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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: The heat dome has settled over the Great Plains. | *Tomer Burg/PolarWx*

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Grid-enhancing Technologies Poised for Growth with Federal Funds

PPL Using, NYSERDA Looking at DLRs; Infrastructure Act Contains $14 Billion for Grid Tech

By James Downing

Grid-enhancing technologies (GETs) already have worked in some areas, and they are set to grow with new federal funding opportunities, experts said on a webinar last week hosted by the Clean Energy States Alliance.

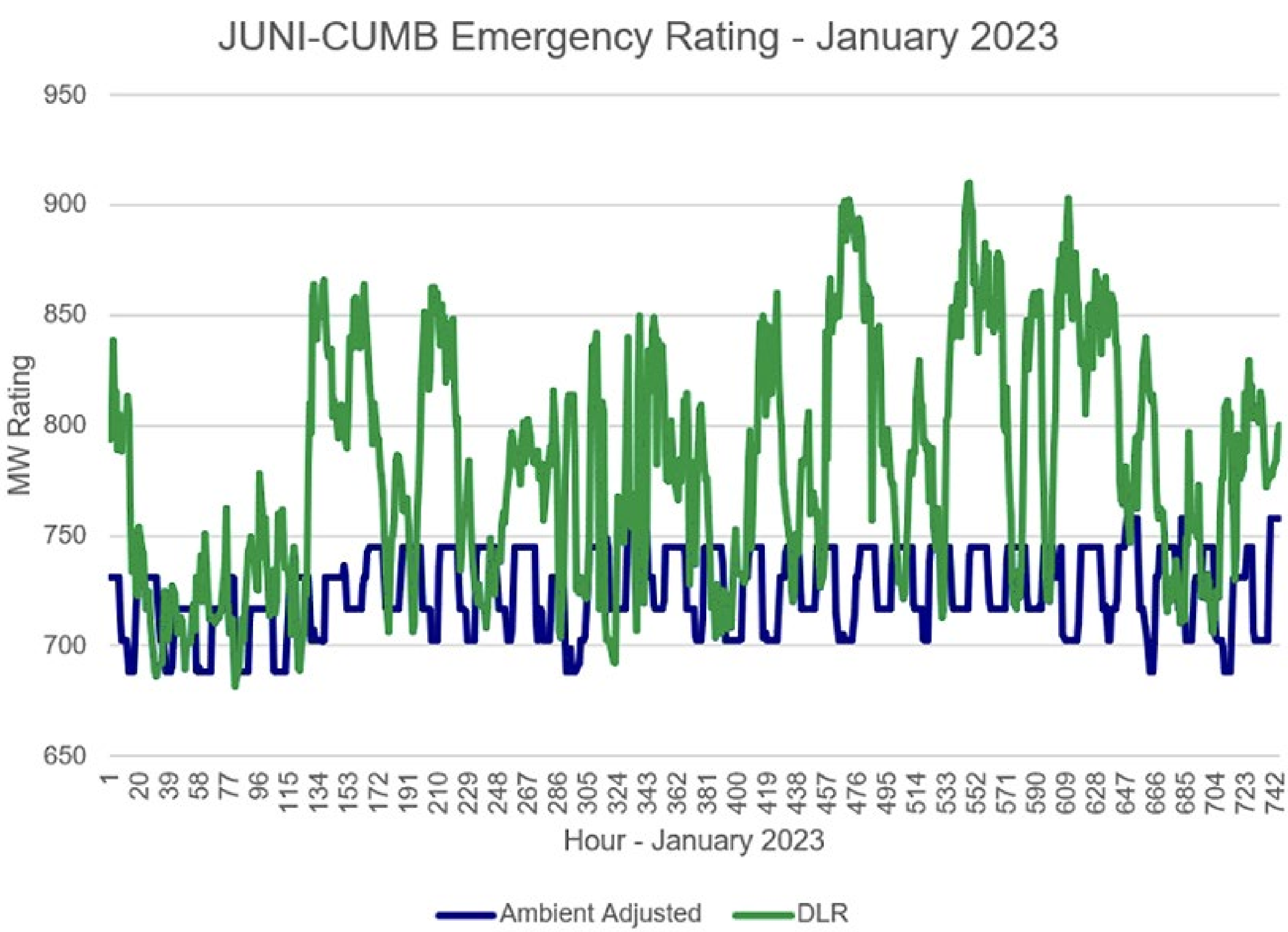
PPL had been looking into using dynamic line ratings (DLRs) since 2020, and it went live with several projects starting last October, including one that has expanded the capacity of its Juniata-Cumberland line in Pennsylvania by 18% under normal conditions and 10% under emergency conditions, said Joseph Lookup, director of asset management.

DLRs consider local conditions such as the ambient air temperature, wind speed, the temperature of the conductor and how much the line is sagging to determine how much power can reliably flow through a transmission line. The sensors used in the technology also can measure the health of the conductor.

Upgrading transmission lines is a costly and complex engineering process, but getting DLRs running was easy, Lookup said. It involved installing sensors on the lines, which takes a couple of days, and building out the information technology system needed to bring the data produced back to PPL and PJM's transmission operators, he said.

"Since we went live in October 2022, we are seeing an average increase ... for the normal and the emergency readings," Lookup said. "And by doing this, it really has hit home with the customers by saving them costs for congestion ... that we were able to avoid by making a bigger pipe for the power to flow through."

PPL's proposal to use DLRs won out in the market efficiency window of PJM's planning process as a cost-effective way of improving the grid. The projects were estimated to save consumers $23 million annually by the RTO,



A slide from PPL showing the benefits of adding dynamic line ratings to one of its transmission lines. | *PPL*

FERC/Federal News

but so far, grid conditions have made it so the savings exceed that estimate, Lookup said.

The New York Energy Research and Development Authority (NYSERDA) has been looking into GETs in recent years to determine how much power it can push through its existing grid, said Senior Project Manager Mike Razanousky.

NYSERDA has been looking into DLRs as well, which can be accomplished using the sensors PPL has installed, but also with more remote approaches, such as using lidar to measure the conditions of a line, and installing weather stations. It also has looked into power flow controls such as phase angle regulators, which can change the flow of power to maximize the use of the existing grid, and storage as a transmission asset.

"When we started this work, we didn't have FERC Order 881, which is now requiring all of us to go to [ambient-adjusted ratings (AARs)] by July of 2025," Razanousky said.

AARs take into account only local air temperatures; Order 881 also opened a docket to study requiring DLRs around the country. (See *FERC Orders End to Static Tx Line Ratings*.) WATT Coalition Executive Director Julia Selker noted that the latter offers more efficient use of existing transmission because wind is a bigger factor in transmission lines' ever-changing capacity than air temperature.

NYSERDA is working with Avangrid on the demonstration of a mobile unit that can measure its transmission system's conditions, and Central Hudson Gas & Electric is installing a permanent system at a substation, Razanousky said.

Another option for helping increase efficiency on the grid is deploying storage as transmission assets; NYSERDA is working on a study that will look into the question, Razanousky added.

The Infrastructure Investment and Jobs Act included up to $14 billion over five years for states and utilities to try out all kinds of GETs, Selker said. The money can help bring the technologies from the pilot level to be used broadly across the entire country.

The grants are available for both states and the industry under various programs, and Selker said the Department of Energy should announce the first ones shortly.

"To put forward a grid-enhancing technologies proposal, you really have to partner with both a technology vendor and a utility to identify needs and impacts and what stage the utilities are at in adopting these technologies," Selker said. "So, I really encourage you to do that groundwork; find out what's feasible."

The more recent Order 2023 on interconnection queues also requires consideration of GETs, she added. (See *FERC Updates Interconnection Process with Order 2023*.) While utilities will look at AARs under Order 881, Selker argued it makes sense for them to start considering the more efficient DLRs at the same time. Under Order 2023, utilities have full discretion on how to evaluate and implement the transmission technologies.

"It really looks like it's down to the state oversight to make sure that the RTOs and the transmission owners are doing that meaningful evaluation of these technologies and fully incorporating them in the processes," Selker said ■ ..

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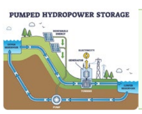

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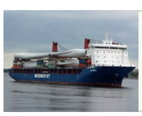

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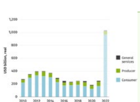

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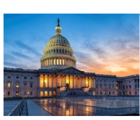
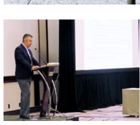


ERO Adds Energy Policy to Risk Priorities List — ERO Insider

NERC Committee Agrees to Shortened Standard Comments — ERO Insider



NERC Confident in Ability to Deliver ITCS On Time — ERO Insider

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FERC/Federal News

ACP Asks FERC for Capacity Accreditation Technical Conference

Request Comes After FERC Rejected ACP Accreditation Concern in February

By James Downing

| Shutterstock

The American Clean Power Association (ACP) *asked* FERC last week to hold a technical conference on capacity accreditation, arguing that the commission's rules need to keep pace with technology and the evolving grid.

The *petition* filed Aug. 22 is not ACP's first attempt to get FERC to address the issue, with the commission in February rejecting a complaint the organization filed against ISO-NE alleging its capacity accreditation rules failed to account for natural gas' performance issues in the winter. (See *FERC Denies RENEW Northeast Complaint*.)

"Grid operators and FERC have been addressing these issues primarily on a regional basis, but the clean energy industry believes it's time for FERC to look at many of these issues more broadly," ACP Vice President of Markets and Transmission Carrie Zalewski said in a statement. "Today's petition provides an opportunity for FERC to hold open discussions that can identify the best possible capacity accreditation methods so that the reliability contributions of all resources — including renewables and storage — can be accurately accounted for."

A central pillar of system planning and electricity market design, capacity accreditation is one of the most critical areas FERC needs to address on a holistic basis, ACP argued. Some regional differences are to be expected, but ACP said the methods should share common goals and general approaches.

Capacity accreditation methods vary widely, and they are often applied inconsistently within and across resource types, making it more difficult to accurately assess national and regional resource adequacy and to make efficient investment decisions, the organization said. With different regions taking on the issue on their own, and FERC's *ex parte* rules, the commission has not been able to take a broader look at the issue, which could help its decisions.

"That constraint will continue to bind policy development going forward, because many regions are actively considering changes to their resource accreditation processes as the resource mix continues to evolve," ACP said.

A technical conference on capacity accreditation would develop a record to foster informed decision-making on the various initiatives likely to arise over the next several years, it said. And a universal framework would not stop the regions from moving ahead on their own.

The industry has different ways of accrediting capacity, including effective load-carrying capability (ELCC), marginal reliability improvement (MRI) and measuring a resource's output during certain peak load intervals.

All of the capacity accreditation techniques include four fundamental design characteristics.

The technique can use a deterministic metric (reflective of only one set of conditions) or probabilistic (a value based on analytical simulations across hundreds or thousands of potential conditions).

Grid operators can also use a prospective/forward-looking assessment, a retrospective assessment based on past performance or a combination that uses a prospective method at first, then adjusts retrospectively based on performance.

The third design characteristic is whether to use an average contribution, in which all resources of the same technology count the same, or a marginal contribution, in which individual resources are measured in comparison to others using the same technology.

The fourth design element is whether fuel assurance is required for individual units or handled probabilistically by unit, unit type or systemwide.

"Because capacity accreditation is increasingly being acknowledged as a critical aspect of our energy system, significant attention is now being focused on this topic in various ISO/RTO stakeholder working groups," the petition said. "However, at present, there is no focused, coordinated discussion occurring at the federal level, either at the commission or at the North American Electric Reliability Corp."

The industry would benefit greatly from a universal discussion around the issue, with a technical conference educating stakeholders, allowing for open discussion with FERC staff and hopefully helping to foster consensus and consistency among regions, ACP said. ■

FERC/Federal News

Duke Files Settlement with Munis at FERC on Battery Dispute

Utility also Launches EV Charging Pilot in North Carolina

By James Downing

Duke Energy Progress (DEP) and the North Carolina Eastern Municipal Power Agency (NCEMPA) filed a settlement with FERC on Thursday that would end a dispute over the latter using batteries to shave its peak demand (*ER22-682*).

Duke serves the power agency under a power purchase agreement in which the utility buys energy, capacity and reserves to meet the municipals' demand. It charged the agency for capacity based on a 12-coincident-peak method.

NCEMPA members started shaving those peaks using behind-the-meter battery storage systems, which led to a dispute at FERC over their impact on Duke's ability to recover its costs.

Duke believed that NCEMPA could figure out when its members' demands were going to hit one of the 12 coincident peaks, thus dispatching batteries to avoid the capacity charges, so it filed changes to its agreement to adjust how the agency was charged for capacity to account for the batteries.

FERC in an order early last year found that Duke had failed to show its proposal was just and reasonable and set the matter for hearing and settlement judge procedures. (See *FERC Orders Negotiations in Duke-Muni Contract Dispute*.)

The filed settlement would resettle transactions between the two starting on Jan. 1, 2023, expressly saying no refunds would be issued for 2022. NCEMPA would be able to keep its batteries and other "energy injection devices," but they cannot exceed 1.75% of its total capacity plus 25 MW. Any batteries or storage devices that NCEMPA uses during peak demand periods can be made subject to that cap.

The two also agreed to a new supplemental capacity charge arrangement for certain interruptible loads whose consumption might not be apparent at the monthly system peak used for calculating capacity charges.

FERC trial staff supported the settlement, saying it would solve the issues in the case in a fair and reasonable way that is consistent with the public interest. The settlement would allow NCEMPA and its members to manage their power use through energy-storage devices while addressing DEP's concerns about their impact on its revenues, they said.

The uncontested settlement would resolve all the issues FERC set for hearing and promote consistency and predictability through 2027 with a new PPA. Duke and NCEMPA asked FERC to approve the settlement without modification or conditions.

EV Charging Pilot

Duke Energy on Monday announced it was launching a pilot program in its North Carolina utilities to offer customers a flat rate for 800 kWh/month of electricity to charge their cars.

The utility is working with Ford, General Motors and BMW to launch its "EV Complete Home Charging Plan." Customers will pay just $19.99/month in Duke Energy Carolinas and $24.99/month in DEP for 800 kWh, which the utility said is about twice as much as the average consumer would use for their cars.

The pilot will use software in the cars themselves to track monthly demand, avoiding the expense of installing a separate meter.

"The average EV owner is already saving about $1,000 per year on fuel costs compared to a traditional vehicle; a predictable monthly subscription charge on top of that is going to ensure predictable savings when charging," Kendal Bowman, president of Duke's utility operations in North Carolina, said in a statement. "Beyond cost savings, EV charging at home tends to be convenient because drivers can leave the house with a fully-charged vehicle and lessen the number of trips to public charging stations." ■

| *Duke Energy*

CAISO/West News

CAISO Files EDAM Proposal with FERC

Proposal Includes Enhancements to Existing Day-ahead Market

By James Downing

CAISO asked FERC last week to approve its tariff revisions implementing an extended day-ahead market (EDAM), as well as revisions to its existing day-ahead market that would also apply to the new regional market (*ER23-2686*).

The EDAM has been in discussion for several years. The proposal would make the ISO's day-ahead market available to participants in the Western Energy Imbalance Market (WEIM).

The proposed revisions, called the Day-Ahead Market Enhancements, are meant to better align day-ahead market outcomes with real-time conditions, which has proven more difficult because of the growth in intermittent resources and more common extreme temperatures as a result of climate change.

"Filing the EDAM tariff with FERC is an important milestone for the CAISO and our partners across the West," CAISO CEO Elliot Mainzer said in a statement Wednesday. "EDAM and the day-ahead market enhancements will build on the success of the Western Energy Imbalance Market and go even further in lowering costs and improving reliability for electricity customers throughout the region. I am grateful for the strong engagement and participation from the diverse group of stakeholders who worked tirelessly to help shape and refine these tariff provisions."

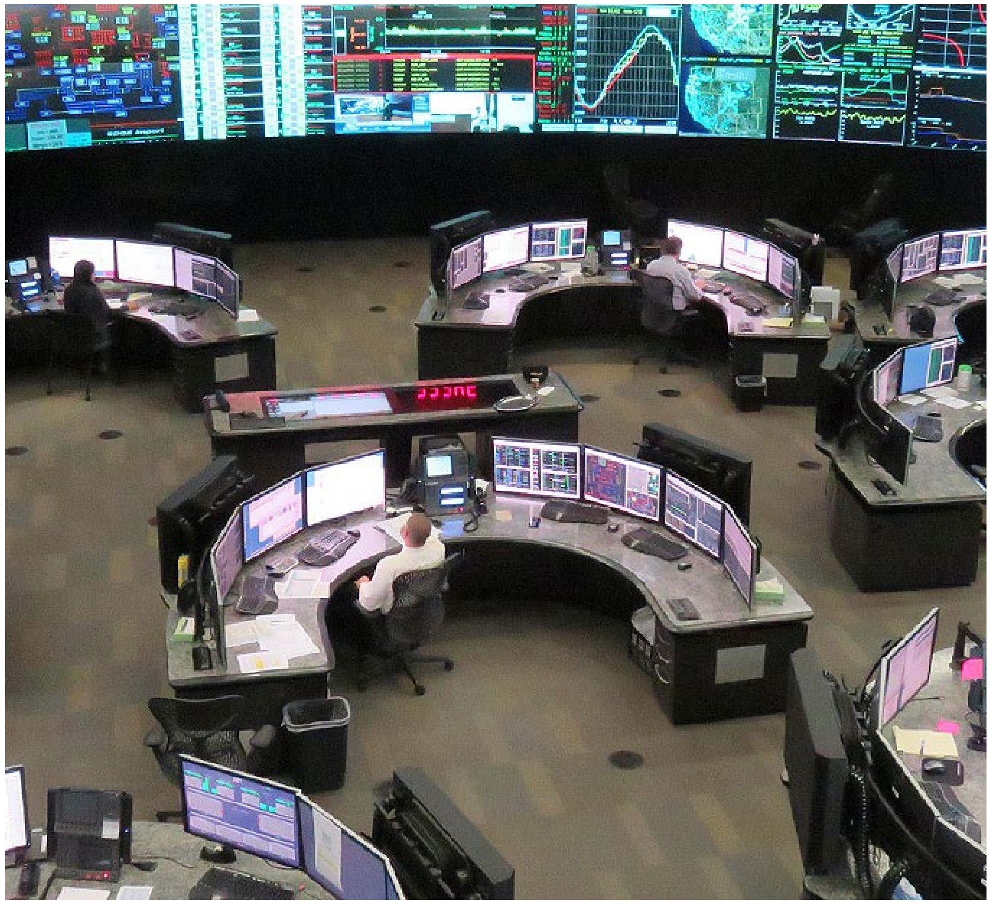
CAISO estimates that the EDAM will save between $100 million and $1 billion annually, which comes on top of benefits already produced by the WEIM. (See *West Could Save $1.2 Billion a Year in CAISO EDAM*.)

The EDAM represents the most significant market enhancement for CAISO and the West since the WEIM was established in 2014, the ISO told FERC. The proposal will enhance reliability, cut costs to ratepayers, optimize generation dispatch across a broader footprint and help participants and states achieve clean energy policies.

Any participants in the WEIM can join the EDAM, with PacifiCorp having said it plans to. (See *PacifiCorp to Join EDAM, Final Plan Released*.)

Market Enhancements

The proposed Enhancements would establish two new products: imbalance reserves and reliability capacity. Both products are aimed at cutting the "load imbalances" between day-ahead market outcomes and the real-time market.



CAISO's control room in Folsom, Calif. | *CAISO*

"Two sets of forecasts drive the net load forecast: the gross forecast of load and the production forecast from wind and solar resources," the filing said. "Unless these forecasts for the day-ahead market perfectly match the forecasts for the real-time market, an imbalance is unavoidable."

Net load imbalances are to be expected, but they have grown in recent years as increasing intermittent resources and extreme weather make grid conditions the next day more difficult to predict.

CAISO currently relies on its out-of-market residual unit commitment (RUC) process to adjust the load forecast and thus avoid being short of the online capacity and ramp capability needed to maintain reliability.

Under the Enhancements, the ISO would procure imbalance reserves up and down to meet the range of expected imbalances between the day-ahead and real-time net load forecasts. It would also procure reliability capacity up in the same way it procures RUC capacity for the same reason currently, and procure reliability capacity down to address scenarios in which the day-ahead market awards too much energy relative to the forecast.

Imbalance reserves would be flexible reserve products to cover uncertainty in the net load forecast and real-time ramping needs not covered by hourly day-ahead market schedules. Any resources-procured imbalance reserves would have to submit economic bids in the real-time market for its awarded capacity range.

Reliability capacity would meet the positive or negative differences between cleared physical supply in the integrated forward market and the load forecast. It is similar to the RUC process, but it could also deal with situations when actual demand exceeds the forecast, while RUC only does the opposite.

CAISO/West News

"With the bidirectional reliability capacity product, the CAISO will replace the existing unidirectional RUC capacity product it procures today with the reliability capacity up product as well as the ability to procure decremental capacity with the reliability capacity down product," the ISO said in its filing.

Suppliers for both products would provide bids for both up and down products. Each bid would have a single price/quantity pair, with imbalance reserves having a $55/MWh cap and reliability capacity bids at $250/MWh.

EDAM Tariff

The EDAM offers a voluntary regional day-ahead market by using the ISO's current day-two market with targeted adjustments that recognize the unique challenges and needs of the WEIM balancing authorities that might participate and other market participants. The new marker would include the Day-Ahead Market Enhancements.

"For the balancing authorities that join, the extended day-ahead market will settle all loads and resources in the day-ahead timeframe and all imbalances between day-ahead positions and the real-time market," CAISO said. "The extended day-ahead market will optimize the transmission and resources offered into the market to identify the most efficient resource commitments and energy transfers to meet forecasted demand across the footprint."

Like WEIM, entities participating in the EDAM would have to show they meet readiness criteria to ensure the ISO and participants are prepared for the operation of the day-ahead market in each balancing area. The proposal also has transitional measures to insulate participants from adverse impacts when the market goes live.

The new market would provide legacy transmission contracts and transmission ownership rights in an EDAM balancing area with a scheduling priority and settlement process consistent with existing mechanisms in the ISO's tariff while making the flow capability available to the entire market.

Another similarity with WEIM is that every balancing authority in the EDAM would have to go through a process ensuring it has enough resources to meet demand, with those that pass being pooled together for the regional real-time market, and those that fail getting a chance to cure that in the integrated forward market.

The EDAM would also take into account the fact that some of the states covered have greenhouse gas regulations, but others do not, by requiring bidders outside of them wishing to sell into such states to include an adder for emissions costs.

The process for joining the EDAM would be based on that for WEIM, with implementation agreements, onboarding cost recovery mechanisms and onboarding processes before participation begins.

CAISO told FERC it could reject the EDAM and still approve the Enhancements, but the latter are needed to approve the EDAM. The new market needs the changes to manage the increasing system variability and uncertainty around the West, but the Enhancements would benefit CAISO's own markets enough to warrant their approval alone, the ISO argued.

The ISO asked FERC for an order by Dec. 21 and asked for an extension of the due date for comments to 30 days after its filing, with replies to be due 20 days after that. ■ ..

CAISO/West News

CAISO Stakeholders Lament Challenges of Gas Procurement

By Elaine Goodman

A working group focused on gas resource participation in CAISO-run markets held its second meeting last week, with stakeholders saying they don't receive enough advance information to make good decisions on gas procurement.

CAISO is hosting the Gas Resource Management (GRM) Working Group to explore challenges that stakeholders face while participating in the Western Energy Imbalance Market and potentially the extended day-ahead market, which is under development.

The working group process will result in an "action plan" that CAISO will use in potentially crafting future initiatives.

During the workshop Aug. 22 and in written comments, stakeholders discussed the challenges of gas procurement.

Salt River Project (SRP) pointed to what it called a "mismatch between when gas is traded, when gas is scheduled and when power awards are made by the organized market."

"It is critical to know the quantity of gas required to meet load/market awards so that the correct amount can be scheduled," SRP said in written comments.

SRP said reliability risks may be created, such as in situations when intraday gas isn't available to buy.

Alan Meck, a business and economics adviser at San Diego Gas & Electric, described the problem as "lack of foresight."

"You have to figure out … am I going to go ahead and buy the gas and then potentially be stuck holding the bag?" Meck said during the meeting. "Or am I going to not [buy the gas] and potentially get an energy schedule going into real time and then have to pay the real-time price?"

Stakeholders including SDG&E and PacifiCorp said their limited ability to store gas adds to the problem. And recent increases in variable energy resource capacity have made forecasts more uncertain when it comes to gas procurement.

Timeline Alignment

The working group is expected to revisit a topic CAISO has explored: a potential alignment of electric and gas market timelines.

CAISO headquarters in Folsom, Calif. | © *RTO Insider LLC*

CAISO said its previous analysis of such an alignment found it wouldn't be in the interest of market participants. In particular, the switch would require business process changes, and earlier timelines might increase forecast inaccuracy.

The ISO has asked working group members to weigh in on whether those issues still are a concern.

On other topics, the Northern California Power Agency proposed a discussion of how hydrogen could be incorporated into the markets.

"Any effort or interest now in incorporating how hydrogen fits into gas resource management will only provide compounding benefits in the future," NCPA said in written comments.

Salt River Project wants to see more discussion of multistage generators, which are units with multiple operating configurations.

"SRP would like to emphasize the importance of multistage generators and that enhancements in their management have the potential to significantly impact efficiency and reliability," SRP said in written comments.

Existing Tools

Vistra noted that CAISO previously discussed gas resource management issues in a 2016 paper called "Commitment Cost and Default Energy Bid Enhancements" (CCDEBE). The CAISO board then approved a CCDEBE proposal in 2018.

"Vistra strongly encourages the CAISO to examine its existing tools and procedures' effectiveness and to implement the remaining elements of CCDEBE as soon as possible," the company said in written comments. "After which, a discussion on whether new tools and procedures are needed can be held."

CAISO's Mark Richardson, who facilitated last week's session, said the ISO will examine what previously was approved — but hasn't been implemented yet — before the next working group meeting.

In addition to last week's session, the *GRM Working Group* met on July 27. After each meeting, CAISO plans to release a discussion paper that summarizes the group's conversation.

The group's next meeting is scheduled for Sept. 18. ■ ..

Conservation Calls Help ERCOT Meet Near-record Demand

By Tom Kleckner

In what is becoming an almost daily occurrence, ERCOT on Sunday issued another appeal for voluntary conservation as the Texas grid operator continues to manage tight conditions during a brutally hot summer.

The ISO called for the market's consumers and businesses to reduce their usage between 4 p.m. and 9 p.m. (CT). As it has since late last week, ERCOT warned of the potential to enter emergency operations because of high demand paired with expected low wind and possibly low solar generation during the evening hours when the sun sets.

The conservation call marked the fourth straight day, and seventh overall, the grid operator has asked for voluntary conservation this summer. Temperatures reached a record 109 degrees Fahrenheit in Houston and broke triple digits throughout much of the rest of Texas.

ERCOT CEO Pablo Vegas | *© RTO Insider LLC*

"What we're seeing are conditions that are more tight than what we have seen on any other day this summer," ERCOT CEO Pablo Vegas told the Public Utility Commission during an open meeting Thursday. "At this time, it's a high likelihood that we expect to be in emergency operations this evening."

That did not happen. The grid operator deployed its newest ancillary service, ERCOT Contingency Reserve Service (ECRS), and non-spin reserve service to close the gap between supply and demand. Pop-up rain showers in the Houston area also lowered temperatures and with it, demand — but not before an hourly average peak of 84.24 GW, more than 1 GW from a record.

ECRS dispatches resources that can respond within 10 minutes of deployment instructions and can operate for at least two straight hours. It also was deployed Friday and Saturday along with non-spin and responsive reserves; energy storage regularly supplied more than 1.2 GW of energy as well.

"Thank you to Texas residents [and] businesses for your conservation efforts, which along with additional reliability tools, helped us to get through a tight peak time," ERCOT tweeted Thursday night, a message it has repeated several times since.

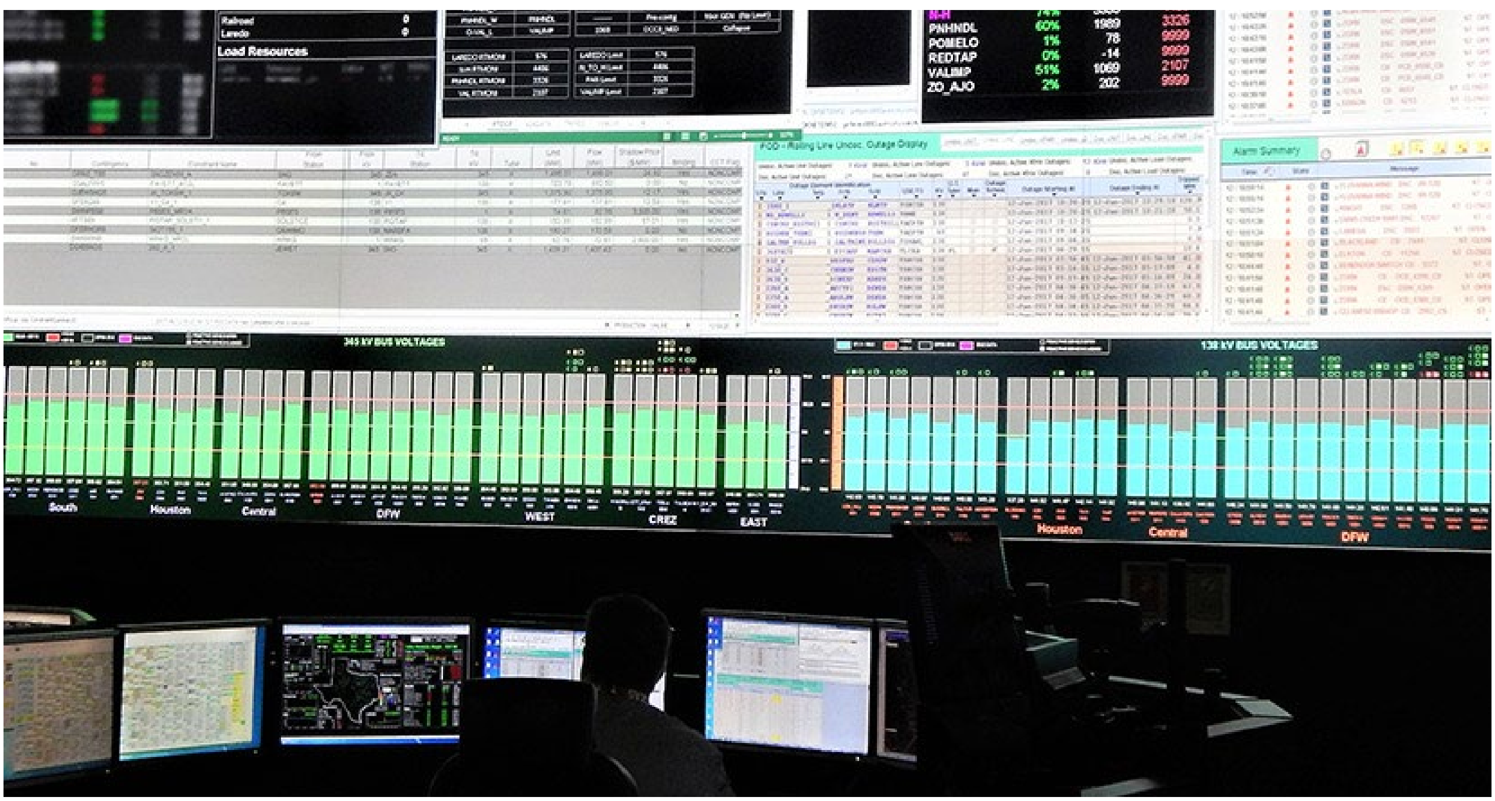
Vegas told the commission the ISO has seen a "very different profile" for wind energy, with an afternoon production of about 6 GW that is several GW lower than normal during summer months. He said the thermal dispatchable fleet has been operating at or near normal forced-outage levels.

"It's really the combination of the very high heat, the very high demand and the low expected output of wind during the solar ramp," Vegas said.

Temperatures are expected to cool slightly in Texas this week. ERCOT's six-day forecast predicts demand to stay below 79 GW for the rest of the week.

The grid operator's record for hourly average demand remains 85.44 GW, set Aug. 10. It has broken last year's high of 80.15 GW 193 times this summer.

ERCOT staff had projected a summer peak of 82.7 GW in its final pre-summer assessment. That mark has been exceeded 98 times this summer. ■



ERCOT's operations center has successfully met demand during a record-breaking summer. | *© RTO Insider LLC*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Staff, Stakeholders Get Serious on RTC, Energy Storage

ERCOT stakeholders last week endorsed the charter and leadership for a task force that will report directly to the Technical Advisory Committee and provide recommendations on real-time co-optimization (RTC) and energy storage resources' (ESRs) state of charge (SOC).

The *Real-time Co-optimization + Batteries Task Force* (RTC+B) will coordinate and review ERCOT and market activities to mitigate risks and support the RTC+B program's implementation. Its responsibilities include managing timelines, providing a forum for analysis or policy decisions and reviewing nodal protocol revision requests (NPRRs).

Battery issues unrelated to RTC are out of scope. However, ERCOT will make time available after the group's meetings should stakeholders want to continue to explore storage.

ERCOT's Matt Mereness, who has volunteered to chair the task force, said he simply forklifted the charter from the previous stakeholder group that produced NPRRs and other rule changes to guide staff's implementation of RTC.

"We said, 'What does it look like to remove implementation risk?' And so structurally, everything is the same," he said during TAC's Aug. 22 meeting.

Mereness also chaired the RTC Task Force that took a first look at the market tool that procures energy and ancillary services every five minutes. Using the approved NPRRs, the new group will develop business requirements for RTC and single-model batteries and review a SOC concept for batteries. (See "RTC Stakeholder Group to Form," *ERCOT Technical Advisory Committee Briefs: July 25, 2023*.)

Key policy issues include parameters for ancillary service proxy offers, triggers for initiating off-cycle security-constrained economic dispatch (SCED) executions, allowing real-time updates to current market offers and in the future with RTC, and evaluating a framework for periodic analysis comparing RTC and the ORDC.

A vendor will start developing the SOC for batteries involved in RTC in January. The task force plans to deliver its completed work in 2026.

Faced with a December target to gain ERCOT Board of Directors approval of its work, the RTC+B group will move quickly. It has already scheduled a Sept. 8 meeting to nominate a vice chair and review the RTC task force's previous work and the sequence of activities necessary for implementation.

"We do think it's important that we get real-time co-optimization done as quickly as possible, given that it's planned to save enormous amounts of money for the market when it's implemented," Mereness said.

The RTC Task Force was disbanded at the end of 2020 following the initiative's completion. The disastrous and deadly February 2021 winter storm and the ensuing drain on staff resources postponed the initiative until recently.


A Broad Reach Power crew works on a storage facility in West Texas. | *Broad Reach Power*

SOC Transparency

In a split vote, TAC approved one of two ERCOT revision requests (*NPRR1186*) designed to improve the grid operator's awareness, accounting and monitoring of an ESR's SOC before the RTC+B project goes live.

As approved by the Protocol Revisions Subcommittee (PRS) earlier in August, the measure adds definitions and telemetry requirements

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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 (DAM) process should begin to respect the AS award limits for ESRs based on duration requirements.

ERCOT has held three workshops on NPRR1186, and it has been the subject of conversation during two PRS meetings. Still, it was discussed for 90 minutes before TAC voted on it.

Storage developers Eolian, Plus Power and Jupiter Power *filed comments* opposing it, saying it would disincentivize longer-duration ESRs that could diversify energy supply and help manage the growing evening ramp's variability because "administratively applied withholding requirements" will limit the resources' ability to provide multihour AS products.

The joint commenters suggested modifying the measure by adding a variable to the calculation of AS, eliminating the ESRs' obligation to stop discharging energy while deployed to provide certain AS, and ensuring compliance obligations address ERCOT's SOC monitoring goals and mitigate unintended consequences.

After TAC endorsed the NPRR in a 22-3 vote with five abstentions — with the consumer and retail electric provider segments providing the pushback — Eolian said it would *appeal the approval* to the ERCOT board when it meets Thursday and request ERCOT be directed to resubmit new NPRRs to separate out system coding issues from the determination of SOC parameters and related compliance obligations.

Eolian said the board should give market participants a chance to work with ERCOT to define "actual reliability issues" and determine how to solve them without creating dangerous unintended consequences.

"Failure to do so will certainly create a chilling effect in the ERCOT market by discouraging the development and construction of longer-duration ESRs in ERCOT, which will be to the detriment of grid resiliency and reliability, as well as all ERCOT consumers," the developer wrote.

Staff pointed out that AS market products work as mechanisms that maintain reliability, not as standalone economic products, and that ESRs create a duration issue. They agreed to review how other grid operators are addressing duration issues.

"There needs to be some perspective on what's on the system now versus what was on the system 10 years ago," said ERCOT's Kenan Ögelman, vice president of commercial operations.

New ORDC Price Floors Set

The committee endorsed another binding document request (*OBDRR048*) that sets two price floors for the operating reserve demand curve (ORDC) in a move to retain and incent new dispatchable thermal generation.

Price adders of $20/MWh and $10/MWh will come into play when operating reserves hit floors of 6,500 MW and 7,000 MW, respectively. ERCOT analysis has indicated the floors would have increased revenues to generators by about $500 million during the 2020 and 2022 pricing years. Thermal generators would have received 80% of those revenues.

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

Stakeholders approved the OBDRR in a 22-7 vote, with one abstention. All six members of the consumer segment voted against the measure over concerns the structure guarantees revenues and prevents customers from responding.

The Texas Industrial Energy Consumers' John Hubbard said the organization still opposes the change and that it has filed a notice of appeal.

The OBDRR was separated from TAC's combination ballot, which passed unanimously. The combo ballot included seven NPRRs, three revisions to the Nodal Operating Guide (NOGRRs), two additions to the Resource Registration Glossary (RRGRRs) and a change to the Planning Guide (PGRR). If approved by the board, these changes would:

- *NPRR1164*: require that resource entities 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 would also 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.
- *NPRR1171*, *NOGRR250*: clarify various reliability requirements for distribution generation resources (DGRs) and distribution energy storage resources (DESRs) seeking qualification to provide AS and/or participate in SCED.
- *NPRR1173*: account for Texas standard electronic transaction processing options for municipally owned utility or electric cooperative service areas in the protocols.
- *NPRR1174*: establish a process allowing QSEs or congestion revenue right (CRR) account holders to return overpayment settlement funds to ERCOT.
- *NPRR1175*: strengthen market entry qualification and continued participation requirements for ERCOT counterparties like QSEs and CRR account holders, classify information in the background check as protected information, modify application forms for QSEs and CRR account holders and add a new background check fee to the grid operator's fee schedule.
- *NPRR1185*: add 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 AS that resources can only provide fast-response service if awarded regulation service in the DAM for that resource.
- *NOGRR215*: allow new remedial action schemes to only address actual or anticipated violations of transmission security criteria when market tools are insufficient and clarify the procedures for retiring schemes.
- *NOGRR249*: specify methods for transmission operators to receive electronic communication of system operating limit exceedances.
- *RMGRR174*: update language to reflect the current practice of posting regional transmission plans and geomagnetic disturbance assessment plans and update data sets.
- *RRGRR033*: add data to the resource registration glossary pursuant to *NPRR1164*.
- *RRGRR035*: add fields consistent with *NPRR1171*. ■

— Tom Kleckner

ERCOT News

Texas Public Utility Commission Briefs

2 VPPs Qualified for Market Participation After Pilot Project's 1st Year

Texas regulators and ERCOT stakeholders last week celebrated a year-long study of aggregated distributed energy resources (DERs) that's resulted in two virtual power plants (VPPs) qualified and able to provide dispatchable power to the state's grid.

Commissioners Jimmy Glotfelty (left) and Will McAdams debate the PUC's administrative processes. | *Admin Monitor*

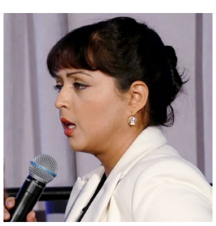
The Aggregate Distributed Energy Resources (ADERs) pilot project tested how consumer-owned, small energy devices, such as energy storage systems, backup generators, controllable electric vehicle chargers and smart thermostats and water heaters, can be aggregated virtually and participate as a resource in the wholesale electricity market (*53911*).

Eight aggregations (ADERS), totaling 7.2 MW, participated in the pilot project. Two ADERs with customers using Tesla Electric Powerwall storage systems have completed required testing and could provide energy and ancillary services through the third quarter. One is linked to Oncor's distribution system in North Texas, the other to CenterPoint Energy's system in Houston.

The other six ADERs are being commissioned.

CenterPoint Executive Vice President Jason Ryan, who chaired the 20-person task force, told the Public Utility Commission during its Thursday open meeting that the pilot project shows Texas is a leader in VPP implementation.

"I'm not talking about just the leader among states in this country, but really in the world. It really changes how customers are using the distribution grid," he said.



Arushi Sharma Frank | *© RTO Insider LLC*

"Every one of those customers, by investing in whole-home backup and then being participatory in the grid, is providing additional reliability services from a private investment and taking off the socialized value of the reliability standard. The growth of this pilot is also an incredibly important data point," Tesla's Arushi Sharma Frank said. "You have to be able to see a resource. It needs to be visible in the system, it needs to be visible to ERCOT, it needs to be visible to the distribution service providers operating the local system and it needs to be understood to be a part of wholesale price formation."

She said the exchange of granular information between the consumers, ERCOT, distribution providers and other market participants has been invaluable.

"All of these things happening in nine months is progress on top of progress on top of progress of the kind that is taking the RTOs years to implement years," Frank said. "Hopefully in the three years that this pilot progresses, the information that Texas will have collected on three disparate systems — retail energy distribution service, and the wholesale grid — will be incredibly valuable to the National Labs. You'll be in the opposite position where instead of the National Labs coming to help you, you will be going to the National Labs and helping them figure out how to monetize DERs and put them into wholesale price formation."

Frank said in a *report* that the project's first phase allowed Tesla to "demonstrably assess" ADERs' viability as providers of energy and reserves. However, Tesla also discovered the costs associated with maintaining a qualified scheduling entity (QSE) and servicing telemetry can be challenging on a small scale. She called for an increase in current QSE caps, noting ADERs' break-even point of 15-20 MW is above that cap.

In a memo, PUC commissioner Will McAdams directed the task force and ERCOT to create a plan for the pilot's second year, following the *project's principles*.

"We would like to understand what performance metrics would need to be met to unlock expansion of grid services or size caps," he said.

ERCOT Evaluating RMR Options

ERCOT CEO Pablo Vegas told the commission it may resort to issuing reliability must-run (RMR) contracts to ensure it has enough capacity to meet demand this winter.

The grid operator issued a *market notice* last week that said while it had determined a gas plant's announced suspension would not create a reliability issue, it was conducting additional analysis to determine whether there's a need for additional capacity from dispatchable resources for the upcoming season.

ERCOT pointed to increasing system demand and a continued reliance on variable output from renewable resources as creating the need for more analysis. It promised a decision by early October as to whether the resource would be able to suspend operations or be extended an RMR contract.

"We are looking at more broadly the needed capacity as we get into this winter season," Vegas told the PUC. "There have been multiple units that have indicated a cease operations and mothballing status or retirement."

ERCOT News

Asked whether staff would evaluate a demand-side solution, Vegas responded affirmatively.

"If we move down this pathway, the requirement would be to evaluate any sort of capacity options, including the load-side," he said. "Effectively, we would be seeking the most cost-effective solution or to close a risk if we identify one on capacity."

Travis Kavulla, NRG Energy's vice president of regulatory affairs and a former Montana state commissioner, tweeted that this would be the first time RMR, normally used for local reliability issues, would be used for system resource adequacy.

"This kind of creates a 'Hotel California' situation," he said, referring to resources' ability to leave. "Only CAISO has used RMR powers for this purpose."

ERCOT said its reliability assessment of the Barney Davis 1 unit near Corpus Christi indicated it is not required to support transmission system reliability. The unit, which has a summer maximum sustainable rating of 292 MW, plans to indefinitely suspend operations on Nov. 24.

Any RMR contracts must be approved by the board.

ISO Prioritizes Market Changes

Vegas also shared development timelines for *ERCOT work initiatives* as a result of recently passed legislation that he called The Big Five: a reliability standard, a dispatchable reliability reserve service (DRRS), the performance credit mechanism (PCM), a multi-step floor to the operating reserve demand curve (ORDC) and real-time co-optimization (RTC).

"Those five initiatives together make up a suite of changes that are going to help to drive reliability and make changes to the market constructs that are designed to improve both operational flexibility as well as long-term resource adequacy," Vegas said.

ERCOT will work with consultants to update a previous value-of-lost-load study and to perform a review of its cost of new entry metric, currently valued at $105,000/MW-year after a 2012 analysis. Commission staff plan to file a proposed rulemaking on a reliability standard based on the ISO's study; the PUC will take up the proposal in January.

ERCOT has considered a reliability standard since a 2011 winter event and has long operated with a 13.75% target reserve margin based on a 0.1 loss-of-load expectation and a traditional dispatchable generation fleet.

The PUC opened a docket (*54584*) earlier this year to evaluate and establish an appropriate reliability standard.

The grid operator's staff has proposed a three-part framework that considers the duration and magnitude of a loss-of-load event besides the occurrence's frequency. It's intended to better quantify risks associated with an LOLE when intermittent resources comprise a large percentage of the generation fleet.

The commission already has approved the ORDC's changes but it still must endorse a document that formalizes the two price floors. Staff will make the software changes in November and must file reports on performance metrics and DRRS' effects in 2024 and 2025, respectively. (See *Texas PUC Approves ERCOT's ORDC Modifications*.)

ERCOT staff and stakeholders will resume their work on RTC and energy storage resources' state of charge, work delayed by the disastrous 2021 winter storm. The Real-time Co-optimization + Batteries Task Force will meet Sept. 8 with a 2026 deployment target. (See "Staff, Stakeholders Get Serious on RTC, Energy Storage," *ERCOT Technical Advisory Committee Briefs: Aug. 22, 2023.)*

ERCOT also is developing a "framing document" outlining PCM decision points for the PUC. Vegas said staff will take the commission's feedback and prepare a strawman proposal for a series of workshops with stakeholders and PUC work sessions. ERCOT and the market monitor will perform a cost-benefit analysis before the Texas Legislature next meets in 2025, after which protocols will be drafted.

Vegas said he expects it will take another two years to implement the PCM. The market construct would retroactively reward dispatchable generation that meet performance criteria during the tightest grid periods with incentive payments.

Asked whether RTC, a market tool that procures energy and ancillary services every five minutes, will still be needed when the PCM is deployed, Vegas said efficiency, reliability and market transparency are key factors.

"We should always be looking at the combination of tools we have to incentivize the goals of the ERCOT grid," he said.

The DRRS is a non-spin ancillary service that supports system reliability and mitigates the use of reliability unit commitment. It is open to resources capable of running for at least four hours at their high sustained limit; being online and dispatchable no more than two hours after being called on; and with the dispatchable flexibility to address inter-hour operational challenges.

ERCOT plans to move nodal protocol revision requests through the stakeholder process this fall to codify the DRRS' sub-type. Upon approval early next year, staff will make system changes and begin offering the service by Dec. 1, 2024.

PUC Rules Against SWEPCO

The commission gave Southwestern Electric Power Co. (SWEPCO) until Sept. 8 to explain why and how the recovery of carrying costs alone is tied to and adequately accounts for the PUC's determination on the prudence of a recently retired coal plant (*53931*).

The order is related to SWEPCO's application to reconcile fuel costs. An administrative law judge in July *found* the retirement decision to be prudent after the utility reached a partial settlement agreement resolving all other issues.

SWEPCO's parent company, American Electric Power (NASDAQ:AEP), announced the 580-MW Pirkey plant's retirement in 2020. The unit, which sits in SPP's Texas footprint, stopped operating in March. In May, the Texas commission rejected the utility's application to build 237 MW of accredited renewable capacity at the Pirkey site. (See *Texas PUC Rejects SWEPCO Application for Renewables at Pirkey*.)

The PUC plans to take up the matter during its Sept. 28 open meeting.

The commission also denied SWEPCO's rehearing request of its May denial of renewable resources at Pirkey, saying that their acquisition is not in the public interest (*53625*).

In other proceedings, the PUC:

- Gave El Paso Electric Co. until Sept. 23 to advise the commission what it intends to do with its application for proposed electric vehicle-ready pilot programs and tariffs following a recent law that addresses the operation of public EV charging stations and goes into effect on Sept. 1 (*54614*).
- Overturned an ALJ's decision approving Wind Energy Transmission Texas' interim wholesale transmission rates following appeals by Texas Industrial Energy Consumers and Steering Committee of Cities Served by Oncor (*55029*). ■

— Tom Kleckner

MISO News

MISO Calls 1st Summertime Emergency amid Systemwide Heat Wave

122 GW of Demand Nears 127 Record; TVA Struggled too

By Amanda Durish Cook

CARMEL, Ind. — MISO instated maximum generation procedures Thursday to manage a pervasive heat wave blanketing its footprint.

The grid operator *called* a maximum generation event to begin at noon ET as temperatures climbed to 95 degrees Fahrenheit and above throughout most of its system. It *de-escalated* the emergency into a maximum generation warning effective at 7:30.

MISO topped 122 GW of demand during the evening peak, short of its all-time peak demand record of 127 GW, set July 20, 2011. By 5 p.m., hub LMPs were around $220/MWh in MISO Midwest and $150/MWh in MISO South.

Ahead of the demand surge, MISO forecast a 127-GW peak by 5 p.m. with a little more than 121 GW in cleared offers.

MISO previously enacted a footprint-wide capacity advisory and conservative operations Aug. 21, before a maximum generation alert for Thursday. As it geared up for the day, the RTO asked all members to update their market data with their best available information.

MISO said it was contending with forced generation outages paired with abnormally high temperatures and higher load than forecast a day prior.

DTE Energy's 1.1-GW Fermi 2 nuclear plant south of Detroit was *offline* during the week's hottest weather. The company was forced to perform an unscheduled outage because of a coolant leak.

"We'll see how this week shapes up. We've already sent out several hot weather alerts and capacity advisories," MISO Director of Market Administration John Harmon said ahead of the emergency declaration and the most intense heat at the Reliability Subcommittee's meeting Aug. 22.

The Tennessee Valley Authority also struggled alongside MISO in the heat. On Thursday, the U.S. Energy Information Administration *reported* that TVA's 27 GW in net generation was no match for 32 GW in forecasted demand. The federal utility had been relying on gigawatts of imports from MISO and its other neighbors since Aug. 20.

August had already been peppered with tricky operating conditions and alerts related to summer heat stressing MISO's grid.

The RTO also declared conservative operations instructions to members in Wisconsin and parts of its northern footprint Aug. 3. At the time, MISO said it was experiencing tight capacity, a loss of generating units and low wind production.

MISO issued another round of conservative operations for MISO South on Aug. 11 and again on Aug. 14. In that timeframe, South was also subjected to multiple hot weather alerts and capacity advisories.

Before this week, MISO had not encountered a summertime energy emergency; it avoided ordering up load-modifying resources during another heat wave in late July. (See *MISO Preps for Heat Wave, Anticipates Annual Demand Peak*.) The blistering temperatures wrought a 121-GW peak July 27, which until now stood as MISO's annual peak. Otherwise, systemwide load averaged 86 GW in July.

MISO achieved a little more than 3-GW all-time solar peak July 25. At the Reliability Subcommittee meeting, Harmon said the RTO expects to keep eclipsing solar output records as utilities bring more facilities online. ■

Fermi 2 nuclear plant | *DTE Energy*

MISO News

MISO South Support for Sloped Demand Curve Wanes on Opt-out Provision

Stakeholders Disapprove of Separate Demand Curves for Subregions

By Amanda Durish Cook

CARMEL, Ind. — State regulators of MISO South are withholding support for MISO's plan to implement a sloped demand curve in its capacity auctions based on a proposed option for states to shield themselves from the effects.

The majority of Organization of MISO States members sent a *letter* last week to MISO CEO John Bear, urging MISO to move away from a vertical demand curve and file for FERC approval on a sloped demand curve in the fall so it can be implemented in the 2025/26 planning year. OMS said a sloped demand curve is essential to the footprint's future reliability.

"MISO's current resource adequacy construct does not provide the true value of capacity and does not address the resource adequacy challenges facing the MISO region. As a result, it does not send the price signals that motivate the decisions necessary to maintain MISO's systemwide reliability going forward," OMS said.

MISO shares the goal to make a fall filing and use a sloped curve in the 2025/26 Planning Resource Auction. (See *MISO: Sloped Demand Curve Would Have Raised 2023/24 Capacity Prices*.)

During an August OMS board meeting, North Dakota Commissioner Julie Fedorchak said the sloped demand curve is "one of the most important, immediate" things MISO could do to support reliability and send a signal to dispatchable generation that their output is valuable.

However, OMS' letter is not unanimous: MISO South states did not sign on, since OMS backed MISO's opt-out provision contained in the demand curve proposal. The opt-out is meant to respect state jurisdiction over resource adequacy.

MISO's opt-out provision is shaping up to require load-serving entities to opt out of the sloped demand curve for three years at a time, provided they can prove they have anywhere from 1.5 to 3% over their planning reserve margin requirement. Failure to meet the obligation could result in penalties that are 2.7 times the cost of new entry for generation.

Entergy has said MISO's design is too harsh and instead has advocated that for LSEs to opt out, they must prove they can meet 50% of their planning reserve margin requirement for three consecutive years.

MISO staffers have said the Entergy proposal resembles the RTO's failed attempt to institute a 50% minimum capacity obligation. (See *FERC Again Rejects MISO Minimum Capacity Obligation*.)

Entergy put its proposal forward for a stakeholder vote this month; the measure passed 25-20 in an email vote.

Speaking at an Aug. 22-23 Resource Adequacy Subcommittee meeting, Bill Booth, consultant to the Mississippi Public Service Commission, said a full third of MISO members opposed the letter of support, not exactly an "overwhelmingly majority" of MISO states supporting MISO's proposal.

Mike Robinson, MISO | *© RTO Insider LLC*

MISO's Mike Robinson said the opt-out was borne out of the understanding that most of MISO's load-serving entities already engage in some sort of integrated resource planning.

"And we respect that," Robinson added.

Robinson said MISO isn't on the hunt for a convex shape to the demand curve; rather, its loss of load expectation studies are informing the shape.

"If we're going to do this auction, let's do it right, and make sure the supply and demand reflect market fundamentals, and stand up a more efficient market," Robinson said.

Stakeholders Question Separate Curves for Midwest, South

Meanwhile, some stakeholders remain dissatisfied with MISO plans to develop separate demand curves for its Midwest and South subregions.

MISO plans to churn out separate, seasonal demand curves for MISO Midwest and MISO South to account for seasonal margin requirements and the possibility of the transfer constraint binding. MISO said it will develop curves independent of one another based on its systemwide loss of load expectation study.

But stakeholders said they struggled with the rationale to create separate curves. Customized Energy Solutions' David Sapper asked why MISO would continue to calculate a footprint-wide planning reserve margin requirement but maintain subregional demand curves.

Robinson said MISO is starting from established practices that it's comfortable with.

"We made a conscious decision not to change the loss of load analysis," MISO's Neil Shah said. MISO's loss of load analysis doesn't currently contemplate MISO's subregional transfer limit.

WEC Energy Group's Chris Plante said applying separate curves for the Midwest and South creates a "slippery slope" because market participants place different values on excess capacity.

"Where does it end?" Plante asked. "We could create separate curves for each local resource zone. … There's a limit to where we can keep tacking things onto our [resource] adequacy construct."

"This was a compromise," Executive Director of Market and Grid Strategy Zak Joundi said, adding that MISO began with the assumption that it would have a single curve. However, he said that's not how the system operates and how recent Planning Resource Auction clearing prices have shaken out. MISO has experienced price separation between the Midwest and South multiple times after capacity auctions.

MISO Independent Market Monitor David Patton said he was confused as to why MISO is treating the Midwest and the South as if they're "islands" with the curves when that's not how the system operates. MISO had said it's unlikely but possible under the new curves for price separation between the regions to occur even without a binding subregional transfer limit, prompting Patton's remarks.

WPPI's Steve Leovy said MISO is pursuing a "very aggressive timeline" that could result in some "half-baked" concepts finding their way into the filing.

As part of the move to a sloped curve, MISO will remove its annual price cap. In the future, the total annual price for a local resource zone could reach as high as four times the cost of new entry (CONE) if shortages occur in all four seasons. MISO's current auction design employs a 1.75 times CONE price cap for a local resource zone.

MISO's new curve design will preserve states' right to set their own planning reserve margin for their jurisdictional utilities. To date, no state has ever elected to supersede MISO's reserve requirements. ■

MISO News

FERC OKs $21M Settlement in Arkansas Steel Mill's DR Scheme in MISO

By Amanda Durish Cook

FERC last week approved a settlement over an Arkansas steel mill's yearslong failure to reduce load as a registered demand response resource in MISO.

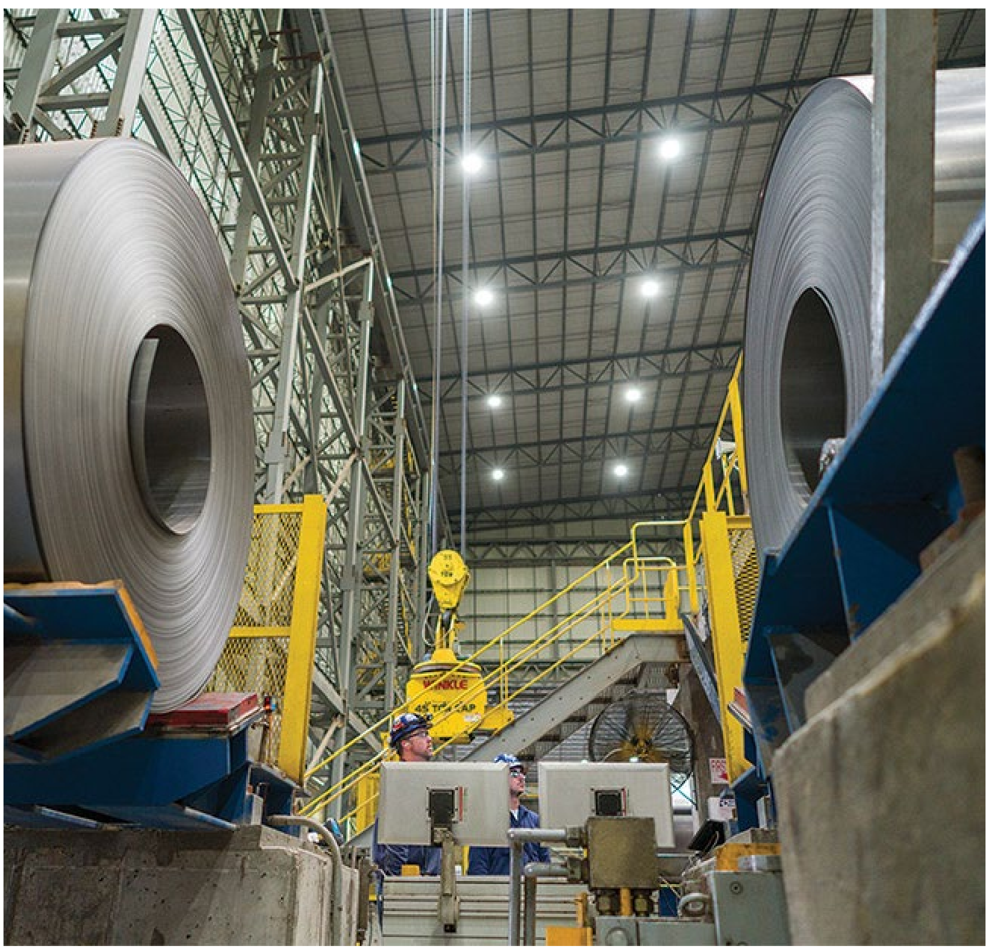
The commission on Aug. 21 sanctioned a $21 million reimbursement as part of an agreement involving Big River Steel in Osceola, Entergy Arkansas and the commission's Office of Enforcement (*IN23-11*).

Big River will return nearly $16 million in profits it received from September 2016 through April 2022 for its participation in MISO's demand response program. The company also will pay a $6 million civil penalty to the U.S. Treasury and pledge to provide compliance training to its traders if it ever intends to participate again as a demand response resource in MISO.

Entergy Arkansas, which served as the market participant for Big River, will return $5 million it received and credited to retail customers. Entergy also will coordinate with the Arkansas Public Service Commission to return to its ratepayers the approximate net $8 million they were charged for the demand response activity associated with Big River. Under its agreement with Big River, Entergy Arkansas collected a 10% administrative fee, as well as charges for the avoided energy consumption.

For years, Big River submitted offers in MISO's day-ahead and real-time markets through Entergy Arkansas. Big River's operations can require up to 300 MW at a time. However, FERC's Office of Enforcement said that except for a seven-day period during the winter storm that lasted Feb. 16-22, 2021, the steel mill "did not change mill operations to alter energy consumption levels when MISO accepted its demand response offers."

Enforcement staff concluded that Big River "operated its mill at the same load levels as it would have if it had not been" a demand response unit within MISO. They said MISO made demand response payments to Big River when its load was below its usual baseline, but those below-average usages still were in the normal course of mill operations.



| Big River Steel

From late 2016 to April 2022, MISO paid nearly $21 million for Big River's participation as a demand response resource. The RTO charged Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy Texas and other MISO South load-serving entities for the load reductions.

FERC said while Big River ultimately decided how much and when to offer reduced energy usage into MISO's day-ahead and real-time markets, Entergy Arkansas also is culpable for the steel mill's conduct. Under the settlement agreement, the two "neither admit nor deny the alleged violations," according to FERC.

FERC said from 2016 to mid-2020, Big River submitted offers to MISO for load reductions that would correspond to expected outages. By the latter half of 2020, Big River usually offered 100 MW in reductions in the MISO market, even if it had no reason to expect an outage the next day.

Starting in 2019, FERC said Big River additionally would make small, 1-MW offers daily in MISO's day-ahead market. FERC said by submitting the small offers, it received demand response payments daily, thereby allowing it to undermine MISO's baseline use calculation that it performs for its demand response resources.

MISO and Big River staff reportedly clashed in 2019, when the steel mill requested a demand response payment for a previously planned outage. MISO refused and told Big River to pursue a settlement dispute.

FERC said Big River and Entergy Arkansas have committed to working with MISO to ensure that the amounts they're surrendering will "be returned to the market participants that were charged those amounts."

In an emailed statement to *RTO Insider*, Entergy Arkansas said it agreed with FERC's findings that Big River operated its mill at load levels as if it weren't a demand response unit and didn't alter energy consumption when MISO accepted its demand response offers.

However, spokesperson Neal Kirby said Entergy Arkansas "is not aware of any evidence suggesting that Big River tried to game MISO's demand response program." ■

MISO News

MISO Strengthens Resolve on Marginal Capacity Accreditation; Stakeholders Displeased

Stakeholders Concerned FERC Will Reject Because of Unfairness

By Amanda Durish Cook

| Invenergy

CARMEL, Ind. — Stakeholders remain frustrated with MISO's plan to enact a marginal capacity accreditation as staff insist the approach will measure the true value of capacity.

MISO is dedicated to a new accreditation plan directly based on a combination of individual past performance and a class average performance during risky hours for different types of generation. The grid operator hopes to file the plan with FERC in November. (See *MISO Intent on Marginal Accreditation and Requirements Based on Risky Hours*.)

At an Aug. 23 Resource Adequacy Subcommittee meeting, MISO adviser Davey Lopez said the RTO is working to pin down more risky hours to base capacity credits on. MISO may consider adding more hours throughout the year when margins dipped to around 3% or lower, he said.

The accreditation will apply to most MISO classes of resources, including gas, coal, hydro, nuclear, storage, wind and solar. MISO's load-modifying resources still need an accreditation plan. MISO said it also intends eventually to determine LMRs' accreditation based on their availability during the times of highest need on the system. It said it will make a separate LMR filing next year.

Most resource accreditations will take a hit using the direct loss of load approach versus MISO's existing accreditation calculation based on unforced capacity and availability during risky hours.

Under MISO's new accreditation method, the class average for gas-fired resources will range from 89% to 70% based on the time of year, coal will be anywhere from 91% to 72%, hydro will receive 99% to 69%, nuclear 91% to 80%, pumped storage 98% to 57%, solar 37% to 1%, wind 18% to 12%, energy storage 95% to 94% and run-of-river resources 100%.

Lopez said MISO will prepare other loss of load modeling sensitivities that consider higher solar penetration on the system.

But Minnesota Power's Tom Butz called for more "fully developed" future fleet mix assumptions in MISO's loss of load modeling before MISO pursues the new accreditation.

"To say you're not going to do that before the filing, I don't feel that's responsible," he said. "That's a shortfall of the modeling."

Lopez said MISO plans include more factors in its future loss of load modeling. But he said MISO will not use its second planning future — the same one MISO's long-range transmission planning currently relies on — in loss of load modeling.

"To match Future 2, that would take a significant amount of time and resources, and we have already begun analysis," he said.

Other stakeholders asked for MISO to hold off on making a FERC filing until it can conduct more comprehensive modeling that includes future system changes.

Executive Director of Market and Grid Strategy Zak Joundi committed to sharing future projections of accreditations with stakeholders before filing for FERC approval.

Lopez said MISO already has conducted extensive modeling analysis, involving hundreds of millions of rows of data. He promised to share more findings in October.

Constellation Energy's John Orr said MISO's analysis seemed too "assumption-driven," and asked for more details behind MISO's performance assumptions by resource class.

"We're struggling with, 'how can this be real?' We're trying to understand these dramatic changes," Orr said.

Orr said it doesn't seem fair that other generators' outage scheduling practices will affect the accreditation of other, similar resources.

Other stakeholders warned that MISO won't be able to satisfactorily defend its proposal in front of FERC because resources won't be given a fair crack at accreditation.

MidAmerican Energy's Dehn Stevens said the direct loss of load approach is "extraordinarily complex" and makes it impossible for load-serving entities to anticipate capacity credits and plan resource additions.

"We're really struggling with how we're going to translate this," Stevens said.

WEC Energy Group's Chris Plante suggested MISO split its resource classes by age of plants so newer units aren't grouped with outage-prone, older units.

"Maybe we shouldn't be lumping those all in the same class," he said.

Lopez said accreditation boils down to a simple reflection of contribution during loss of load hours in modeling. He said an accreditation based on loss of load is in the same currency as

MISO News

MISO's reserve margin requirements. He said the new accreditation will resolve an existing "disconnect" in MISO's resource adequacy construct.

"If resources perform better during those risky hours, they're going to get a bigger slice of the credit," Lopez said.

Xcel Energy's Kari Hassler said stakeholders need to better understand how MISO arrived at its class average percentages.

"MISO is asking us to dive in, but that's difficult when we don't understand," Hassler said. She also said MISO should refrain from making changes to its loss of load modeling during its proposed three-year transition to the new accreditation. Others agreed MISO already should have a new loss of load modeling that's more reflective of actual operations in place before it switches to the new accreditation style.

Lopez said MISO plans a September workshop to explain its loss of load modeling under the new accreditation.

Wisconsin Public Service Commissioner Tyler Huebner said he was frustrated that MISO's modeling is so poorly understood among stakeholders that NextEra Energy and Invenergy enlisted Astrapé consulting to try to make sense of it.

With the help of Astrapé, NextEra and Invenergy concluded MISO should expand the window of risky hours it will use in the accreditation beyond the loss of load hours MISO's annual study produces. They said, "expanding the definition of loss of load to include more critical reliability hours per season provides a more consistent signal to resources."

Chris Miller, FERC liaison to MISO, said FERC already is examining publicly available information on MISO's possible new accreditation method, even though it hasn't been filed.

MISO to Change LSEs' Reserve Responsibility in Accreditation Filing

MISO's new accreditation proposal now contains changes to how it allocates what share of the planning reserve margin requirements load-serving entities will be responsible for. The amendment represented a change from last month's version of the proposal.

MISO said it now will dole out a share of the PRMR to LSEs based on their local resource zones' load during loss of load events. The move is another step away from MISO's once-pervasive use of unforced capacity values.

MISO said it needs the change because loss of load risk occurs in extreme conditions, or during 90/10 load probability events; however, it said LSEs' obligations are based on the expected 50/50 load probability.

Lopez said MISO's proposal "seeks to allocate the planning reserve margin requirement to load-serving entities more commensurate to their contribution to reliability risk."

The announcement seemed to be an unwelcome addition and visibly took stakeholders by surprise, though staff said they'd been signaling since last month they would adjust LSEs' reserve obligations with the new accreditation style.

"It's really scary not to have a feel for what we're going to be responsible for," Orr said. He argued that although MISO plans to fully implement the accreditation by 2028, that's "already here" for some market participants. Orr pointed out that states like Michigan require resource planning four years in advance.

MISO will spend more time discussing accreditation at the next Resource Adequacy Subcommittee meeting Oct. 3-4. ■

MISO News

MISO Revisiting Tx Reconfiguration Studies Due to Low Approval Rates

Rising Congestion Costs Draw Attention to Reconfigurations

By Amanda Durish Cook

CARMEL, Ind. — MISO is open to making edits to its process for approving transmission reconfiguration plans that reduce congestion costs to increase the programs' odds of approval.

MISO has approved two congestion cost reconfigurations of 44 submittals to date, resulting in a 4.5% approval rate. The grid operator *said* it's evaluating its market study process for reconfigurations "due to time commitment and low approval rates."

Multiple stakeholders said MISO's low approval rate of reconfiguration proposals is disappointing. They said when load-serving entities submit a reconfiguration plan, it already has a healthy amount of study behind it.

At the Aug. 22 Reliability Subcommittee, Alliant Energy's Mitch Myhre asked for MISO to conduct a nonpublic sit down with stakeholders to get a better understanding of study input and "why results are coming out the way they are."

MISO said it may introduce some edits to its transmission reconfiguration study and approval process at a future Reliability Subcommittee.

MISO members have been paying more attention to transmission reconfigurations with congestion costs on the rise. Last year, MISO assembled a nonpublic Reconfiguration for Congestion Cost Task Team, which focuses on transmission owners' plans to reroute transmission flows during times of heavy congestion costs. The task team maintains a monthly list of the top congested constraints within the footprint that might benefit from a reconfiguration.

Some MISO members have said it's imperative MISO use reconfiguration plans because major transmission expansion that will ease congestion still is years away from being built. ■

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MISO News

MISO Expects Sedate Fall, Emerges Unscathed from Heat Emergency

NOAA Expects Warmer-than-normal Fall; Demand Should be Short of Record

By Amanda Durish Cook

MISO said it likely can take on fall with sufficient capacity and minimal operating challenges.

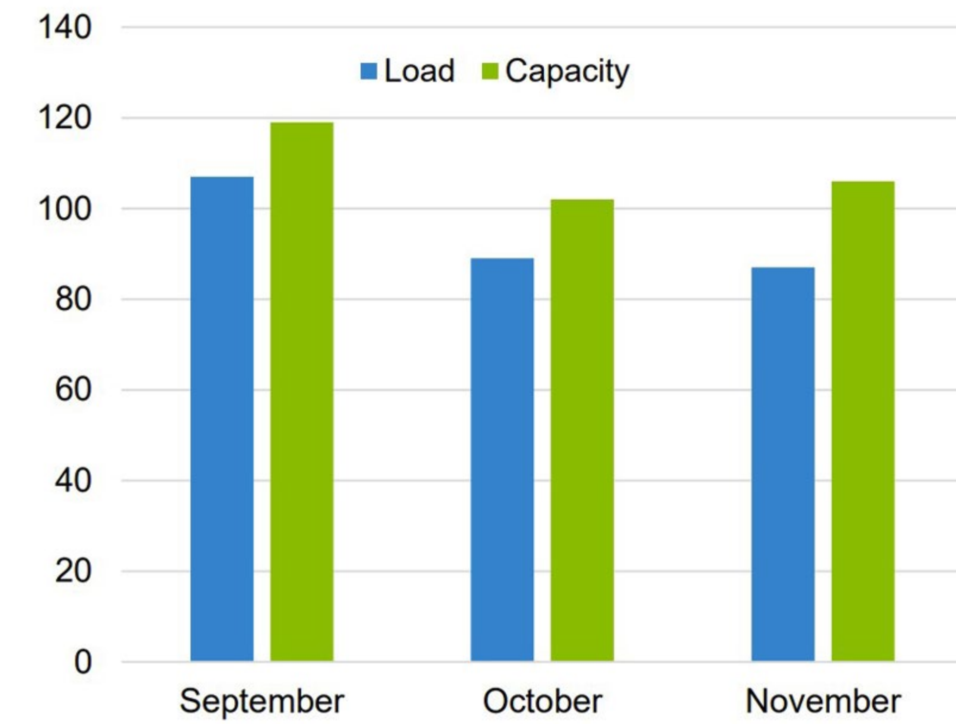
The grid operator issued a fall *outlook* last week, where it said it should have enough capacity to last the season. It anticipates having 119 GW in firm capacity to handle an expected 107-GW peak in September, 102 GW in October to cover an 89-GW peak and 106 GW in November for an 87-GW peak.

MISO said it should be able to operate squarely within its nonemergency resources through November. However, it said on the slim chance it experiences a confluence of load that could rise as high as 117 GW with unusually high generation outages, it could require all of its 10 GW in load-modifying resources on a September day. That's the most serious possible scenario MISO foresees. The RTO first must issue a maximum generation emergency to access any of its load-modifying resources.

MISO's record fall demand stands at 115 GW on Sept. 22, 2017.

On average, MISO experiences nearly 33 GW in generation outages over the fall; outages have hit almost 45 GW at certain times during past seasons.

The National Oceanic and Atmospheric Administration is anticipating a warmer-than-normal autumn for MISO South and average precipitation across the MISO footprint.



MISO expected load versus capacity in fall| *MISO*

MISO may have the worst of summer high temps behind it after it declared a maximum generation emergency to manage heat-driven load and forced generation outages Aug. 24. The grid operator ordered load-modifying resources for more than seven hours and escaped the heat wave without taking the most serious step of load shed. (See related story, *MISO Calls 1st Summertime Emergency amid Systemwide Heat Wave*.) By Thursday night, it had *terminated* its maximum generation warning, capacity advisory, conservative operations instructions and hot weather alert for the entire footprint. However, it issued a fresh alert early Friday for lingering heat in MISO South. ■

NYISO News

NYISO Previews New York City Tx Needs Assessment

ISO Mulling Order 2023 Rehearing Request

By John Norris

RENSSELAER, N.Y. — NYISO last week *updated* the Transmission Planning Advisory Subcommittee (TPAS) and Electric System Planning Working Group (ESPWG) about the New York City Public Policy Transmission Need assessment.

Ross Altman, transmission integration manager at NYISO, outlined the baseline case assumptions and methodology for the forthcoming viability and sufficiency assessment, which evaluates whether a proposed transmission solution would fulfill the deliverability requirements set forth by the state's Public Service Commission.

The PSC called for solicitations from energy developers that could deliver at least 4,770 MW of offshore wind energy from Long Island's coast to New York City and fulfill the state's goals of producing 9,000 MW of OSW by 2035. (See "NYC PPTN," *NYISO Addresses NYC Near-Term Reliability Need*.)

Developers will work with Consolidated Edison, the company responsible for Long Island's transmission system, to design a solution that not only delivers energy to the city, but also upgrades the local buildout to be more resilient to higher voltage outputs.

Several attendees were apprehensive about the timing of the required technical conference on the PPTN and whether there would be enough time to have it by the end of the year, as the meeting will be the first chance to learn more about the PPTN and ask both NYISO and Con Ed questions before solicitations are issued. The conference is slated for the fourth quarter.

Altman told questioners to expect the meeting to happen before December, but that the ISO will provide details on the conference as soon as possible. The conference "is very much top of mind, and our intent is to get this kicked off soon," he said.

Kevin Lang, partner at Couch White, asked how energy storage will be considered.

Altman responded, "We will certainly have certain amounts of storage modeled, especially projects that have gone through Class Year 2021; however, [the ISO] will be modeling them at zero output, so not injecting or absorbing."

Lang also asked for clarification on the baseline case assumptions related to downstate renewable output and what the presumed energy production conditions will be in a proposal's evaluation.

Altman said the assumptions are set around 10 to 15% for solar output and OSW at full output: "Imagine it will be a very windy, slightly sunny condition."

The ISO asks any questions to be sent to *publicpolicyplanningmailbox@nyiso.com*.

Long Island PPTN

NYISO also *kicked off* its lessons-learned process for the Long Island PPTN solicitation, which selected Propel NY Energy to facilitate the delivery of offshore wind energy throughout the state. (See *NYISO Selects Propel Project for Long Island Transmission*.)

Altman said the ISO is willing to consider all improvements to the process and wants stakeholders to provide feedback that could improve the current New York City PPTN and future solicitations.

Michael Mager, a partner at Couch White, said many developers were struck by the huge discrepancies that occurred between developers' bids and the estimated cost by the ISO's consultant —sometimes trillions of dollars.

Altman acknowledged the potential differences but expressed confidence in NYISO's estimates. He said any further questions, concerns or suggestions should be sent to *PublicPolicyPlanningMailbox@nyiso.com*.

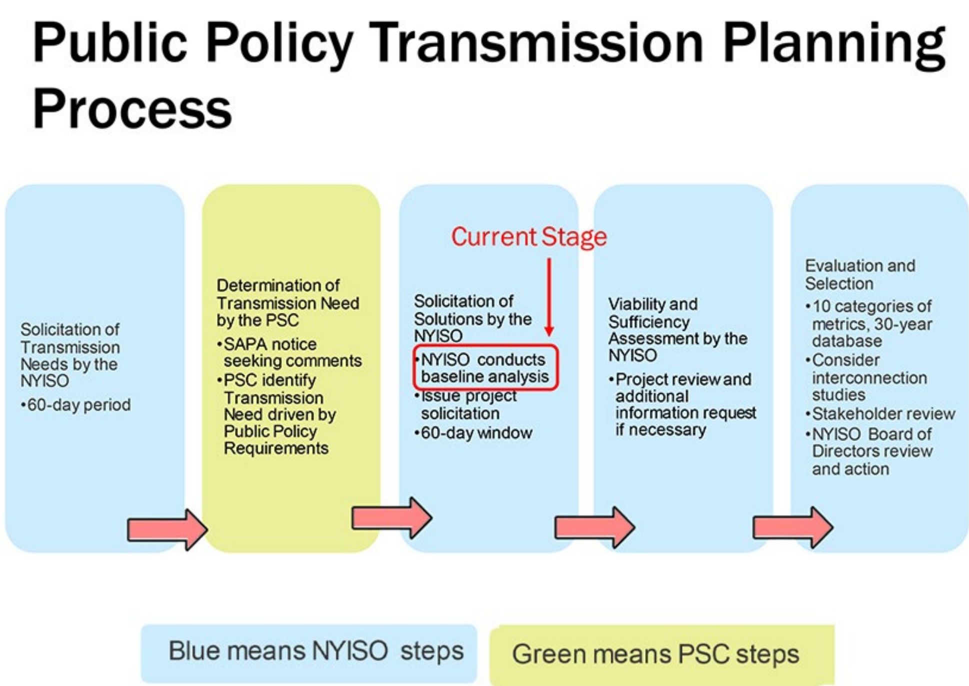
System & Resource Outlook

NYISO staff *presented* the preliminary outline for the second System & Resource Outlook report.

The biannual Outlook forecasts New York's transmission system for the next 20 years and came in response to the state's Climate Leadership and Community Protection Act, which mandated aggressive goals climate and energy goals that forced the ISO to adjust its system forecasting processes. (See "NYISO Releases the Outlook," *NYISO OC Discusses NOPR Comments, High Temps, EDS Results*.)

The report will be benchmarked to 2021 and modeled on an hourly load profile. It will include new emission-allowance considerations and programs, such as the Ontario Carbon Price scheme or the Regional Greenhouse Gas Initiative.

Chris Wentlent, chair of the New York State



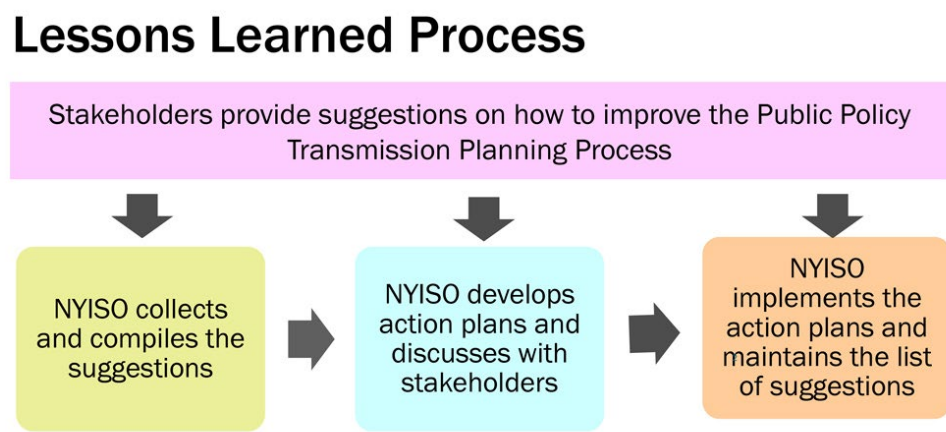
Overview of New York's Public Policy Transmission Needs procedure | *NYISO*

NYISO News

Reliability Council's Executive Committee, and Howard Fromer, who represents Bayonne Energy Center, asked whether NYISO considered the state's cap-and-invest policy, which would establish dynamic limits on emissions-producing activities and is working its way through state agencies. (See *NYISO to Comment on State's Cap-and-invest Plan*.)

NYISO responded that it could be considered as part of the Outlook's base assumptions should it become pertinent.

Additional feedback or questions must be sent to *Jfrasier@nyiso.com* at least one week prior to the ESPWG's meeting Sept. 21.



Overview of NYISO's PPTN lessons learned process | *NYISO*

FERC Order 2023

The TPAS/ESPWG also received an update on the status of FERC Order 2023 compliance from NYISO, which said it is focused on the potential requests for rehearing or clarification on the order.

FERC's July order sought to unclog interconnection queues by imposing financial penalties. (See *NYISO 'Still Digesting' FERC Order 2023*.)

NYISO attorney Sara Keegan told members the deadline for requests is Monday but that the ISO has not made a final determination on whether to submit a request. It will work to develop a compliance strategy after all rehearing and clarification motions are addressed.

Mark Reeder, representing the Alliance for Clean Energy New York, asked how the commission's order would fit into NYISO's ongoing work on its interconnection queue.

Keegan responded that "the order was pretty generous about independent entity variations" and seems flexible enough to work NYISO's own proposals into the compliance directives, but this avenue is still under consideration.

Keegan added that compliance filings are due within 90 days of the rule's publication in the *Federal Register*, but she does not expect that date to be earlier than late November; also, extension requests could be filed, which would further delay the process. ■

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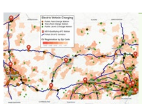
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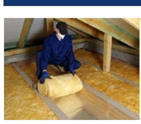
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NYISO News

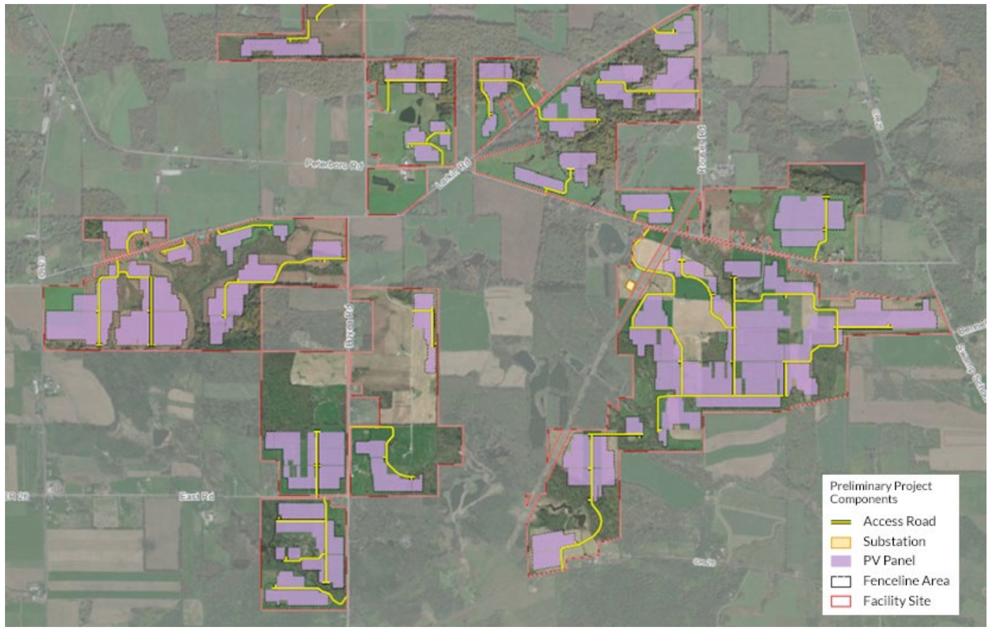
NYISO Cautions FERC on Solar Dev's Request for More Time in Queue

Oxbow Hill Solar Cites "Circumstances Beyond Its Control" in Not Meeting Milestone

By John Norris

NYISO last week raised a caution flag on a solar developer's request for FERC to waive certain interconnection queue procedures, which the ISO said could have marketwide implications (*ER23-2559*).

Oxbow Hill Solar — a 140-MW utility-scale solar *project* to be built in Madison County, in rural Central New York, by Cypress Creek Renewables — completed NYISO's interconnection studies for large facilities and joined Class Year 2021 after accepting its cost allocation. It was expected to be operational by the end of 2026, but because of "circumstances beyond its control," the developer failed to meet a subsequent regulatory milestone to finalize its siting and interconnection agreements, so it requested an extension to Aug. 11, 2024.



Preliminary layout of Oxbow Hill Solar facility in Fenner, N.Y. | *Cypress Creek Renewables*

In comments filed with the commission Thursday, NYISO did not take a position on the request, but, citing Order 2023 and FERC's prior emphasis to adhere to deadlines, the ISO highlighted the importance of milestones in the interconnection process and expressed concern that granting the waiver without limits could negatively impact other projects in the queue.

Both FERC and NYISO have sought to unclog its interconnection queue, with Order 2023 setting penalties on projects that fail to progress through the queue and the ISO streamlining portions of its study processes. (See "FERC Order 2023," *NYISO Previews New York City PPTN*.)

The ISO acknowledged that granting Oxbow's one-time request might not pose an immediate threat but argued that prolonged delays could increase the potential for adverse impacts. It did support Oxbow's request for FERC to act by Oct. 30, and it said if the commission approves the waiver, its requested deadline was acceptable.

Oxbow said it was on track to submit its siting and interconnection permits on time, but a directive from the New York State Energy Research and Development Authority, which tightened energy deliverability requirements for obtaining renewable energy credits, halted its progress.

A solution to NYSERDA's concerns was identified, but Oxbow worried the delays would force it "all the way back to the first step of the NYISO's extensive interconnection process," where it would be placed into a new class year and be operational significantly later.

Oxbow said the waiver will not harm other market participants, is limited in scope to mitigate potential negative impacts and will remedy a "concrete issue" while helping New York achieve its climate and energy goals. ■

PJM News

PJM Stakeholders Vote Against All CIFP Proposals

By Devin Leith-Yessian


David "Scarp" Scarpignato, Calpine | © RTO Insider LLC

VALLEY FORGE, Pa. — None of the 20 proposals PJM and stakeholders drafted through the Critical Issue Fast Path (CIFP) to rework the capacity market garnered sector-weighted support from the Members Committee on Wednesday.

The vote caps off five months of stakeholder meetings, culminating in the proposals being presented to the PJM Board of Managers on Wednesday before the MC vote. With the stakeholders' portion of the CIFP process complete, the board now will decide if it will direct PJM to make a FERC filing to revise the capacity market and what form that may take. In its *letter* initiating the process, the board targeted Oct. 1 for making a filing.

Board Chair Mark Takahashi said they will work through the proposals and perspectives they heard Wednesday and how stakeholders voted when considering next steps over the coming weeks. He said the board may reach out to CIFP package sponsors for more information about what they proposed.

"I do think we're trying to get something as far as we can in the next few weeks," he said.

Though none of the packages received the committee's support, PJM CEO Manu Asthana said he saw pockets of support that could aid the board in its deliberations. PJM posted the sector-weighted voting results on its *website*. The detailed voting report likely will come later in the week.

"We're going to have to spend several working sessions working item by item ... and this input is going to be invaluable," he said.

A proposal focused on limiting the October filing to revising the Capacity Performance (CP) nonperformance penalty rate generators pay should their units not meet their obligations during an emergency, as well as the stop-loss limit capping the amount they can pay in penalties over a year. Instead of being based on the net cost of new entry, the proposal would have based the penalties on the Base Residual Auction (BRA) clearing price for that delivery year. The Independent Market Monitor; Daymark Energy Advisors and East Kentucky Power Cooperative; and American Municipal Power (AMP) and J-Power all submitted identical proposals making those changes, which were voted on as one. (See "Several Stakeholders Propose Variants of PJM Proposals," *PJM Stakeholders Finalize CIFP Proposals Ahead of Vote*.)

Speaking after the vote, Paul Sotkiewicz, representing J-Power USA, urged the board to take into consideration that changing the CP structure to de-risk the market using the BRA price as the basis for penalties and stop-loss did receive majority support (2.8 out of 5), although it failed to meet the sector-weighted threshold. It was the only proposal to receive a majority of support. He noted that the MC previously endorsed changing the penalty rate and stop-loss to be based on the auction clearing price in May. (See *FERC Approves PJM Change to Emergency Triggers*.)

"I would encourage you to think clearly that you're getting a second signal from the membership on that," he said.

PJM's annual capacity market proposal was the second-highest vote getter with 41% support. It includes the risk modeling, winterization requirements, hourly bilateral capacity obligation exchanges and other components of the seasonal proposal the RTO has made throughout the CIFP process, but retains the annual capacity auction structure. The seasonal model received 24.7% support. (See "PJM Adds Annual Auction Design Proposal," *PJM Stakeholders Finalize CIFP Proposals Ahead of Vote*.)

Two proposals from AMP and J-Power received the third- and fourth-highest support, 39.4% and 37.9%. They would create a transitional phase with the changes to the penalties, as well as revising the balancing ratio to include net exports and applying the same penalties to FRR resources that generators participating in PJM's Reliability Pricing Model face. The option of using physical penalty commitments also would be eliminated for FRR entities. (See "Stakeholder Hourly Capacity Proposals," *PJM Stakeholders Finalize CIFP Proposals Ahead of Vote*.)

The proposal for the second phase would revise use of a variant of the Monitor's proposed hourly capacity model, changed to have a two-year procurement horizon with two Incremental Auctions and no exceptions to the requirement that capacity resources offer into the energy market.

The Monitor's Sustainable Capacity Market followed in fourth place with 37.4% sector-weighted support and would have paid capacity for each hour they are able to offer their capacity into the energy markets. (See "Monitor Proposes Hourly Model with Annual Pricing," *PJM Stakeholders Finalize CIFP Proposals Ahead of Vote*.) ■

PJM MRC Briefs

Stakeholders Defer Vote on Generation Deactivation Issue Charge

VALLEY FORGE, Pa. — PJM's Markets and Reliability Committee voted to defer a decision on an *issue charge* that would create a new senior task force to investigate changes to the generation deactivation process.

PJM and the RTO's Independent Market Monitor are jointly sponsoring the *problem statement* and issue charge. (See "PJM and Monitor Present Generation Deactivation Issue Charge," *PJM MRC/MC Briefs: July 26, 2023*.)

Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

The scope includes discussion of the triggers for when PJM can offer a reliability-must-run (RMR) contract to a generator seeking retirement, the compensation for RMR resources and the timing of when a resource owner must notify the RTO of its intent to retire a unit.

Following feedback from the initial first read in July, the issue charge was revised to break out the discussion of resource compensation into its own phase to be considered prior to the other elements.


Paul McGlynn, PJM | © *RTO Insider LLC*

Presenting the proposal, PJM's Paul McGlynn said the current compensation structure lacks clarity, as resources that opt not to use the formula rate for determining RMR compensation instead make FERC filings that can offer differing interpretations on cost recovery.

McGlynn envisions an additional RMR contract trigger for a resource that would create a shortfall in black start capability in a region if it were to retire.

PJM is seeking to lengthen the 90-day notice generators are required to provide before a desired deactivation date because the timeline leaves little time for planners to make necessary upgrades to ensure that the grid can remain reliable without the resource. Advanced knowledge of deactivations will be increasingly important given the scale of retirements PJM expects to see over the next decade, McGlynn said.

Stakeholders discussed PJM's change to the issue charge, stating that expanding use of RMR contracts to maintain resource adequacy would be out of scope for the task force. Cost allocation for RMR contracts under the existing transmission violation trigger and changes to the capacity market also are listed as out of scope.

GT Power Group's Tom Hyzinski said considering whether RA should be a rationale for offering an RMR contract could offer an additional tool if a large number of generators simultaneously decide to deactivate.

"We don't want to approve an issue charge that prevents things from being discussed that need to be discussed," Hyzinski said.

McGlynn said the RTO is already looking into improving the capacity market's ability to ensure resource adequacy.

PJM Senior Vice President of Market Services Stu Bresler said there are backstop provisions in the tariff that allow additional capacity to be procured outside of the Base Residual Auction (BRA) cycle if the RTO falls below its targets.

Whether the process should preclude interactions with the capacity market was discussed at length both during the July meeting and on Thursday, with several stakeholders concerned the task force and its solutions could be fragmented from market changes being considered in other forums.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said several areas of the issue charge were ambiguous and could lead to procedural arguments distracting from core issues. He and other stakeholders suggested amendments to clarify that language in the issue charge, which were adopted by PJM and the Monitor.

Vistra's Erik Heinle said the revisions had improved the issue charge from its first read but that he believes the first phase should be RMR compensation and timing.

Monitor Joe Bowring said he would support breaking the issue charge into two separate stakeholder processes, with his focus being primarily on compensation.

Peak Market Activity Credit Changes Endorsed

Stakeholders endorsed tariff revisions to address the amount of credit market participants must maintain to satisfy their peak market activity (PMA) requirement, which is their highest exposure in the past year. (See "First Read on Peak Market Activity Credit Activity Proposal Expected in August," *PJM MRC/MC Briefs: July 26, 2023*.)

The changes include redefining the PMA surplus and shortfall parameters, introducing minimum exposure and minimum transfer

PJM News

amounts to the tariff language and increasing the PMA reset from occurring semiannually to weekly. The reset reconciles over- and under-collateralization that occurs as energy prices and demand fluctuate.

The revisions also increase the number of permissible early payments from 10 to 13 to provide more flexibility, and the rolling invoice period was increased from three weeks to four.

PJM's Yong Hu said staff had backcast numerous solutions and believe the proposal is optimal.

Denise Foster Cronin, of the East Kentucky Power Cooperative (EKPC), said the utility had concerns with PJM's initial proposal but that stakeholders and PJM were able to produce a strong compromise.

Bresler said because the proposal was endorsed by the Risk Management Committee (RMC) on Aug. 22 without objection, it would normally have been a consent agenda item for the MRC; however, staff are aiming to implement the tariff revisions before winter.

PJM Provides First Read on Reserve Certainty Issue Charge

PJM gave a first read of an issue charge and problem statement that seeks to address several areas of the reserve market, largely to address a decline in the response rate since the two tiers of reserves were consolidated in a market overhaul implemented Oct. 1. (See "PJM Seeks Stakeholder Process on Reserve Certainty," *PJM MRC/MC Briefs: July 26, 2023*.)

Since presenting the issue charge to the MRC in July, PJM has revised the timeline laying out the order in which it seeks to address each of the work areas and added more education on the topics. The bulk of the immediate needs would be initiated upon approval of the issue charge, with an expected duration of six to nine months, followed by discussion on the longer-term items expected to take 12 to 18 months. Also, several changes were made to the work areas.

The immediate needs are reserve performance and penalties, aligning the offer structure with fuel procurement, deployment, and ensuring that procurement reflects system need. Longer-term needs include the eligibility requirements for reserve resources and incentivizing flexibility to meet system needs.

Bowring said he think the out-of-scope portion of the issue charge — which would allow PJM to prevent discussion of changes that could impact the RTO's "ability to maintain reliability and compliance with NERC standards" — should be more specific and could be used by PJM to curtail discussion.

Bowring said PJM has previously made such assertions in response to participants, including the IMM, who disagreed with PJM's approach.

"No one will propose changes that they believe will reduce reliability or compliance with NERC standards. The issue is how best to maintain reliability and compliance. There are multiple paths to those objectives. The ability to discuss options should not be arbitrarily limited," he said.

The declining reserve response rate led PJM to increase its reserve requirement by 30% in May, overriding stakeholder objections. The Monitor at the time objected that the change was not needed and not supported by the data. PJM's Donnie Bielak said the issue charge is intended to produce a permanent solution that is more satisfactory for stakeholders. (See "Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides," *PJM MRC/MC Briefs: May 31, 2023*.) ■

— Devin Leith-Yessian

SPP Sets New Summer Peak as Great Plains Roast

By Tom Kleckner

SPP set a new record for summer peak demand Aug. 21 as a heat dome settled over the Great Plains.

The grid operator, which serves a 14-state footprint in the middle of the country, registered a peak demand of 56.18 GW at 4:27 p.m. CT. That broke the previous mark of 53.24 GW set last summer by nearly 6%.

The record came as SPP was operating under a conservative operations advisory, declared because of the extreme heat, high load forecast and low wind forecast. The RTO issued another conservative operations advisory Aug. 22. It also remained under previously declared resource and weather advisories that were extended until 8 p.m. Friday.

None of the advisories require public conservation and have been issued to raise awareness of potential reliability threats.

Demand within the footprint hit 54.63 GW on Aug. 22, according to *GridStatus*.

About 143 million people in the country's heartland were under heat alerts last week. The National Weather Service is expecting high-temperature records to fall as the oppressive heat continues into this week.

Sitting almost squarely under the heat dome, parts of Kansas were under an excessive heat warning through Friday. Lawrence saw a heat index of 134 degrees Fahrenheit on Aug. 20 and Topeka broke an unofficial record at 127. Other cities in the region have seen, and will continue to see, heat indices approaching 120 F.

SPP spokesperson Meghan Sever said SPP expected to have enough generating capacity to meet the demand and its assessments don't raise reliability concerns. The RTO's summer reliability assessment indicated a 99.5% probability the system will have sufficient capacity to meet demand.

C.J. Brown, SPP's director of system operations, said during a recent stakeholder meeting that the alerts and advisories are becoming regular.

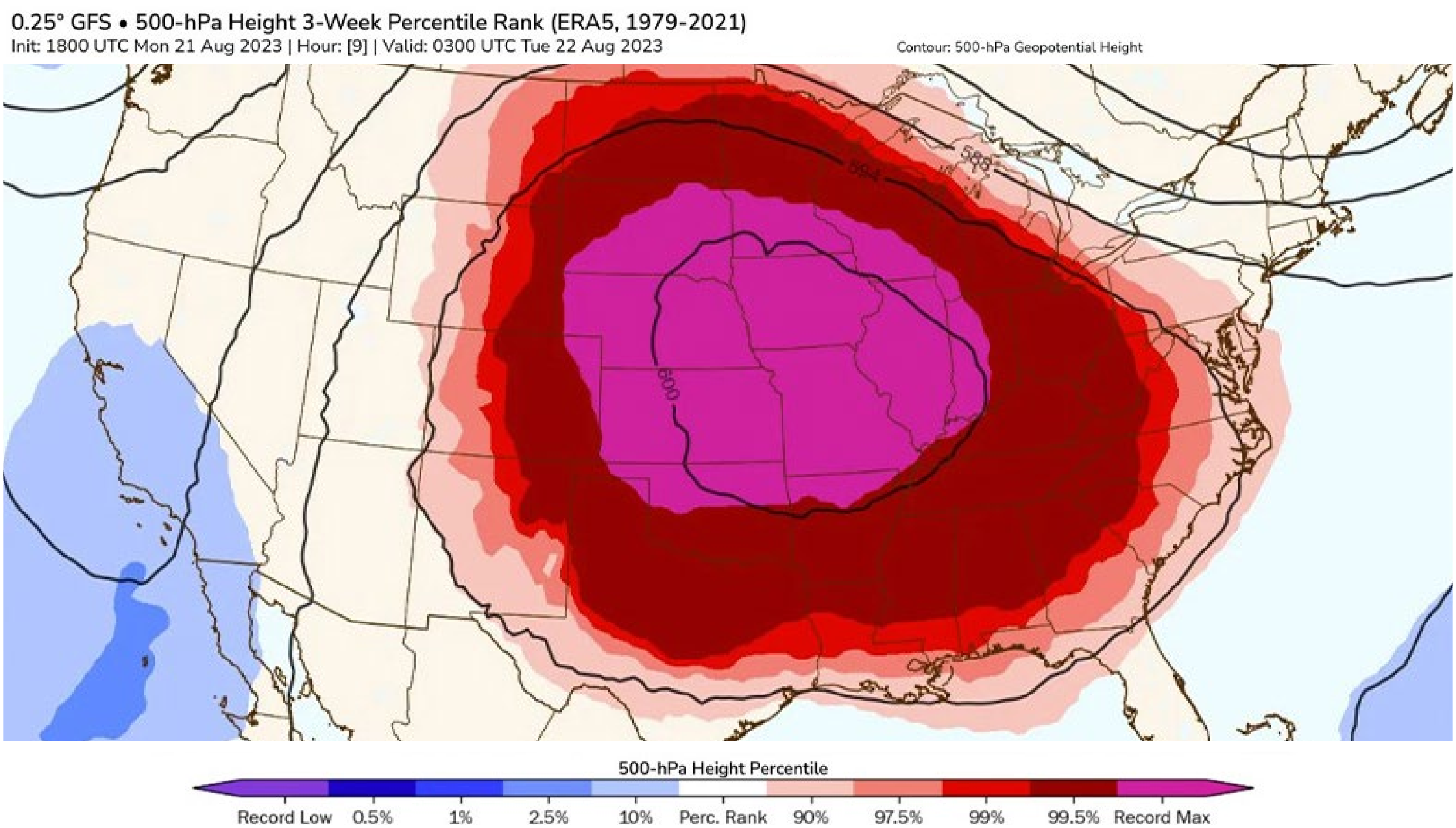
"That's been really challenging. Thankfully, we've had good renewable resource penetrations [on peak days]," he said. "We've teetered on [energy emergency alert 1] where it's been really close, and a small contingency might have put us there, but we were able to make it through. That's what I'm really calling the new normal."

Tropical Storm Offers Relief to Texas

Tropical Storm Harold gave Texas a bit of a reprieve, with rain in the south and cloud cover elsewhere. Average hourly demand failed to reach 80 GW for only the second time since July 29.

Austin had a 45-day streak of 100-plus-degree temperatures broken when the thermometer only reached 99 F. However, Dallas extended its streak of 100-plus days to 41 on Aug. 22 after having set an all-time high of 109 last week.

ERCOT set another weekend peak demand mark on Aug. 20 at 85.12 GW, not far from the system's all-time high of 85.44 GW. The grid operator was forced to call for voluntary conservation when a large thermal unit went offline. ■



The heat dome has settled over the Great Plains. | *Tomer Burg/PolarWx*

SPP News

FERC Sides with Wind Developer vs. NorthWestern

Upgrade Costs, Rounding at Issue

By Tom Kleckner

FERC last week granted in part, and dismissed in part, Ponderosa Power's complaint that NorthWestern Corp.'s proposal to assign roughly $30 million in network upgrade costs to the wind farm developer violates NorthWestern's tariff and the commission's "but for" cost allocation policy (*EL23-48*).

The agency agreed with Ponderosa that NorthWestern's assignment of the disputed upgrade costs in an optional study that applied a rounding policy is contrary to FERC's "but for" policy and violated the utility's tariff. FERC dismissed the remainder of Ponderosa's complaint as moot because it found for Ponderosa on the issue. It also declined the developer's request to investigate NorthWestern's interconnection queue practices, saying the record doesn't warrant such a review.

NorthWestern's modeling software represents thermal violations in decimal numbers with values to the hundredth decimal point. As a result, loading values between 99.5 and 99.99% are rounded up to 100%, FERC said, which NorthWestern deems to be a thermal violation requiring network upgrades.

Ponderosa is developing a 70-MW wind-powered generation facility that would be interconnected to NorthWestern's transmission system in Montana. It filed a Section 206 complaint under the Federal Power Act in March after studies determined Ponderosa would have to pay the upgrade costs.

The commission found that the optional study results did not demonstrate that the disputed upgrades are required for Ponderosa's project. It said the project's loading value of 99.65% on one line segment did not trigger a thermal overload under the "but for" policy.

FERC said NorthWestern treats the rounding policy "as a practice that is part of its study process" but said it should be more "correctly viewed" as an after-the-fact change that materially modifies and "effectively departs from" the underlying study results.

"The rounding policy's clear effect here is to deem the disputed upgrades to be 'required' for Ponderosa's interconnection, notwithstanding that the optional study results otherwise establish that they are not," the commissioners wrote.

FERC directed NorthWestern to issue Ponderosa within 30 days a revised optional study that removes the disputed upgrades and associated requirements and provides an updated estimate of its network upgrade costs, as the developer requested. ■

FERC has questioned NorthWestern Energy's cost-allocation practices. | *NorthWestern Energy*

Company Briefs

Maui County Sues Hawaiian Electric

Maui County last week sued Hawaiian Electric Company over the fires in Lahaina, Hawaii, saying the utility negligently failed to shut off power despite exceptionally high winds and dry conditions.

The lawsuit claims the destruction could have been avoided and the utility had a duty "to properly maintain and repair the electric transmission lines, and other equipment including utility poles associated with their transmission of electricity, and to keep vegetation properly trimmed and maintained so as to prevent contact with overhead power lines and other electric equipment."

Witness accounts and video indicated that sparks from power lines ignited fires as utility poles snapped in the winds, which were driven by a passing hurricane. The Aug. 8 fires killed at least 115 people and left an unknown number of others missing.

More: *The Washington Post*

Broad Reach Power to be Sold to Engie

French multinational utility Engie last week agreed to a deal with EnCap Energy Transition to acquire battery storage company Broad Reach Power.

Terms of the deal were not disclosed, although the deal includes the assumption of $435 million in debt.

Included in the sale are 350 MW of grid-scale battery assets and 880 MW under construction, primarily within ERCOT. Engie will also gain 1.7 GW of battery storage projects in development and a pipeline of early-stage projects.

More: *Houston Chronicle*

Exxon Predicts World Will Miss Climate Change Targets

Exxon Mobil last week said it believes the global effort to curtail greenhouse gas emissions isn't on track to keep the planet's temperature from rising beyond an increase of 2 degrees Celsius by 2050.

Carbon dioxide emissions stemming from fossil fuels and energy consumption will shrink to 25 billion metric tons in 2050, down 26% from a peak of 34 billion in the current decade, the oil giant said in an annual outlook. Despite the decline, the trajectory would keep worldwide carbon dioxide output well above levels that the United Nations' climate science advisory body says would limit climate change. To achieve the targets, the world needs emissions to drop to 11 billion metric tons on average by 2050, Exxon said.

Exxon has said it would invest $17 billion in coming years to reduce its own emissions and those of customers.

More: *The Wall Street Journal*

Federal Briefs

TVA Reverses Course, Won't Sell Bellefonte Nuclear Power Plant

The Tennessee Valley Authority Board of Directors last week reversed course on a previous decision and rescinded its plan of selling the utility's Bellefonte nuclear plant site.

Matthew Rasmussen, TVA's senior vice president of nuclear engineering and operations support, told the TVA board that Bellefonte is an attractive site for future power production as the agency seeks to double its generation portfolio in the next 30 years.

Currently, there are no specific plans for the property.

More: *Chattanooga Times Free Press*

TVA to Invest $15B Over Next 3 Years

The Tennessee Valley Authority Board of Directors last week approved a $15 billion investment plan that will be phased into various initiatives over the next three years.

TVA is adding 3,800 MW of new generation and has invested $25 billion in existing and new generation over the last 10 years. More than 10,000 MW of new solar energy is expected to be added by 2035, while other investments include $100 million in energy efficiency and demand response programs over the next 10 years.

The board also voted to increase its effective rate to 4.5%, which is expected to cost residential customers about $3.50 more on their monthly bills.

More: *WBKO*

BLM Reserving Land for Proposed Lava Ridge Wind Project

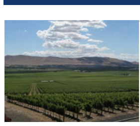
The Bureau of Land Management last week announced that more than 106,000 acres of public lands for the proposed Lava Ridge Wind Project will be kept open for two more years.

During that time, the lands northeast of Twin Falls, Idaho, will not be "appropriated," meaning they cannot be sold or have mining claims filed under public land laws.

BLM has stated that it expects to issue a decision on the application by the fall, but the schedule is subject to change.

More: *Idaho Mountain Express*

West news from our other channels



Large Wind and Solar Farm Panned by Washington State Locals

NetZero Insider

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

State Briefs

CALIFORNIA

Judge Rejects Enviro's Effort to Close Diablo Nuclear Plant

Judge Ethan P. Schulman last week rejected an environmental group's lawsuit that sought to block Pacific Gas & Electric from seeking to extend the operating life of the Diablo Canyon Nuclear Power Plant.

Friends of the Earth sued in April hoping to derail a state-backed proposal to keep the plant running for at least five additional years. The group was part of a 2016 agreement with PG&E to shutter the state's last nuclear power plant by 2025. However, in an 18-page ruling, Schulman dismissed the complaint and agreed with the company that Friends of the Earth was asking the court to "impermissibly hinder or interfere" with state regulatory oversight of the plant.

The operating license for the Unit 1 reactor expires next year, while the Unit 2 license expires in 2025. PG&E intends to apply to the Nuclear Regulatory Commission by the end of the year to extend operations by as much as two decades.

More: *The Associated Press*

COLORADO

Colorado Sues EPA to Stop Public Access to Air Pollution Records

The Attorney General's office last week sued EPA to stop public access to the state's air pollution records.

EPA claims state agencies and citizen watchdogs cannot enforce the Clean Air Act against polluters unless everyone has open public access to the polluters' emissions records. Until state regulators make it easier to find those records, EPA says, it will not fully approve Colorado's required plan on how it will attack ozone and other air pollution problems. Meanwhile, Attorney General Phil Weiser said state health officials believe there is adequate public access to all permits and company reports, and that making access easier would divert state money and staff time from actually fighting pollution.

The current system requires companies holding an air pollution permit to keep the records and make them available to the state "upon request," according to EPA's decision published in the Federal Register. However. states might not do that, EPA said.

More: *The Colorado Sun*

ILLINOIS

Appellate Court Pauses Grain Belt Express Project

The 5th District Appellate Court last week issued an order to stop progress on the Grain Belt Express Transmission Line.

The two-page order stays "any implementation" of a March 8 order from the commerce commission granting the project a Certificate of Public Convenience and Necessity until the court rules on the project's constitutionality. The order stems from an appeal of the ICC order filed by the Illinois Farm Bureau and landowner groups. IFB and the other plaintiffs argued the 2021 state law allowing GBE to apply for and obtain ICC approval for the project violates the special legislation, equal protection and separation of powers clauses of the state constitution.

No date has been set for oral arguments, but briefs in the case will be filed between September and November.

More: *FarmWeek Now.com*

MICHIGAN

Monroe County Nuclear Plant Offline for Non-emergency Situation

DTE Energy last week said it shut down its Fermi 2 nuclear plant after an inspection found leaking coolant.

The situation was deemed a non-emergency by the Nuclear Regulatory Commission, who also said there was no threat to the public.

More: *WTOL*

MINNESOTA

PUC OKs Storing More Nuclear Waste at Xcel's Monticello Plant

The Public Utilities Commission last week unanimously voted to allow Xcel Energy to expand its storage space at Monticello to house an additional 36 canisters of high-grade nuclear waste. Monticello currently houses 30 steel casks of waste in concrete storage structures.

Xcel said it plans to add 14 waste casks at Monticello between 2030 and 2040 if its federal license is renewed. But the company wants space for more if the plant continues running beyond 2040. Xcel has asked the Nuclear Regulatory Commission to re-up Monticello for another 20 years after its current license expires in 2030, but doesn't expect a decision until late next year.

More: *Star Tribune*

NEW MEXICO

AG Takes Legal Action Against Solar Companies

Attorney General Raúl Torrez last week filed against the New Mexico Solar Group for alleged consumer fraud against customers who either fully or partially paid for solar systems that were never installed.

The office also opened investigations into two other companies — Meraki Solar Solutions and Titan Solar — for alleged unfair and deceptive business practices.

NM Solar Group abruptly shut down all its business operations Aug. 11, laying off all employees and blindsiding customers who apparently paid tens of thousands of dollars for solar systems that were never installed.

More: *Albuquerque Journal*

NORTH DAKOTA

Summit Carbon Solutions Reapplies for Carbon Capture Pipeline Permit

Summit Carbon Solutions last week reapplied for a permit for its carbon capture pipeline after proposing to reroute the pipeline 10 miles north of Bismarck and away from areas slated for development.

Earlier this month, the Public Service Commission denied the company's request to build a 320-mile portion of its $5.5 billion pipeline across the state after some political leaders said the route would constrain future residential growth and raise safety concerns.

Summit said the new route addresses "concerns about city growth and future development," as well as the specific issues of three property owners. Altogether, the company said it had made 570 route changes.

More: *Des Moines Register*

OHIO

Four More Townships Ban Solar, Wind Farms in Columbiana County

Columbiana County commissioners last week added Elkrun, Hanover, Knox and Madison to the list of townships banning large solar facilities and wind farms in unincorporated areas.

The approval means 15 of the 18 townships in the county will carry large solar and wind bans. The three remaining townships (St. Clair, Liverpool and Yellow Creek) submitted resolutions for the bans, with commissioners accepting the resolutions. The date for public hearing will be announced this week.

More: *Morning Journal*

PENNSYLVANIA

Berrier Appointed PUC Executive Director

The Public Utility Commission last week announced the appointment of Jennifer Berrier as executive director, effective Sept. 11.

Berrier recently served in various roles at the Department of Labor & Industry, culminating with her December 2020 appointment by Gov. Tom Wolf as the department secretary. Prior to the L&I, Berrier served as Deputy Secretary of Safety and Labor-Management Relations.

More: *PA PUC*

TEXAS

EV Drivers to be Charged Additional $200

The state will start charging EV drivers an additional fee of $200 each year, starting on Sept. 1.

Earlier this year, state lawmakers passed Senate Bill 505, which requires EV owners to pay the fee when they register a vehicle or renew their registration. The cost will be especially high for those who purchase a new EV and must pay two years of registration, or $400, up front.

State agencies estimated that the state lost an average of $200 per year in federal and state gasoline tax dollars when an EV replaced a gas-fueled vehicle. The agencies call the fee "the most straightforward" remedy.

More: *The Texas Tribune*

VIRGINIA

Botetourt County Approves Storage Facility

TESLA

Botetourt County supervisors last week approved a 100-MW storage facility that would use arrays of Tesla batteries to store electricity gathered during non-peak periods.

The facility would be made up of 144 aboveground installations. Each steel unit would be about 8 feet wide, 9 feet tall, and 30 feet long, be equipped with ventilation fans and hold two Tesla Megapack 2XL batteries.

More: *The Roanoke Times*

Dominion Restores Power to Arlington County Following Cable Problem

Dominion Energy

Dominion Energy crews worked much of Aug. 22 to restore power to about 10,000 Arlington County residents following a fault with an underground cable.

Dominion said it had an "underground cable that had a fault," which caused a transformer to lock out. Officials said there were "some flames."

At around 9 p.m., Dominion Energy said it restored power to all customers.

More: *DC News Now*

Dulles to Receive Largest US Solar Airport Project

Dominion Energy and the Metropolitan Washington Airports Authority ceremonially broke ground at the Dulles International Airport last week for what will be the largest renewable energy project ever built at a U.S. airport.

The 100-MW, 200,000-panel solar farm is part of a huge push by Dominion to add 16,000 MW of solar capacity by 2035 as it seeks to comply with a state law requiring 100% of its non-nuclear energy production to be zero emission by 2045.

It is expected to be completed by 2026.

More: *The Associated Press*

Fauquier Supervisors Reject Solar Developer's Appeal

The Fauquier Board of Supervisors last week voted 3-2 to reject Torch Clean Energy's appeal to proceed with a proposal solar facility in Bristersburg.

The board upheld the planning commission's recommendation that the proposal for an 80-MW, utility-scale solar farm is not in accordance with the county's comprehensive plan. Had the supervisors overruled the commission, Torch would have been able to apply for a special exception permit.

Torch has yet to make a final decision on whether it plans to file an amended proposal. If it does, it will go back before the planning commission.

More: *FauquierNow*

WEST VIRGINIA

DEP Approves Operations, Emissions Increases at Belle Explosion Site

dep

The Department of Environmental Protection's Division of Air Quality last week announced it has approved an air quality permit update for Optima Belle's chemical facility in Belle, while also increasing hazardous air pollutant emissions.

Despite heavy public opposition, Division Engineer Jonathan Carney, who signed off on a recommendation to approve the proposal, said "available information continues to indicate" the proposal complies with all applicable state and federal air quality standards.

Meanwhile, Belle residents and air quality advocates objected to what they viewed as the DEP rubber-stamping Optima Belle's proposal without state air monitoring onsite or accounting for the company's role in the 2020 explosion that prompted a shelter-in-place order for a 2-mile radius of the site for four hours.

More: *Charleston Gazette-Mail*