicitations are significantly higher than those in the earlier contracts.

Work on the Champlain Hudson Power Express near Lake Champlain recently | *NYSERDA*

More Money

Developers of nearly all of New York's offshore wind portfolio and much of the onshore wind and solar pipeline sought relief through similar petitions submitted to the PSC on the same day in June.

Soon after, Clean Path New York — an $11 billion portfolio of wind and solar projects with an underground transmission line to carry the power they generate to New York City — said it needed the same adjustment if the PSC grants it to the Tier 1 generation projects. Two-thirds of its generation portfolio is Tier 1, so Clean Path would be paying them more.

Another shoe dropped last week: The Champlain Hudson Power Express asked the PSC in a petition Aug. 28 to level the playing field and make any inflation-related price adjustment apply to all new-build project components.

The underground HVDC line to carry emissions-free power from Quebec hydropower plants to New York City was first proposed in 2010. Early cost estimates were in the $2 billion range, but the PSC in 2022 authorized up to $6 billion in debt to build it. Construction began this year.

Champlain Hudson said in its petition it has suffered the same unforeseeable cost increases as everyone else, mentioning a converter station whose cost jumped 40% in less than a year. The adjustments it is seeking would not make it whole, it said, and would mean only a modest increase in costs.

A spokesperson for developer TDI told *NetZero Insider* the issue is one of fairness: Any inflation relief must be extended equally to all participants in the state's renewable energy certificate (REC) program. "CHPE's petition reflects the necessity that large-scale renewable developers who participated in competitive NYSERDA solicitations and have all faced the same economic and geopolitical challenges are treated equally," it said.

Reactions

Comments ranged from hundreds of the same supportive message from individual members of unions that expect to work on clean energy projects, to NYISO, which has warned of potential shortfalls in generation capacity amid the transition.

The ISO took no position on whether or how

NYISO News

the REC agreements should be modified. Instead, it emphasized the importance of continued progress in the buildout. If development of renewables is not "rationally coordinated" with retirement of fossil fuel resources, system reliability is jeopardized.

As NYSERDA and others commented, losing the existing contracts would slow progress.

NYISO already has identified a potential deficiency of up to 446 MW in New York City on peak summer days, and its warnings about the slow pace of the state's energy transition have grown increasingly firm in recent months.

In its comment to the PSC, NYISO wrote: "A sufficient fleet of new generation resources that satisfy the CLCPA must be available before more of the existing, traditional generators retire voluntarily or are forced out of service."

The Public Utility Law Project of New York laid out a different set of priorities: a consistent and transparent review of the developers' requests for more money, and an effort to cushion ratepayers from the impact of any increase.

"We strongly believe that ratepayers, especially those who are low-income or who live in disadvantaged communities, cannot and should not be left to shoulder the financial burden, especially unexpected cost adjustments," it wrote.

The state Department of State's Utility Intervention Unit came out in opposition to the increase.

"For markets and competition to function efficiently, contracts and obligations should be honored," it wrote. "Altering contracts after terms are defined can diminish the competitive process that potentially disadvantages those bidders not selected in a respective solicitation and consumers who are paying for the project."

The unit also urged that the PSC scrutinize each project's costs carefully, and that it limit any adjustment mechanism to those projects more likely to succeed: "Ratepayers should not be throwing good money after potentially bad projects."

New Yorkers for Clean Power urged the adjustment be granted, as the projects in question are critical for not only meeting the CLCPA's goals, but also boosting the state's economy. "The petition demonstrates that failing to redress the economic circumstances will result in both years of material delay and substantial additional cost," it wrote.

Offshore wind developer Rise Light & Power dismissed the idea of giving other offshore wind developers more money than they agreed to. "It is unprecedented and unwarranted to ask the commission to direct NYSERDA to change *ex post facto* the most material terms of a competitively bid contract to benefit a petitioner and increase the cost and risk of such contract to NYSERDA."

Rise had a similarly dim view of the onshore wind and solar petition, saying an increase would be "unfair to prior and current bidders in Tier 1 solicitations, harmful to ratepayers and would violate bedrock principles of competitive public contracting."

The New York City Mayor's Office of Climate and Environmental Justice led off with a pointed observation: The process is already too slow. Since 2016, NYSERDA has entered into 115 contracts totaling 13,730 MW of renewable generation and storage, it wrote. But only 14 of those projects have come online, delivering just 681 MW.

For this reason, the city endorsed relief for renewable developers, though not as much as was requested, because of the likely effect on ratepayers. "There is much work to do, and time is of the essence to achieve the state's 2030 goal," it said.

Nucor Steel Auburn — whose electric arc furnace is one of the largest loads on the New York State Electric & Gas system — blasted the request for an inflation adjustment for the Tier 1 onshore contracts as unsubstantiated, unjust and not in the public interest. It wrote: "The added cost to New York consumers from such a measure would approach $10 billion over the 20-year life of REC contracts."

New York's investor-owned utilities, commenting jointly, made a similar point, warning of billions in extra costs for ratepayers. "These petitions, if approved without modification, would create a perverse incentive and weaken the effectiveness of future NYSERDA REC contracting cycles and create unnecessary costs for customers throughout New York state," they said.

The Sierra Club and Environmental Advocates of New York backed the idea of inflation adjustments weighed with impact on consumers, the market and the environment.

"While we do not endorse any particular level of support for contracted at-risk renewable energy projects, an inflation adjustment of the type requested by petitioners should be strongly considered as part of a least-cost approach to achieving New York's renewable energy commitments." ■

PJM News

PJM Presents Preliminary 2023 Reserve Requirement Study to Stakeholders

Study Sets Installed Reserve Margin, Resets Figures Going Back Three Years

By Devin Leith-Yessian

Reserve margins would increase significantly based on the preliminary 2023 Reserve Requirement Study (RRS) results PJM *presented* to the Resource Adequacy Analysis Subcommittee (RAAS) on Aug. 29.

The installed reserve margin (IRM), which sets the targeted capacity level above expected loads, would rise from 14.7% for the 2026/27 delivery year (DY) in the 2022 study to 17.6% for the 2027/28 DY using PRISM modeling software. The forecast pool requirement, which considers forced outage rates, also would increase from 9.18% to 11.65% for the corresponding DYs.

When comparing RRS results, PJM looks at the furthest year out, as that would be the year a Base Residual Auction (BRA) would be run under a three-year advance auction schedule. (See "Stakeholders Endorse 2022 Reserve Requirement Study Results," *PJM PC/TEAC Briefs: Oct. 4, 2022*.)

This year's study also engages in a second analysis using software developed to perform hourly loss-of-load modeling used in effective load-carrying capability (ELCC) studies to calculate the IRM and FPR. Both results will be presented to stakeholders, who will be asked to endorse one of the sets of results.

The hourly analysis yielded an IRM of 18.3% for the 2027/28 DY and 12.31% FPR, with much of the difference between the PRISM values arising from the load model.

In addition to setting an initial IRM and FPR value for the 2027/28 DY, the study resets the figures for the previous three years. The preliminary results would be increased by a similar margin for each of those years.

PJM's Patricio Rocha Garrido said the drivers of the higher margins in the preliminary results are increased uncertainty in the peak load forecasts in the data and a higher generation forced outage rate in the winter owing to the December 2022 winter storm and the 2013/14 polar vortex being included in the data. Shifting to hourly modeling of peaks also increased the expected peaks.

Minimal coincidence between the PJM peak load period and the "world" peak — which is defined as MISO, NYISO, TVA and VACAR — led to the capacity benefit of ties (CBOT) value more than doubling to 2.2% from the 1% value in the 2022 study. To reduce volatility, PJM elected to average the CBOT values from 2017-22 and use that figure, which landed at 1.5%, instead.

While the RTO opted to shift the world peak to not fall on the same week as PJM's peak in the load model, spokesperson Jeff Shields noted that a similar shift was made last year. (See "Stakeholders Endorse RRS Load Model," *PJM PC/TEAC Briefs: Aug. 8, 2023*.)

"So, shifting the world peak week is not the whole story — the peak load coincidence in weeks other than the PJM peak week, as well as the magnitude of the world peaks on those weeks (as well as during the PJM peak week), also play an important role," Shields said in an email.

The load model, which included data from 2013-2019, contributed to a 2.1-percentage-point increase in the IRM, while the winter peak week caused a 1.1-percentage-point increase under the PRISM modeling. The values were slightly lower for the FPR drivers.

The CBOT contributed to a 0.5-percentage-point decline in the IRM value and 0.58-point-lower FPR.

Under the hourly analysis, the load model contributed to a 3.1-point increase in the IRM and 2.95-point increase in the FPR. The winter peak week increased the IRM by 0.7 points and the FPR by 0.66 points. The CBOT lowered the IRM by 0.5 points, which was about the same for the FPR.

The non-winter peak week had a smaller impact on the IRM under both approaches, 0.2 under PRISM and 0.3 in the hourly model, and had no contribution to the FPR. PJM used a larger amount of data to determine the expected winter peak capacity models, drawing on aggregate outage data from the 2007/08 DY through 2022/23. The remainder of the capacity model data used Generating Availability Data System (GADS) outages from 2018-2022.

Rocha Garrido said PJM is in the process of using coincidental peak distributions to calculate additional values to compare to the PRISM and hourly results to inform staff's recommendation of which model to use in the final study results.

James Wilson, a consultant to state consumer advocates, said he calculated the PRISM values would lead to around a 3,700-MW increase in the summer reserve margin. Rocha Garrido agreed that likely would be about right. Wilson questioned what has changed about PJM's understanding of resource adequacy in the summer to drive such an increase in the amount of capacity that would be procured.

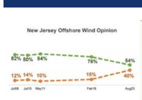
"The explanations just say we made a bunch of changes. … Why are we buying a lot more when we don't have any reason to think the same isn't enough?" Wilson said.

PJM's Andrew Gledhill said staff worked with Itron to improve their load forecast modeling, leading to the hourly approach and an overall modeling that they believe has a tighter fit to the data available. The old modeling appeared to be underforecasting load certainty, in the winter in particular.

Wilson said PJM historically had not included data from the polar vortex in its modeling, believing the issues that led to high forced outage rates during the event had been addressed by winterization efforts. He called on PJM to provide additional analysis justifying the data's inclusion in the RRS, saying PJM had relied only on the impact of Winter Storm Elliott to make that change.

First reads of the IRM and FPR values are scheduled for this month's Planning Committee and Markets and Reliability Committee meetings. The PC is expected to vote on endorsement the following month, while the MRC and Members Committee are anticipated to vote October through November. The values are expected to be presented to the Board of Managers in December. ■

Mid-Atlantic news from our other channels



Poll Shows Drop in Support for Offshore Wind in NJ

NetZero Insider

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

Southeast

TVA Resists Congressional Call to Achieve 100% Clean Energy Sooner

TVA Touts Progress, Notes Out-of-territory Concerns

By Amanda Durish Cook

The Tennessee Valley Authority does not appear ready to fast-track its decarbonization plans despite receiving a *letter* last month from 10 members of Congress urging it to chart a path to 100% clean energy by 2035.

The legislators asked TVA to decarbonize 15 years faster than it is currently planning, telling the utility it has a duty to "thoughtfully re-evaluate and further develop TVA's long-term energy and decarbonization strategies" through its upcoming integrated resource plan and its ongoing Valley Pathways Decarbonization Study. It is disconcerting that TVA has the second-highest planned natural gas buildout of all major U.S. utilities, they said.

"As the country's largest public power producer, the Tennessee Valley Authority should be leading the nation's transition to a clean, renewable energy future, not dragging its feet," the group of senators and representatives wrote. "Yet TVA continues to rely on fossil fuels that are not only supercharging the climate crisis but are subjecting TVA customers to electric grid blackouts and energy insecurity. It is long past time for TVA to begin the transition to a renewable and reliable electric grid."

TVA plans to construct a natural gas plant and contract a new pipeline in Cumberland, Tenn., despite a lawsuit from environmental groups. (See *TVA's Cumberland Coal-to-gas Plans Press on over Resistance*.)

The legislators said that according to its last IRP in 2019, TVA will generate 34 million tons of carbon emissions by 2038 and likely will not meet a net-zero emissions goal until sometime after midcentury. They said TVA is forcing its ratepayers, who already have some of the highest energy burdens in the U.S., to shoulder the "costs of its delayed transition to clean, renewable power."

The congressional members also said TVA leaned on MISO's wind output during December 2022's wide-ranging winter storm. They said TVA's aging grid assets are vulnerable to ever-increasing climate risks.

TVA, however, insists it is a "national leader in carbon reduction" and continues to work to decarbonize. In a statement to *RTO Insider*, TVA said that since 2005, it has reduced carbon emissions by 54%, "one of the largest increases in the industry."

Spokesperson Elizabeth Gibson said TVA will adhere to its existing plans to reduce carbon emissions 80% by 2035 "without impacting reliability or affordability."

"We are working towards being carbon neutral by 2050 through an accelerated plan of increasing our solar and energy storage capacity and exploring new technologies, such as small modular reactors [SMRs], that can provide carbon-free power to meet demand at all times," Gibson said. "We will continue working with our federal, state and local partners as we move forward to the clean energy system of the future."

Gibson pointed out that eight of the letter's 10 signatories are from either the Northeast or California, with only Rep. Steve Cohen (D-Tenn.), of Memphis, hailing from TVA's territory. The letter included signatures from Sens. Bernie Sanders (I-Vt.) and Elizabeth Warren (D-Mass.) and Rep. Alexandria Ocasio-Cortez (D-N.Y.). Sen. Jeff Merkley (D-Ore.) also signed.

This year, TVA signed a multinational agreement on SMR development with GE Hitachi Nuclear Energy, Ontario Power Generation and Synthos Green Energy, a Poland-based wind and nuclear generation developer. The quartet will develop and invest in a standard design for GE-Hitachi's BWRX-300 that they hope will be licensed and deployed in the U.S., Canada and Poland, among other countries. (See *TVA Signs Multinational Nuclear Investment Pact on SMR Technology*.)

Gibson also said TVA last year issued one of the nation's largest requests for proposals for clean energy, at 5 GW, and has pledged to bring 10 GW of nameplate solar capacity online by 2035. She also said that over the first nine months of the year, 60% of its generation was from carbon-free sources, including nuclear, hydroelectric and renewables.

But the Southern Alliance for Clean Energy (SACE) said that if TVA continues its current trajectory and includes new fossil fuel-sourced plants in its upcoming IRP, it will struggle to reach net zero by 2050, "let alone 2035."

"As an extension of the federal administration and the nation's largest public power provider, TVA should be leading the way toward our energy future and the Biden administration's carbon-free goals. Instead, TVA is planning to expand fossil fuel infrastructure and make long-term commitments to fossil fuels, which is a direction that's clearly out of alignment with reaching our nation's carbon-free goals," SACE Executive Director Stephen Smith said in a statement supporting the letter.

Smith said TVA's determination to build new gas plants is an indication that the public utility "has run afoul of its mission and the administration's goals and must have oversight from an independent body."

SACE said much is riding on TVA's upcoming IRP because the next plan isn't due until the 2028/29 timeframe, too late for a decarbonization overhaul in the utility's fleet by 2035. ■

Artist's rendering of a possible GE Hitachi small modular reactor in TVA | *GE Hitachi and TVA*

Company Briefs

Omnis Fuel Technologies Restarts West Virginia Coal Plant

Omnis Fuel Technologies last week restarted the coal-fired Pleasants Power Station in West Virginia with the intent to retrofit the facility to use hydrogen.

The plant was first scheduled to be shut down in 2018, however state lawmakers approved a tax break in 2019 that had kept the facility active. Now, Omnis will invest $800 million into the facility to convert the site.

More: *The Associated Press*

Alliant Completes Microgrid Project in Wisconsin

Alliant Energy last week announced the completion of a community-scale microgrid system in Richland County, Wisc.

The microgrid system is one of several advanced research pilot projects Alliant operates as it aims to expand access to storage solutions.

In addition to the microgrid project, the company has announced plans to develop utility-scale battery storage projects alongside its Edgewater Generating Station in Sheboygan and at its Grant County and Wood County solar project sites.

More: *Alliant Energy*

Bila Solar to Create US HQ, Manufacturing Facility in Indianapolis

Singapore-based solar panel maker Bila Solar last week announced it will create a U.S. headquarters and manufacturing facility in downtown Indianapolis.

The company said it plans to spend $35 million to renovate an existing 150,000-square-foot facility.

The facility is slated to open in the summer of 2024.

More: *WISH*

EV-part Maker Daesol Ausys to Build Plant in Georgia

South Korean company Daesol Ausys said it plans to build a $72 million factory in Georgia to make parts for EVs.

The company supplies parts to Hyundai, Kia and General Motors.

Daesol Ausys is scheduled to begin production in December 2024.

More: *The Associated Press*

Ethridge to Replace Manget as CFO at Canoo

Electric vehicle maker Canoo last week announced that Greg Ethridge, a board member, will become the company's new chief financial officer, effectively immediately.

Ethridge replaces Ken Manget, who became CFO in January. It is unclear whether Manget resigned, and a company release didn't cite the reason for his exit.

Shares rose 11 cents (22%) following the news, closing at 64 cents a share on the Nasdaq.

More: *Northwest Arkansas Democrat Gazette*

K&L Gates Adds Boston Partner

Global law firm K&L Gates LLP last week announced it has added Theodore Paradise to its Energy, Infrastructure and Resources practice area.

With more than 20 years of legal experience, including a regulatory background and understanding of renewable project development, Paradise will assist clients in navigating the electric utility industry, particularly in the growing offshore wind area and transmission development.

More: *K&L Gates*

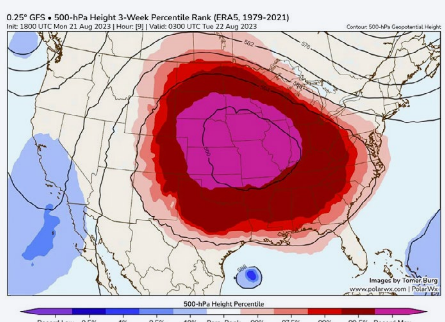
Federal Briefs

Experts: Record Heat Could Plant 'Hurricane Time Bomb' in Gulf

The heat dome responsible for record-breaking temperatures and drought in south Louisiana may have also created a ticking time bomb of "ridiculously warm" waters in the northern Gulf of Mexico, which could rapidly intensify any tropical storm approaching the state's coastline, storm scientists say.

Regional National Weather Service Director Ben Schott said the average sea surface temperatures off the Louisiana coast are between 89 and 92 degrees, which is "way above normal than where they usually would have been 10, 20 or 30 years ago." That heat can fuel any approaching storm, especially if it is not limited by drier air or wind shear, Schott said.

Adding to the warm water threat is the location of the "loop current," an extension of the Gulf Stream, where tropical storms crossing the loop current often go through "rapid intensification." When a system moves over a warm ocean surface, its intensity draws cooler water to the surface. If it's moving slow enough, that can cause the storm to lose strength. The deep, warm water of the loop, however, continues to strengthen storms. Schott said this year's intense heat may have even resulted in deeper warmer water away from the loop current.



More: *Nola.com*

FEMA Announces $3B for Climate Resiliency

The Federal Emergency Management Agency last week announced nearly $3 billion for communities to build resiliency against climate change-fueled extreme weather.

The new money, which will come from Congress' bipartisan infrastructure law passed last year, is being announced just as the agency is running out of disaster-relief funds.

In a first, FEMA awarded resilience funding for extreme heat, agreeing to fund a project proposed by Portland, Ore., to plant 10,500 trees over the next three years to provide more shade, improve air quality and help with flooding during major rainstorms. Other projects include strengthening the grid in Jefferson Parish, La., to withstand 150-mph winds and keep power on during hurricanes; installing new sewer mains in Detroit's flood-prone Jefferson Chalmers neighborhood; and upgrading Nevada's Hobart Creek Reservoir Dam, both to protect water levels and keep the dam safe.

More: *CNN*

Biden Suspends Trump-era Authorization to Ship Gas by Rail

The Department of Transportation last week halted a 2020 Trump policy that allowed natural gas to be shipped by rail until it can publish a companion rule or until June 30, 2025, if a rule is not completed by that date.

The DOT said its action would avoid "potential risks to public health and safety or environmental consequences" and allow for more testing and the inclusion of possible mitigation measures.

More: *The Hill*

State Briefs

CALIFORNIA

PUC Allows More Gas Storage at Aliso Canyon Leak Site

The Public Utilities Commission last week voted unanimously to let Southern California Gas store more fuel at the Aliso Canyon gas storage field, eight years after a leak spewed more than 100,000 metric tons of methane into the atmosphere.

The PUC agreed with a SoCalGas analysis finding that more fuel storage at Aliso could lead to lower gas and electricity costs for residents this winter. However, the decision angered many residents, who see the gas field as a continued threat to their health.

It had been two years since the PUC raised the storage cap at Aliso Canyon, which had been cut after the methane leak, to 41 billion cubic feet. Now the agency has upped the limit to the 68.6 billion cubic feet.

More: *Los Angeles Times*

Vistra Completes Moss Landing Phase III Expansion

VISTRA ENERGY

Vistra recently announced the completion of its Phase III expansion at its Moss Landing Energy Storage Facility.

Vistra's Phase III expansion went into operation June 2 and completed the 350-MW/1,400-MWh portion of its Moss Landing facility, bringing its total capacity to 750 MW/3,000 MWh — the largest of its kind in the world.

More: *Monterey Herald*

GEORGIA

Georgia Power Customers Sould See Bills Rise to Pay for Vogtle

Georgia Power

Geogia Power has filed a rate increase with the Public Service Commission to recover costs associated with the Vogtle nuclear plant.

Georgia Power said customers would pay $7.56 billion more for Plant Vogtle construction costs under an agreement with utility regulatory staff. It would add about $9 to the average residential bill.

The project's overall cost, including financing, is currently $31 billion for Georgia Power and three other owners. Add in $3.7 billion that original contractor Westinghouse paid the Vogtle owners to walk away from construction, and the total nears $35 billion. The reactors are seven years late and $17 billion over budget.

More: *The Associated Press*

ILLINOIS

Will County OKs Solar Farms in Crete Township

The Will County Board recently approved two solar farm projects in Crete Township proposed by Soltage LLC, with the condition that a snake survey be done on one of the projects.

For one of the projects (Crete Goodenow Solar 1), the county will require a solid fence instead of a chain-link fence and a snake survey. If snakes are found on the land, the company has agreed to follow the state Department of Natural Resources and federal guidelines for protecting endangered and threatened species.

More: *Chicago Tribune*

KANSAS

Corporation Commission: Evergy's Rate Proposal Not Justified

evergy

The corporation commission last week said Evergy's proposed rate increase of 9.77% is not justified, and that an increase of 1.66% could be.

Evergy filed for a $204 million increase and said the funds are needed to offset rising interest rates and investments in its power plants, as well as the cost of dismantling retiring plants, IT expenses and several expiring contracts.

The commission is expected to make a final decision at the end of this year.

More: *The Wichita Eagle*

KENTUCKY

PSC Denies Electricity Discounts for Crypto Mining Proposal

The Public Service Commission last week denied millions of dollars in electricity discounts offered by utility Kentucky Power to support a massive cryptocurrency mining operation.

The PSC said the potential risks to ratepayers, particularly in light of Kentucky Power's lack of in-house power generation, outweighed the economic benefits, in regard to Chinese-owned Ebon International's proposed cryptocurrency-mining facility.

The utility said it planned to buy extra power from PJM to serve Ebon International, which would use 250 MW at full capacity and be the largest cryptocurrency mining operation in the state, and other customers. However, the PSC said the costs of buying power elsewhere, or the costs of building in-house power plants to meet Ebon International's needs, come at a risk to more than 150,000 customers.

More: *Kentucky Lantern*

MINNESOTA

PUC Votes to Proceed with Enviro Review of Carbon Pipeline

The Public Utilities Commission last week voted to proceed with an environmental review for part of a proposed Summit Carbon Solutions carbon dioxide pipeline that would carry CO_2 from Midwest ethanol plants to a permanent underground storage site in North Dakota.

The PUC unanimously approved a draft plan laying out the scope of a formal environmental review for one part of the proposed project, a 28-mile segment in Minnesota that would connect an ethanol plant in Fergus Falls to the North Dakota border, where it would connect with Summit's network.

More: *The Associated Press*

NEVADA

PUC Approves NV Energy's Cost Recovery Plan

The Public Utilities Commission last week approved more than $400 million in spending for NV Energy's natural disaster prevention and the continued use of a cost recovery method.

The PUC approved two orders around NV Energy's Natural Disaster Protection Plan (NDPP). One was for about $373 million for programs and projects for 2024-2026, while the other order was to recover $37.2 million for NDPP-related expenses through ratepayers beginning in October.

More: *Las Vegas Review-Journal*

NORTH CAROLINA

Woman's Death Blamed on Substation Attack, Ruled Homicide

An elderly woman's death when her oxygen machine failed during a power outage has been ruled a homicide by the state medical examiner and was blamed on what authorities said was intentional gunfire that hit power substations in her area.

The state's medical examiner determined that Karin Zoanelli, 87, died Dec. 3, 2022, when her oxygen concentrator that helped her breathe lost power. That night, attacks on two power substations left 45,000 without electricity across Moore County. Zoanelli had chronic lung disease with pulmonary hypertension and used an oxygen concentrator at night, which was disabled during the power outage, the medical examiner's report stated.

Officials have not announced an arrest in the case, and a motive remained unclear.

More: *The Washington Post*

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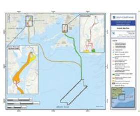

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