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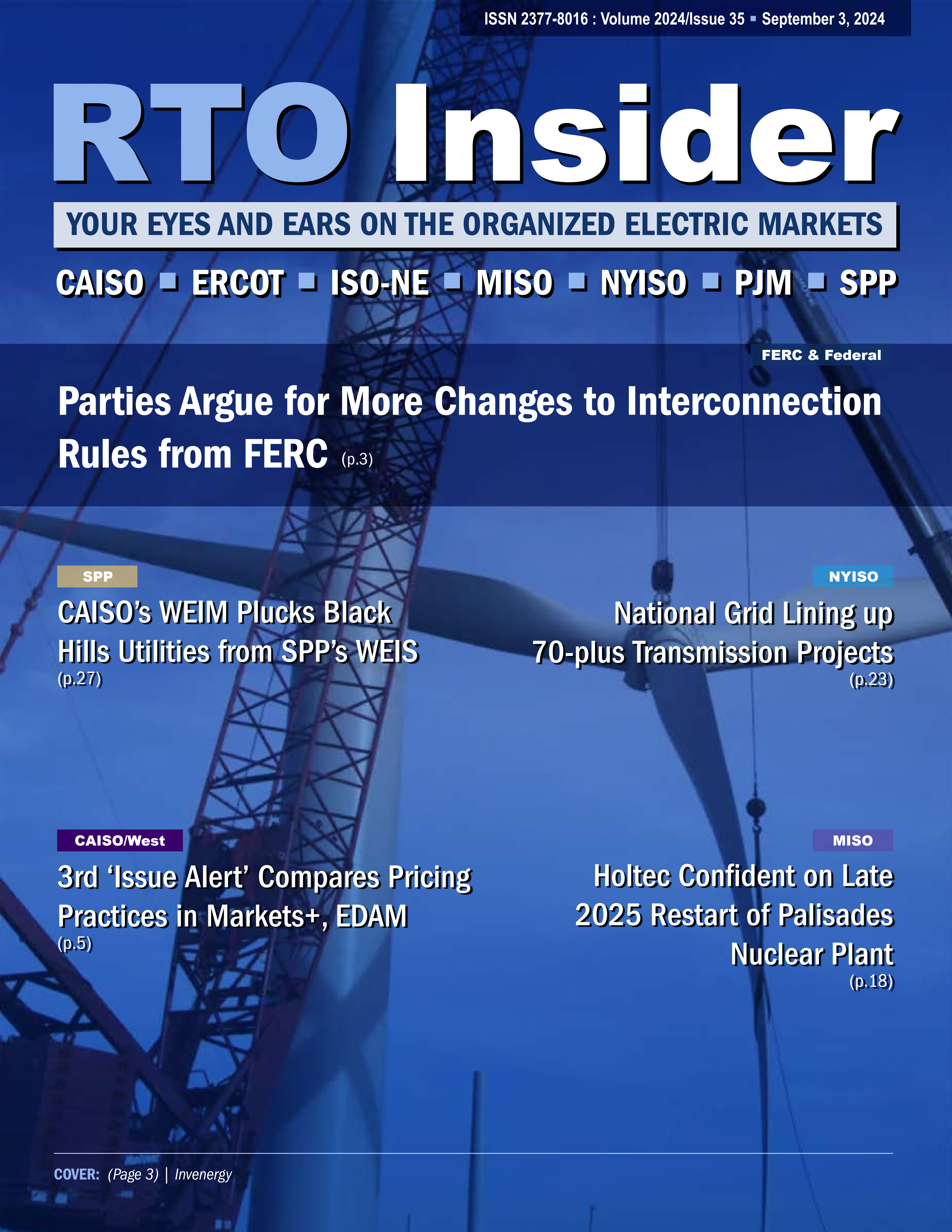

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

FERC & Federal

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RTO Insider
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Sales Development Representative
Nicole Hopson

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

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In this week's issue

FERC/Federal News

Parties Argue for More Changes to Interconnection Rules from FERC

By James Downing

Even as it works to implement Order 2023, FERC is considering additional changes to its rules on generator interconnections, with a *technical conference* set for Sept. 10-11 that saw pre-conference comments filed last week (*AD24-9*).

Commenters argued for a more proactive transmission planning process that takes into account the future generation mix. Others argued for greater automation and certainty around planning.

Some pushed for a special "fast track" for shovel-ready generation that is needed as the grid continually sees generators retire that need to be replaced. The bulk of the new generation in queues is made up of renewable energy; National Grid said that has helped to overwhelm processes originally designed for a more limited volume of fossil fuel-fired plants.

| Invenergy

"Unfortunately, the measures that have been relied on historically — e.g., increased deposits and fees, penalties, and prioritizing first-ready projects — have proven insufficient to address the challenges of a rapidly changing grid driven by unprecedented levels of investment in the energy transition," National Grid said.

Fixing the situation will require new methods, such as a competitive, priority queue for projects that can readily address reliability needs and better coordination between long-term transmission planning and the generator interconnection process, the company said.

"While a capped queue provides an effective means of getting the GI queues under control and more aligned with realistic and effective grid administration, we cannot lose the value that competition in the generation sector has provided for system reliability and consumer costs," National Grid said. "Accordingly, to populate the capped priority queue, our proposal would establish a competitive process based on identified needs to select the projects that would form the relevant queue."

Constellation Energy also supported an expedited queue, noting that ISOs and RTOs have increasingly warned that the trends of accelerating retirements and clogged queues could lead to reliability issues if not addressed in the coming years. Its comments argued for an "Expedited Reliability Process" for reliable, deployment-ready projects, such as uprates to its nuclear plants.

"Constellation has announced approximately 135 MW of planned uprates at our Braidwood and Byron generating stations in Illinois, the equivalent of adding 216 variable-output wind turbines to the grid," the company said. "In total, nuclear operators across the nation are considering or preparing uprates with a cumulative capacity increase of approximately 2 GW."

Such uprates and other shovel-ready projects can plug the reliability gap, but they have to sit in queues that have been gummed up with projects that often contribute far less to resource adequacy, Constellation said. Under its proposal, RTOs would be able to set up an expedited queue when they determine some projects would more effectively and quickly address identified reliability needs.

"RTOs concerned that reliability and/or resource adequacy is becoming an issue could, in these narrow circumstances, seek commission approval of an expedited interconnection study process that would prioritize the processing of interconnection requests likely to be responsive to the RTO's reliability and/or resource adequacy need, and that can demonstrate a high degree of readiness," Constellation said. "This subset of interconnection requests would be moved through the interconnection study process on an expedited basis so they can be put in place quickly in response to the RTO's demonstrated reliability and/or resource adequacy need."

Storage developer Gridstor cautioned FERC against doing damage to the concept of open access in attempting to speed up queues.

"The commission should look to solutions that least compromise open access and make prioritization criteria based as much as possible on the actions and decisions under the control of interconnection customers," Gridstor said.

Rationing interconnection quests to determine advancement introduces a zero-sum process because only some projects would get into the priority queues. It could even lead to discrimination among similar projects, the company said.

In the past, FERC has limited exceptions to open access to new generators using retired units' interconnection facilities and to surplus capacity available to existing generators that want to expand. Gridstor argued the main issue leading to the long queues is a lack of adequate transmission, so any expedited, special processing should be time limited.

"It is imperative that the commission should seek a limiting principle — that is, the smallest compromise to open-access principles needed to achieve the goal of rationing interconnection requests," Gridstor said. "Reforms that go beyond what is strictly necessary to address the current supply-demand imbalance should be rejected, given the more fundamental re-

FERC/Federal News

sponsibility of the commission to uphold open access principles."

Marrying Interconnection and Transmission Planning

The technical conference will also consider arguments around proactively expanding the grid, which would spread the costs of connecting new resources more broadly than they are now.

"Closer integration of generator interconnection and transmission planning processes will result in a more efficient buildout of the electricity grid," Brattle Group Principal John Michael Hagerty said. "The vast majority of transmission upgrades today are identified through siloed processes, based on grid reliability studies (with limited consideration of future resource needs) and generation interconnection studies. Proactive transmission planning processes that holistically account for both future projected demand and changes in the future generation resource mix and consider a comprehensive set of transmission benefits will identify the upgrades that reduce total customer costs and allow new resources to efficiently enter the system through the generator interconnection process."

Hagerty's comments drew from a *report* he co-authored with Grid Strategies for Advanced Energy United and the Solar and Storage Industries Institute on potential changes. It argued that proactive planning will avoid unneeded upgrades identified through siloed reliability studies and result in more cost-effective upgrades that provide access to more new resources.

Such plans need to be based on multiple scenarios to deal with the uncertainty around the future. Hagerty said a reasonable cost-allocation method would also help.

"Proactive planning does not require a specific approach to cost allocation for the new transmission upgrades," Hagerty said. "Identifying a reasonable cost allocation approach that aligns costs with beneficiaries will be an important step in implementing an integrated planning and interconnection process."

Regions could continue to assign upgrade costs to generators, but they would fund a smaller percentage of a larger suite of transmission upgrades developed for their use, he added.

The R Street Institute also argued for proactive planning and broader cost allocation, as it had earlier in FERC's transmission planning rulemaking. Those would lead to lower costs overall, meaning lower bills for consumers.

"This improved efficiency translates into major cost reductions for network upgrades, which consumers ultimately pay for, either directly or indirectly," R Street said. "Because transmission costs are so heavily incurred by consumers, large savings from more efficient network upgrades reduces costs to consumers irrespective of cost allocation method."

R Street cited ERCOT's "connect and manage" system, in which transmission network upgrades are entirely determined in planning, and generator interconnection does not include deliverability requirements, leading to much lower barriers to entry than the "invest and connect" approach used in other markets.

"Transmission costs are borne by consumers, either directly or indirectly," R Street said. "Therefore, it is in consumers' best interests that transmission expansion efforts be most efficient. Separating network upgrades from the generation interconnection process is one way to improve efficiency." ■

CAISO/West News

3rd 'Issue Alert' Compares Pricing Practices in Markets+, EDAM

Latest Notice from Markets+ Backers Examines Differences in Scarcity, Fast-start Pricing

By Henrik Nilsson

Enhanced protections against uncompetitive market behavior are among several tools to ensure fair and accurate pricing under a Markets+ framework, according to an "*issue alert*" published Aug. 28 by 10 entities that back development of the market.

The alert is the third published in a series of seven notices intended to highlight Markets+'s purported advantages over CAISO's Extended Day-Ahead Market (EDAM) and Western Energy Imbalance Market (WEIM). The *first* covered differences between how the two markets would be governed, while the *second* focused on reliability.

The contributing parties include Arizona Public Service, Chelan County Public Utility District (PUD), Grant County PUD, Powerex., Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association, and Tucson Electric Power.

In their third alert, the backers argued that Markets+'s "conduct-and-impact" framework ensures that prices are fair and not distorted by the exercise of market power. The approach is also used in MISO, ISO-NE, NYISO and SPP's RTO, according to the alert.

"Under this framework, a bid is mitigated if it materially exceeds an established reference level and that bid would have a material impact on market prices, absent mitigation," the alert said. "This two-part assessment applies mitigation when needed to ensure market prices are not distorted by the exercise of market power, while providing market participants with flexibility to submit bids that reflect their own evaluation of their costs (including opportunity costs)."

Meanwhile, EDAM's price controls are not as fine-tuned and kick in whenever there is a possibility of price manipulation without a thorough examination, according to the alert.

The Markets+ backers contended that EDAM's approach risks leading to "more frequent, and overly broad, mitigation to price levels that can be below a market participant's actual costs. "

The parties also argued that Markets+ supports reliability and market efficiency by adopting a graduated scarcity pricing method. Scarcity pricing encourages resources to be available during tight energy conditions and helps "ensure prices reflect actual system conditions during periods of tight supply and that customers receive the benefit of the most optimal market clearing solution," according to the alert.

EDAM, on the other hand, does not have a scarcity pricing method designed for its full market footprint, the parties said. Instead, EDAM relies on CAISO's existing pricing method designed to handle shortfalls of ancillary services within the CAISO balancing authority area, the alert stated.

"The effectiveness of this approach is frequently undermined by extensive manual interventions that commonly occur in the CAISO BAA during scarcity conditions, including deploying out-of-market supply and emergency demand response," the parties said. "This behavior puts inaccurate downward pressure on market prices, producing pricing results that are inconsistent with actual system conditions and limiting shorter-term and longer-term market participation incentives."

The alert also highlighted that Markets+ utilizes a so-called fast-start pricing approach, a mechanism that factors the cost of starting and operating gas-fired peaking units into the wholesale market price.

Of the six FERC-jurisdictional organized markets, only CAISO doesn't use fast-start pricing, according to the alert. (See *WEIM Expert Calls for Fast-start Pricing to Address 'Anomalies'*.)

"Failing to include fast-start pricing negatively impacts Northwest and Southwest ratepayers, and impedes long-term efficiency by discouraging investment in new flexible resources and storage that could displace the use of gas peaking units in the future," the parties said.

The parties similarly targeted EDAM's approach to virtual bidding, noting that it's not automatically applied across the entire market but is an optional feature each BAA can adopt.

"This BAA-by-BAA approach introduces uncertainty for load-serving entities and other market participants on their ability to hedge real-time energy costs across the market footprint, potentially limiting the tools that can support market efficiency in EDAM," the alert stated. ■

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

CAISO/West News

Colorado PUC Adopts Rules for Utility Participation in Markets

Decision Comes amid Heated Battle Between EDAM and Markets+

By Elaine Goodman

Colorado's investor-owned utilities must compare available alternatives when asking regulators for approval to participate in an RTO or ISO, under *a decision* by the Colorado Public Utilities Commission.

The comparison must include "sufficient modeling and other analytical support" showing the expected net benefits of participating in a particular RTO or ISO are similar to, or greater than, net benefits from other available options.

But such a comparison is not required when utilities seek approval to join a day-ahead market, the PUC said in its decision, issued Aug. 22.

The decision comes as CAISO's extended day-ahead market (EDAM) and SPP's Markets+ are in a heated battle for day-ahead market participants across the West. Colorado utilities have a choice among EDAM and Markets+, as well as SPP's RTO West, a proposed extension of services offered in the Eastern Interconnection.

The PUC decision, which adopts rules regarding utility participation in organized electricity markets, was prompted in part by *Senate Bill 21-072* from the state's 2021 legislative session. The bill requires transmission utilities to join an organized wholesale market by Jan. 1, 2030.

The PUC's new rules list factors the commission will consider in evaluating a utility's request to join an RTO, ISO or day-ahead market. PUC Chairman Eric Blank, who was the hearing commissioner in the case, issued a recommended decision in June.

Ten groups then filed a joint request to modify the decision to include a comparison of alternatives in evaluating a request from investor-owned utilities to join an RTO, ISO or day-ahead market. They asked that the comparison of benefits be based on "a nodal mapping of the Western Interconnection and at least three years of simulated market operations."

"We believe that it is impossible for the commission to determine that utility participation is in the public interest without an analysis of the market options that are available to a utility," the commenters said in their joint filing.

The groups that jointly commented include Advanced Energy United, Clean Energy Buyers Association, Interwest Energy Alliance, Western Grid Group and Western Resource Advocates.

Loss of Control

In explaining its decision, the commission said utility participation in RTOs or ISOs raises more concerns than participation in less-integrated offerings such as day-ahead markets.

In an RTO, utilities give up control of their transmission assets and much of their decision-making to a regional governance process, the PUC said. The PUC also cited the need for "timely review" of day-ahead market applications.

The PUC adopted the requirement for a comparison of alternatives in an RTO request but left out the need for nodal mapping that the commenters requested. That way, the commission said, utilities will have "more flexibility in the type of modeling or analytical support that may be used."

Colorado regulators adopted rules regarding utilities' participation in an RTO or ISO, including a requirement that the utility compare benefits of available options. | *JIRSA Hedrick*

In a statement after the decision, Western Resource Advocates said it was pleased with the commission's decision to require a comparative analysis of options for joining an RTO, but disappointed the requirement didn't extend to day-ahead market participation.

The joint request from WRA and other groups noted that "the landscape of Western market footprints is rapidly evolving" as utilities evaluate EDAM, Markets+ and SPP's RTO.

"Because of the highly dynamic nature of market footprints, and the significant impact of these footprints on benefits and risks to Colorado consumers, neither the IOUs nor the commission can truly understand the potential costs and benefits without a comparative analysis of alternative market participation under different footprint scenarios," the groups said in their filing.

Utility Requirements

The decision keeps in place other requirements from Blank's recommended decision for utilities that want to join an RTO, ISO or day-ahead market.

The RTO, ISO or day-ahead market that an investor-owned utility wants to join must have a greenhouse gas tracking and accounting system.

Detailed modeling must show that benefits of joining, such as production cost decreases, reliability improvements and emission reductions, will be greater than the expected costs.

And there must be a plan for efficient dispatch and exchange of energy if there is more than one regional market construct operating or proposed to operate in Colorado.

Additional requirements apply when the request is to join an RTO. For example, the RTO must have a regional resource adequacy construct and a plan for new transmission.

The requirements are simplified for a request from a cooperative electric generation and transmission association. ■

WRAP Members Vote to Delay 'Binding' Phase to Summer 2027

New Plan Spells out 'Gradual Path' for Fully Implementing WPP Program

By Robert Mullin

The Western Resource Adequacy Program's key stakeholder body on Aug. 29 approved a plan that would postpone the start of the WRAP's penalty phase by one year, to summer 2027.

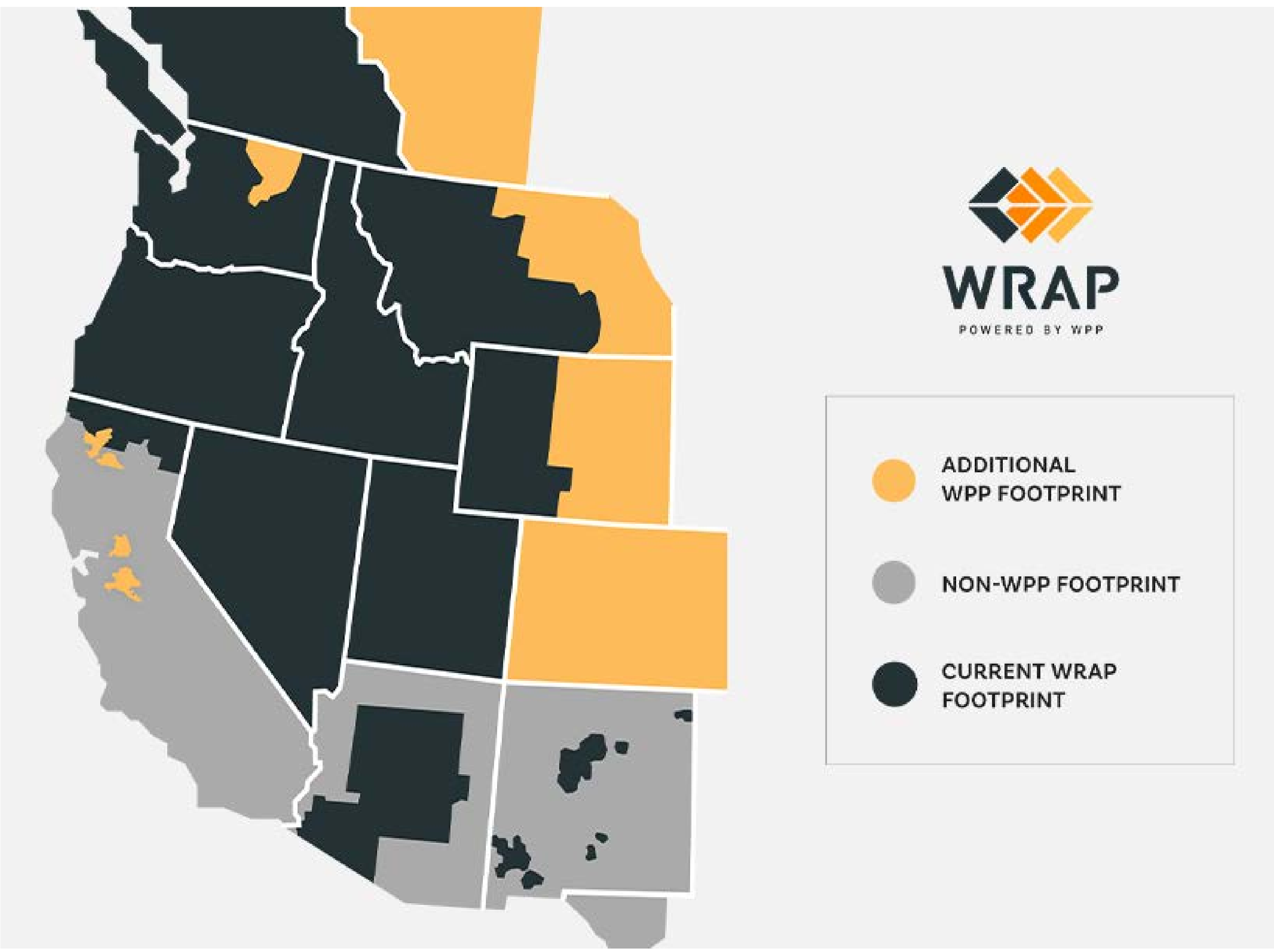
The vote by the Resource Adequacy Participants Committee (RAPC) comes months after committee members issued an April 22 letter seeking to delay the "binding" phase of the voluntary program, which is operated by the Western Power Pool (WPP). (See *WRAP Participants Seek 1-Year Delay to 'Binding' Operations*.)

That letter cited the "significant headwinds" many Western utilities face in securing enough resources to avoid incurring penalties. The difficulties listed included supply chain issues, faster-than-expected load growth and extreme weather events that have "further challenged" regional assumptions about the volume of generation needed to maintain reliable grid operations.

Before circulation of the April letter, WRAP participants faced a May 31 deadline to commit to binding operations for summer 2026. The "*transition plan*" the RAPC approved Aug. 29 "outlines a gradual path to fully implement the WRAP" by pushing back the binding phase deadline and temporarily reducing program penalties for participants short on RA, according to a statement from the WPP.

"The plan helps in three critical ways," WPP CEO Sarah Edmonds said in the statement. "It moves the program forward with participants engaged and committed and on a path to fully binding in 2027, which was essential after the concerns they raised in April. It allows the program to pool resources and provide support for participants in need, helping reliability in the region. And it allows participants to work to address resource adequacy."

Under the new plan, WRAP participants will be required to provide their notice of intent to go binding for summer 2027 by January 2026, rather than the previous deadline of



WRAP members have voted to approve a plan to postpone the program's "binding" phase until summer 2027. | *Western Power Pool*

May 2025.

"The extra time to resolve uncertainties may enable more binding participation. All participants will be binding for winter [2027]/28," the WPP statement said.

The plan also extends the WRAP's "transition period" by one year to March 2029. During that period, participants who enter the binding phase but remain deficient in RA will be eligible to pay a "discounted deficiency charge" if they demonstrate "commercially reasonable efforts" to obtain WRAP Operations Program capacity but still fail to do so, what the program will consider an "excused transition deficit."

"Participants who are deficient and pay the charges would have the same priority access to surplus capacity as other participants in the Operations Program," according to the plan.

'Critical Mass'

The new plan also introduces the concept of "critical mass" into the WRAP, defined as "the participating load volume and participant threshold for a [WRAP] subregion below which participants may participate in a nonbinding manner" after the conclusion of the transition period. The thresholds will be 15 GW of load and three participants for the Southwest/East Diversity Exchange (SWEDE) subregion and 20 GW of load and three participants for the Mid-C subregion on the Northwest.

Accompanying that new concept are WRAP tariff changes that would allow participants in a subregion to choose to be nonbinding for seasons when critical mass is not achieved.

"Once WPP has given notice to participants that their subregion does not have critical mass, such participants will have 30 days to provide notice to WPP if they intend to participate as nonbinding participants for that binding season," the updated tariff would read. "Such notice and election will be given similarly for each season without critical mass participation."

Another change seeks to help participants in either WRAP subregion more easily meet their RA requirements by tapping the potential for "diversity sharing" across the WRAP's entire footprint via transmission connectivity, allowing utilities to count more distant resources in their RA forward showings (FS).

That part of the plan would assume that 500 MW of transmission capacity will be available for south-to-north flows between the subregions in winter, while the same volume would be available for flows in the opposite direction during summer. It would not reduce the WRAP's total planning reserve margin.

"The extent of any reductions in Subregion FS Planning Reserve Margins should not fall below the WRAP Region PRM," the plan said.

WPP also noted that it will work with the operators of CAISO's Extended Day-Ahead Market and SPP's Markets+ to replace the 500-MW figures with "more accurate numbers." Those numbers likely will be significantly affected by the eventual geographical footprints of the two markets. The viability of the WRAP is particularly important for Markets+ because its participants will be required to participate in the program.

Speaking at the spring joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body in Denver in April, Edmonds said WRAP participants were still "unwaveringly committed" to the program and that the challenges utilities face in meeting RA requirements only further illustrate the need for the program.

"The important thing is getting the program off the ground and addressing reliability in the region," Edmonds said in the Aug. 29 statement. "These changes allow us to do that. Everyone can be part of and benefit from the program, while working to add resources to address any deficiencies. Meanwhile, we'll continue to get critical insights about resource adequacy gaps from the nonbinding period."

The transition plan is open for public comment and will be reviewed by the WRAP's Committee of State Representatives before going to a vote by WPP's Board of Directors. The plan's associated tariff changes also must be approved by FERC. ■

CAISO/West News

CAISO IDs More Challenges in Refining Interconnection Process

Transmission Plan Deliverability an Issue for Resources with Long Upgrade Timelines

By Ayla Burnett

CAISO dove into Track 3 of its Interconnection Process Enhancements (IPE) initiative Aug. 28, as staff and stakeholders grappled with how to solve problems related to the proposal's allocation of transmission plan deliverability (TPD).

In California, TPD refers to the amount of transmission capacity needed in an individual study area to allow proposed generation projects in the area to reach their expected deliverability status. CAISO will allocate TPD to the most viable projects in an area, which will then be reimbursed for their needed network upgrades.

The initiative's Track 2 proposal, approved by the board in June, will apply to Cluster 15 of the interconnection queue and beyond, but the ISO is still struggling to address the "unprecedented volume" of interconnection requests for Cluster 14. (See *CAISO Board Approves Interconnection Enhancements Proposal*.)

Although Cluster 14 projects have already been studied, they're "log-jammed" behind major network upgrades, according to the Track 3 *straw proposal*, causing concerns about how to allocate TPD to projects with long lead times.

The ISO's proposal identified three main issues with the TPD allocation process.

The first is related to TPD allocation issues for long lead-time projects with delayed deliverability network upgrades (DNUs). The second involves allocations for projects with long lead-time reliability network upgrades (RNUs). The third is for long lead-time resources that have met defined resource policy goals of the local regulatory authorities (LRAs) in California for specific technologies and project locations.

Ivanpah solar tower and power lines in California. | *Garth Weals, CC BY-SA 4.0, via Wikimedia Commons*

The structure for TPD allocation prioritizes projects that have a power purchase agreement. For those with longer lead times, the window of opportunity to seek an allocation can be several years before network upgrades are complete, making it challenging for such projects to know when to enter the queue. Projects will have three consecutive opportunities to seek an allocation; if they don't receive one, they'll be converted to "energy-only" (EO) projects, which are not included in resource adequacy counts.

Bob Emmert, CAISO senior manager of interconnection resources, said projects with longer timelines and needed upgrades may struggle to execute a PPA.

"It may be difficult for long lead-time network upgrades and long lead-time generation resources to actually get that PPA or be shortlisted before they're converted to energy only, even if the number of opportunities were increased to four," Emmert said during the Aug. 28 workshop. "We want to at least discuss ways that we might be able to rectify that situation."

Proposed Solutions

For projects with long lead-time DNUs, Emmert presented a potential interim solution: increasing the number of PPAs for projects to come online as EO while waiting for Full Capacity Deliverability Status (FCDS).

"We definitely think that offering a pathway for early interconnection for energy-only projects is critical," said Sushant Barave, senior director of grid integration at Clearway Energy Group. "I also think this pathway has to be paired with an interim deliverability framework because that's what makes standalone energy-only projects coming online earlier financeable."

"I would encourage CAISO to think about it as part of the larger solution, where, because of long lead-time upgrades, even projects that have deliverability sometimes cannot get the contractual assurance and show up early on as energy only," Barave added.

Other stakeholders were concerned about the proposal's implications for storage resources.

"I see this being a struggle for storage projects, which are a lot of the projects that are seeking deliverability," said Soumya Sastry, senior manager of structured energy transitions at PG&E. "I think that there would be a lot of challenges from a buyer's perspective. I don't know if we would want to pay the same price for something that is EO."

The proposal also raised concerns about the uncertainty of procuring on such long timelines.

"I think this could lead to potential over-procurement in the reliability space or just stranding projects that there's not a need for this sort of conversion from energy only to FCDS that far in advance," said Michael Freeman, contract origination manager at Southern California Edison. "If you're in a market where you're procuring for long-term assets, how are you judging when a project is going to come online or get RA at year six, year eight, year 10? … It just makes planning for reliability more difficult, and I could see projects that have that sort of option be stranded because LSEs may not want to take that sort of risk."

Emmert reiterated concern about the risks associated with the proposal.

"There may be certain project conditions that are just too risky, and you would not be willing to go down that road. But there may be other projects that the risk profile is less."

Regarding the second issue — projects with long lead-time RNUs — Emmert suggested that contracting with projects that won't be in operation for five to seven more years could enable such projects to obtain a TPD allocation within the three or four opportunities provided.

"From an LSE perspective, if there's a path forward to getting TPD and there's certainty and a robust pool to select from, I don't see an issue," Freeman said.

The third issue considers whether special TPD allocation criteria should be developed for long lead-time resources that meet defined resource policy goals of LRAs. The idea is that unique criteria could allow these projects to avoid the risk of being converted to EO before procurement begins.

"There may be infrastructure such as offshore wind that needs to be put in place before you can even start building it," Emmert said. "The question is, will the central procurement entity be authorized and willing to contract for these resources within the period where these resources are eligible to seek an allocation? Or should we look in another direction to try and solve this problem?"

Stakeholders showed support for the third solution.

"Capacity needs to be reserved for generic long lead-time resources because developers don't invest in remote resource areas where transmission doesn't currently exist and isn't being planned for," said Nancy Rader, executive director of the California Wind Energy Association. "The 10-year timeline for planning and building those is just too far out to enable a PPA, so these resources really need to be treated separately from non-long lead-time resources in the intake process."

The ISO hopes to publish a revised straw proposal for Track 3 by October and is targeting a Board of Governors vote in March 2025. ■

CAISO/West News

Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+

Report Suggests PNM, El Paso Electric not Bound by Arizona Utility Choices

By Elaine Goodman

A new study may dispel the notion that New Mexico utilities must follow the day-ahead market choice of their Arizona counterparts in order to realize benefits from market participation.

The Brattle Group performed the *study* for Public Service Company of New Mexico (PNM) and El Paso Electric (EPE). It compared the projected benefits from joining either CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+. The study models a scenario in which three Arizona utilities — Arizona Public Service, Salt River Project and Tucson Electric Power (TEP) — join Markets+.

Brattle Principal John Tsoukalis presented the study results Aug. 29 during a New Mexico Public Regulation Commission workshop.

PNM's annual benefits would be $20.5 million in the EDAM case, the study found, compared with $8 million from participating in SPP's Markets+. For EPE, projected benefits are $19.1 million a year for EDAM, *versus* $9.1 million for Markets+.

Compared to previous analyses, the new study modeled transmission connectivity in the two day-ahead market options in much more detail, including how third-party transmission rights could be used, according to Kelsey Martinez, PNM's director of regional markets and transmission strategy.

"What we realized through this study is that we do have a choice," Martinez told the commission.

That realization means that factors not included in the study may become more influential in PNM's market choice, Martinez said. She noted the potential operational challenge of having large amounts of wind energy moving through the PNM system.

"One market would be dispatching our resources, and another market would be dispatching all the resources that are using and connected to our system," she said.

Comparing Seams

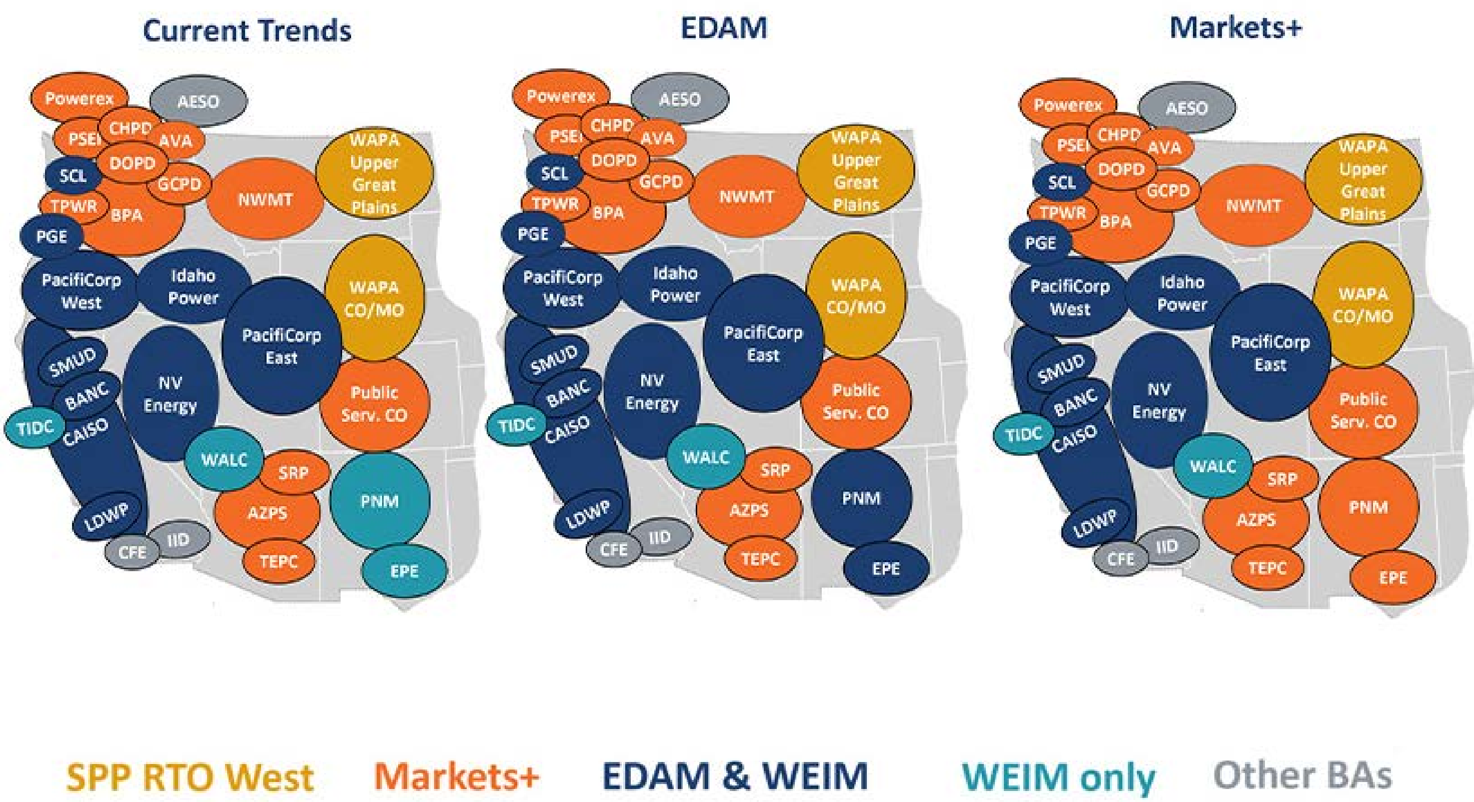
Tsoukalis said the study was designed to look at the impact of two potential seams resulting from a day-ahead market choice.

"One of those key study questions was looking at which seam was worse," he said: "that seam with Arizona, or the seam with all the wind in New Mexico that has off-takers in California?"

Brattle looked at the results of the New Mexico utilities joining EDAM or Markets+ as compared to a "current trends" case, which is "a representation of where we think the WECC could go," Tsoukalis said.

In the current trends case, the Arizona utilities join Markets+ along with a cluster of Northwestern entities, including the Bonneville Power Administration, Powerex and Puget Sound Energy. Western Area Power Administration (WAPA) Upper Great Plains and WAPA Colorado Missouri go with SPP's RTO West in the scenario.

Entities including CAISO, PacifiCorp, NV



The Brattle study examined three different scenarios for EDAM and Markets+ footprints. | *The Brattle Group*

CAISO/West News

Energy, Portland General Electric and Idaho Power would participate in EDAM in the current trends case, while PNM and EPE would remain in CAISO's real-time Western Energy Imbalance Market (WEIM) but would not join a day-ahead market.

Brattle chose 2032 as the study year.

The study found that for PNM, adjusted production costs fall from $55.4 million in the current trends case to $45.4 million in EDAM and $43.9 million per year in Markets+.

Annual congestion revenues are higher in the EDAM case, at $25.6 million for day-ahead and real-time markets combined, compared with $14.3 million in the Markets+ case. Bilateral trading revenue in EDAM is $3.3 million compared to $0.7 million in Markets+, a reduction from $8.6 million in the current trends case.

EPE also sees a difference in congestion revenues between the two cases: $16 million in EDAM *versus* $12.5 million in Markets+, relative to $7.8 million in the current trends case. EDAM also gives EPE a big potential boost to bilateral trading revenue: $14.4 million a year in EDAM compared to $6.6 million in the current trends case. Bilateral trading revenue drops to zero in the Markets+ case.

Because of increased imports from the Four Corners trading hub in the EDAM case, New Mexico "becomes flush with low-cost power," Tsoukalis said. EPE then has an opportunity to sell that power to TEP in the Markets+ footprint.

In response to a commission question, Tsoukalis said Brattle did not study a case in which TEP or the other Arizona utilities joined EDAM, saying the results would be almost a "no-brainer."

"I tend to think it would skew the benefits more for EDAM, of course, by adding more to that footprint," he said.

Building Transmission

Scott Dunbar, a partner with Keyes & Fox representing the Clean Energy Buyers Association, asked whether congestion revenues projected for the New Mexico utilities in the EDAM case were likely to fall as new transmission is built.

Tsoukalis said the congestion revenue is a signal that more transmission, or greater availability of transmission rights, would be valuable. He said more transmission would shift a number of metrics.

"If you build more transmission, my intuition would be that benefits would go up overall," Tsoukalis said. "It just might shift from congestion revenue to adjusted production cost reduction."

Emmanuel Villalobos, EPE's director of market development and resource strategy, said the company is still reviewing details of the Brattle study. But a big takeaway was the $14 million in potential revenue from bilateral trading in the EDAM case.

"[It's] really enough to kind of sway [us] back and forth between the EDAM decision and the Markets+ decision," he said, noting the figure was potential revenue and not guaranteed.

EPE will weigh other factors such as governance and start-up costs in its day-ahead market decision. And the company may ask Brattle for analysis of additional scenarios, which could include EPE and PNM choosing different markets.

The PRC's Aug. 28 meeting was the third workshop the commission has held on regional markets. Commissioner Gabriel Aguilera said he now plans to work with his staff on a set of guiding principles for market participation, which will come to the full commission for a vote. ■

ERCOT News

PUC Shortlists 17 Projects for Loans from Texas Energy Fund

By Tom Kleckner

The Texas Public Utility Commission has selected *17 generation projects* for further review as part of a $5 billion loan program intended to add dispatchable, or thermal, generation to the ERCOT grid.

During its Aug. 29 open meeting, the commission delegated authority to its executive director to enter into loan agreements with those applicants who can show "they're worthy" after a due-diligence review. The projects, if completed, would add 9.78 GW of new dispatchable generation for $5.38 billion in state loans (56896).

The portfolio was culled from 72 applications under one of four *Texas Energy Fund* (TEF) programs approved last year by voters, the In-ERCOT Generation Loan Program. The applications sought more than $24 billion in low-interest funding for projects representing over 38 GW of dispatchable generation.

PUC staff and the TEF administrator *assessed each of the applications* based on applicants' experience and financial strength, the proposed projects' technical and financial attributes, and five commission priorities: diversity among applicant types, diversity in siting location, speed to market, ability to relieve transmission constraints and diversity of resource type.

"I'm happy with the recommendation. I think it's an amazingly good job of weighing all the issues that the five commissioners brought to you throughout this process," PUC Chair Thomas Gleeson told staff during the open meeting.

Should any projects fail the due-diligence review, staff could recommend additional applications for review. However, there is a March 2025 deadline to advance those projects for review. Initial disbursements for approved projects will be made before Dec. 31, 2025.

The list of 17 projects includes heavyweights like Calpine, Constellation Energy, NRG Energy and Vistra. It also includes local entities like Kerrville Public Utility Board and Rayburn Electric Cooperative. The projects range in size from 1,350 MW to 122 MW.

"We had 72 folks who were interested and wanted to, if you will, kind of get in the game," Commissioner Jimmy Glotfelty said. "They put a lot of thought into it and hopefully ... there'll be an opportunity for more to come."

"We are eager to see these projects break ground and are confident that the commission will proceed in such manner to ensure that the fund is used efficiently to deliver the reliable power," Tony Bennett, CEO of the Texas Association of Manufacturers, said in a statement. "Texas needs to maintain its top spot as the best place to do business, grow jobs and strengthen communities."

The TEF's other programs include the completion bonus grants, outside ERCOT grants and the Texas backup power package. The fund was established in March because of *state legislation* that passed last year, with the February 2021 winter storm serving as the catalyst. The PUC says the program can support up to 10 GW of new or upgraded generation capacity in ERCOT. (See *Texas PUC Establishes $5B Energy Fund*.)

Stoic Energy principal and ERCOT observer Doug Lewin said in his weekly newsletter that 80% of the gas plants will be peakers and "will likely displace older, higher-polluting fossil fuel plants."

"This was not unexpected, but it's interesting to see that's what actually happened," he wrote, noting that gas availability was a "major problem" during the 2021 storm. ■

Constellation hopes to add eight gas-fired units at its Wolf Hollow facility southwest of Fort Worth. | *Constellation*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Luminant's Ned Bonskowski raises an issue as Engie's Bob Helton listens. | *ERCOT*

Real-time Co-optimization Go-live Date Could be Accelerated

ERCOT has told stakeholders it may move up the real-time co-optimization project's go-live date from its previous September 2026 target, welcome news about a mechanism that will be integral to the future market design.

"We're not going live in September 2026. It's well ahead of that," ERCOT's Matt Mereness, chair of the Real-time Co-optimization + Battery Task Force (RTC+B), told the Technical Advisory Committee during its Aug. 28 meeting. "There is a possibility for getting this in by the end of 2025. By next month at this time, we should have a better feel for what that date is."

Mereness said several sequenced issues need to be resolved before going live. They include parameters for ancillary service (AS) demand curves, readying the real-time co-optimization (RTC) simulator and market readiness.

"We're on the eve of having the project schedule. Some of the details are still working out," he said.

Cautioned by stakeholders that RTC's go-live date could have a large effect on forward prices, Mereness agreed.

"I think part of it is, will the program have a date? And then there's the risk management around it ... what are the dates that have the confidence in it?" he said. "So yes, that's part of the vetting process."

RTC is used by most other grid operators in North America and has been on ERCOT's market design and policy radar for more than 10 years. The market tool procures energy and ancillary services every five minutes, automating many processes that currently are managed manually.

A previous task force, also chaired by Mereness, secured approval for seven nodal protocol revision requests (NPRRs) and two other changes that will guide the tool's implementation. The task force was disbanded in 2020, but the disastrous 2021 winter storm put further work on hold until 2023. (See "RTC Stakeholder Group to Form," *ERCOT Technical Advisory Committee Briefs: July 25, 2023*.)

ERCOT's Independent Market Monitor released a *report* in 2018 that evaluated RTC's effect on the market. Using 2017 as its simulated operating year, it found a $1.6 billion reduction in total energy costs; an $11.6 million reduction in production costs to serve load; a $257 million reduction in congestion costs; a $155 million reduction in AS costs; and reliability improvements due to a reduced overloading of transmission constraints and a decrease in regulation up.

TAC Tables Remanded NPRR

Members agreed to table a nodal protocol revision request (*NPRR1215*) after it was remanded back to TAC by ERCOT's Board of Directors to correct an error that led to its withdrawal. (See "Error Forces NPRR's Withdrawal," *ERCOT Technical Advisory Committee Briefs: July 31, 2024*.)

Staff said they pulled back the NPRR after they found an error in its formula calculation. They said they have since discovered potential issues that need further investigation and requested it be tabled.

The rule change clarifies that the day-ahead market energy-only offer credit exposure calculation zeros out negative values.

TAC also will have to take the bifurcated part of a Nodal Operating Guide's rule change (*NOGRR245*) that was partly approved by ERCOT's Board of Directors Aug. 20. While approving voltage ride-through requirements for inverter-based resources (IBRs), the directors ordered that a board priority NOGRR be drafted to clarify hardware modification requirements and exemption standards and processes. (See *ERCOT Board of Directors Briefs: Aug. 19-20, 2024*.)

The subsequent rule change will address more details around NOGRR245's exemption process, including the ability to supplement information if a resource entity makes an exemption request by April 1, 2025; appropriate criteria for some level of hardware upgrades for a "vintage" resource to meet relevant ride-through performance requirements or whether it be granted an exemption; and details about the reliability assessment process.

TAC Chair Caitlin Smith, with Jupiter Power, said ERCOT staff is waiting until the Public Utility Commission approves NOGRR245, likely during its Sept. 26 open meeting, before beginning work on the bifurcated portion. Staff hope to bring a final version of the subsequent NOGRR to the board's February meeting to meet the April 1 deadline for exemption requests.

"Having something that's done and approved and implemented by April, that's a big lift," Luminant's Ned Bonskowski said. "I'm not saying we can't do it. I just want us to be honest with ourselves about what's possible."

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Smith voiced similar concerns to the board during its August meeting.

Ancillary Services Workshop

Following the morning TAC meeting, members gathered again in the afternoon for a workshop on the PUC's ancillary services study. The commission will use the study in reviewing the type, volume and costs of the grid operator's four AS products and evaluate whether additional services are needed (*55845*).

The PUC asked both ERCOT staff and the IMM to collaborate on the study. They reviewed AS products for reliability needs and improvements in their procurement to improve efficiency and lower costs.

Staff aren't recommending additional AS products for the time being. However, it has proposed exploring two potential improvements: developing a probabilistic method to calculate the appropriate quantities of non-frequency responsive non-spin and ERCOT contingency reserve service (ECRS); and determining the final AS quantities closer to the operating day, rather than annually.

The IMM used a model with a random probability distribution to perform its analysis. It found ECRS and non-spin quantities can be "substantially" reduced while maintaining reliability. The monitor said a 1-in-10 reliability standard still can be satisfied with 50 and 35% reduced procurements for ECRS and non-spin, respectively.

A draft study will be filed at the PUC by October, opening a comment period for stakeholders. The PUC will host a workshop on the study Oct. 31.

Lightening the Mood

American Electric Power's Richard Ross, who

ERCOT's Matt Mereness | *ERCOT*

also sits on SPP's Markets and Operations Policy Committee and does his best to boost the levity in both committees, offered Smith a method to lighten the mood among members.

"I understand someone said earlier we don't have fun in these meetings anymore. One of the things some of us do is force the group in unison to read the [antitrust] attestation at their own pace," he cracked. "It does give us a smile opportunity, should you feel the need to amp up the culture of the meeting."

Smith responded that she was open to Ross' suggestion.

"I was just told that at TAC, unlike SPP, we don't have 'cookies and laughter,' so we will work on that," she said. "Someone else said we do have snickering, so with that, let's get started."

Consent Agenda OK'd

TAC endorsed a combo ballot that included three NPRRs, one NOGRR and a single change to the Retail Market Guide that, if approved by the ERCOT board, will:

- *NPRR1221*, *NOGRR262*: Align manual and automatic firm load shed provisions; clarify the proper use and interplay of under-voltage load shed, under-frequency load shed and manual load shed; and address reliability concerns over the extent of transmission operators' manual load-shed capabilities.
- *NPRR1227*, *RMGRR181*: Align defined protocol terms and add five definitions ("acquisition transfer," "decision," "effective date," "gaining competitive retailer" and "losing competitive retailer") that previously were located in the Retail Market Guide (Acquisition and Transfer of Customers from one Retail Electric Provider to Another). The NPRR also replaces the broadly titled terms "decision" and "effective date" with the specific terms "mass transition decision," "acquisition transfer decision," "mass transition effective date" and "acquisition transfer effective date" to provide clarity. The change also expands the "gaining competitive retailer" and "losing competitive retailer" definitions to apply beyond the mass transition and acquisition transfer processes.
- *NPRR1236*: Reflects Real-Time Co-optimization Plus Batteries (RTC+B) Task Force's modifications to the reliability unit commitment capacity-short calculations and addresses limits in the current calculations by considering ancillary service sub-types. It changes the calculation process involving regulation down service and addresses changes required to align protocol language with recently approved NPRR1204 (Considerations of State of Charge with Real-Time Co-Optimization Implementation). ■

— Tom Kleckner

ISO-NE News

Mass. DPU Approves 1st Round of Utility Grid Modernization Plans

By Jon Lamson

The Massachusetts Department of Public Utilities has approved grid modernization plans from electric distribution companies that outline longer-term strategies for handling increased electrification and the deployment of distributed resources.

The electric sector modernization plans (ESMPs) include five- and 10-year load forecasts, investments to meet forecasted demand and boost resilience, and cost-benefit analyses for the proposed investments. Overall, the plans predict major new costs for ratepayers. (See *Mass. Utilities Submit Grid Modernization Drafts*.)

The plans were mandated by 2022 *legislation* requiring utilities to submit new ESMPs every five years, along with two reports per year providing updates on investments and forecasts.

"The department expects the ESMPs to be each utility's roadmap outlining how the discrete investments proposed will achieve the statutory objectives," the DPU wrote in its Aug. 29 *ruling*.

The DPU largely accepted the utilities' proposals, despite concerns raised by the Massachusetts Attorney General's Office, Department of Energy Resources, and several environmental and consumer advocacy groups.

While the *Grid Modernization Advisory Council*, a stakeholder group set up to provide recommendations on the plans, advised that the ESMPs "should be the central distribution system planning document" for "whole-of-business" electric utility planning, the DPU rejected this suggestion.

"This approach would add requirements that the 2022 climate law does not envision," the DPU ruled, writing that their review of the plans "is limited to the new, discrete and incremental investments proposed in the ESMP."

The department did note the difficulties "regarding the need to monitor and attempt to influence multiple department proceedings that touch upon distribution system planning." It wrote that it "sees value in the companies reporting high-level, informational-only data in the ESMP reports relating to non-ESMP investments."

The investments proposed by the utilities are significant: Eversource Energy presented more than $600 million in additional spending over five years, while National Grid proposed more than $2 billion. The mounting costs are in part a reflection of projected growth in peak demand. Eversource anticipates a 21% increase in electricity demand over the next 10 years, while National Grid forecasts about a 29% increase.

The department's approval of the plans is not a preapproval of the investments. The DPU wrote in a February 2024 *interlocutory order* that it will review the proposals "in the context of strategic planning documents only."

The Massachusetts State House in Boston | *Shutterstock*

However, the scale of the investment spurred concerns from advocacy groups and the AGO, which wrote that "the magnitude of the planned EDC investments is a sobering challenge to ratemaking and to affordability for ratepayers."

Representatives of climate and environmental justice organizations expressed disappointment that the DPU did not take a broader approach to the ESMP proceeding.

"I wish they had gone further," Kyle Murray of the Acadia Center told *RTO Insider*. There were "not a lot of significant changes from what the companies proposed," and the DPU "didn't take a lot of suggestions from the intervenors."

However, Murray said the move toward long-term planning is a step in the right direction, and he applauded the DPU's decision to lengthen the stakeholder process for the next round of ESMPs.

Larry Chretien of the Green Energy Consumers Alliance said the DPU's decision not to use the ESMPs as central planning documents could make it difficult for the department and intervening organizations to evaluate and engage with proposals across separate dockets, filings and stakeholder advisory groups.

"The oversight is going to be tremendous, and it's going to be every year," Chretien said. "It's just not practical to think that the public interest groups and the EJ groups will have the bandwidth to play this game over time."

Demand Forecasting

The AGO and the DOER both expressed concern about deficiencies in the utilities' load growth forecasts, writing that they lack consistent inputs and do not account for certain peak load reductions strategies.

"The forecasts offered by the companies fail to meet the standards established; are not transparent; are not comparable across the companies; do not provide a full accounting for underlying assumptions; and lack consideration of important tools like load management, which can reduce costs for ratepayers," the DOER *wrote*.

The department argued that the EDCs appear to underestimate the potential of peak demand reduction strategies including managed electric vehicle charging, new rate designs,

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new building codes and energy storage.

The DPU ruled that ESMP load forecasting complied with the law, and that variance between the utilities' approaches could help accommodate differences in the characteristics of their respective service areas.

"The department finds that each company's forecasting method and assumptions are reasonable, appropriate and reliable," the DPU found.

To evaluate the accuracy of future forecasts, the DPU directed the companies to include a comparison of forecasted and actual demand in their biannual filings, and to compare their ESMP five- and 10-year forecasts with their more recent figures. The DPU also required utilities to include separate modeling of demand reduction and energy efficiency programs in the next round of ESMPs.

Climate Resilience

The state's 2022 climate law also required utilities to detail their plans to prepare the grid for the effects of climate change. The DPU determined the utilities' proposals complied with the requirements of the law but found "the need for greater consistency in the climate vulnerability assessments prepared by the utilities."

The DPU noted the utilities proposed different horizons for their climate projections and included limited detail on how they plan to mitigate the risks identified in climate vulnerability assessments. It directed utilities to identify resilience investments using "major event-inclusive performance data" to analyze cost-effectiveness and account for the location of critical facilities.

"In their biannual ESMP reports, the companies shall provide updates on their progress toward finalizing their frameworks for climate vulnerability risk assessments as well as on their targeted resiliency investment identification and prioritization method," the DPU wrote.

Gas Planning

Environmental advocacy groups expressed concern that the plans do not include enough information on coordinated gas-electric planning and wrote that aspects of the plans citing the potential of hybrid heating systems and blending alternative fuels in the gas network are not compliant with a recent DPU order on the future of gas (20-80-B). (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

The DPU wrote that it cannot rule on the viability of the gas companies' decarbonization strategies in the ESMP proceeding, and that it will evaluate these proposals when the companies submit their Climate Compliance Plans in spring 2025.

The department did note that it expects the EDCs to be compliant with orders on gas decarbonization in ESMP filings and directed the companies to "account for any future department decisions on the propriety of these technologies in their future ESMPs." ■

MISO News

Holtec Confident on Late 2025 Restart of Palisades Nuclear Plant

By Amanda Durish Cook

No nuclear power plant in the nation has restarted operations after shutting down, and Holtec International is detailing how it expects to accomplish the feat at the mothballed Palisades Nuclear Generating Station in a little more than a year.

Holtec, which provides decommissioning services and equipment for reactors and waste, has completed all submittals necessary for the U.S. Nuclear Regulatory Commission to consider authorizing a repower of the dormant Michigan plant. The company has notified the NRC of its intent to file for and submit all necessary documentation to secure a 20-year license extension so Palisades can generate power into 2051. The NRC said it plans to issue a draft report in early 2025 and release a complete report by mid-2025.

In an interview with *RTO Insider*, Nick Culp, senior manager for government affairs and communications at Holtec, said although Holtec expects NRC staff to be "very thorough in their review and oversight processes, we remain confident in our approach to seek reauthorization of power operations within the NRC's existing regulatory framework."

Culp said Holtec is optimistic Palisades will be generating output in October 2025. The NRC has told Holtec it expects to dedicate a full-time inspector to the site by December, Culp added.

A Model for Other Mothballed Plants?

Although it hasn't restarted the 53-year-old plant yet, Holtec isn't foreclosing subsequent license renewals beyond the 2051 timeline, and Culp said Palisades could become a model for reopenings at other plants.

"This is something we believe could be replicated at other shuttered nuclear plants, both here in the U.S. and abroad. We've seen that when nuclear power goes offline … fossil fuels are often used to backfill the demand for reliable baseload generation," he said. "And as states like Michigan and the country seek to transition away from fossil generation, there's been a renewed focus on nuclear being an important part of our future generation mix."

Culp said Holtec's original intent when it acquired the plant from Entergy in 2022 was to apply its business model of "safe but accelerated nuclear decommissioning" on Palisades. The company determined at the time the plant's

The Palisades nuclear plant in Covert, Mich. | *Holtec International*

approximately $570 million decommissioning trust was sufficient for it to tackle the process.

Three years ago, Michigan Attorney General Dana Nessel argued unsuccessfully before the NRC that Palisades' trust was about $200 million short of full decommissioning cost needs.

Holtec is decommissioning three nuclear power plants on the East Coast: Oyster Creek Generating Station, Pilgrim Nuclear Power Station and Indian Point Energy Center.

Culp said Holtec rethought their tactic with Palisades once they heard a "strong desire" from the community and state government to keep it open, particularly from Michigan Gov. Gretchen Whitmer (D).

"Historically, the support for Palisades in the local community has been strong. Shortly before the plant was to shut down, there were calls from the local, state and federal levels to stay online," Culp said. "Things changed before the plant closed, as there was a recognition that if we want to be serious about addressing climate change and keeping the lights on, nuclear is an essential part of the equation. When Holtec became owner, there was already talk of the plant reopening."

Nevertheless, Holtec began doing some early-stage decommissioning work when it came into possession of the plant in 2022.

"Nothing done in the early stages of decommissioning was irreversible," Culp said, adding that Holtec first focused on cleaning up some spent fuel and recycling old equipment but made sure plant systems and equipment were preserved.

Culp said Holtec stopped drawing from the decommissioning trust as soon as it was inclined toward a reopening.

"As we shifted to a restart, we stopped pulling from that trust fund," he explained. "The decommissioning trust is very sacred and only used for decommissioning-related activities. It will stay bound with the site and continue to grow over the course of plant operations."

Culp did not disclose the total cost of restarting the plant and only said Holtec is making a sizable investment. The company's contribution — paired with a recent $1.5 billion conditional loan from the Department of Energy as part of the Inflation Reduction Act and the state of Michigan contributing $300 million in grant funding — means that decommissioning is the cheaper option by a long shot. (See *LPO Announces $1.52B Loan to Restart Palisades Nuclear Plant*.)

"We're doing a lot of investment to prepare the plant for future operation. But it's substantially cheaper to bring this plant back online than build new generation from a value proposition," Culp said.

Culp said the federal government is doing its due diligence to make sure Palisades is a good choice for the loan, which is essential to restoring operations.

"I would say it's a critical part of it. If it were not for the federal government, state of Michigan support, our long-term power purchase agreements and our own investment, if it weren't for those four funding streams, this would not be possible."

When Palisades comes online, Culp said 100% of its 800 MW output will be spoken for between Wolverine Power and Hoosier Energy Cooperative in power purchase agreements that will span "more than the next 20 years." Culp declined to outline how many megawatts each utility has signed on for, but confirmed Wolverine is the primary offtaker.

Condition, Workforce, Fuel Contract

Todd Allen, chair of the University of Michigan's nuclear engineering program, said the most crucial aspects of restarting the plant include the material condition of the plant, recruiting a trained workforce and a fuel contract. He said the "right number of trained staff to operate this plant" is imperative.

"They're going to have to make a convincing argument to regulators that nothing has changed," Allen said in an interview with *RTO Insider*. "If you stopped running your car for three years … you would want to know, 'do I want to put in new lube oil?' Those are the kinds of questions that they will have to answer."

Allen said if all those pieces are in place and NRC Chairman Chris Hanson can deliver a review within the year as promised, Holtec "might" be able to pull off a restart in 2025.

Allen said when previous owner Entergy put the plant on a pathway to decommissioning, the company likely deferred some maintenance, stopped buying fuel and thinned or scattered staff to other worksites. He said in order to convince the NRC to reinstate a license, Holtec will have to prove the plant has recovered fully from inactivity.

Culp acknowledged that near the end of Palisades' 50-year run, Entergy deferred some maintenance that otherwise would have occurred if the plant was intended to keep operating. He said Holtec is tackling some of the plant's cobwebs and just finished a deep cleaning of its primary coolant system. He also said some components of the plant have been sent offsite for refurbishment for the first time ever, and modular trailers are parked on site to conduct cleaning and inspection of steam generator tubes.

Culp said before Palisades' shutdown, it achieved record-breaking production runs and was operating at the highest safety ranking by the NRC, a testament to the "excellent shape Palisades is in."

Holtec is devoting itself to making sure Palisades has a talented workforce at the ready, Culp said.

"When we shut down, we kept a little more than a third of our workforce," he said. "Since we've started to rehire, we've had a number of previous employees return."

Culp said since the beginning of the year, Holtec has hired about 260 employees, including many former plant employees, bringing Palisades' workforce from 220 to 480. He said the plant is on track to be fully staffed with more than 600 people by spring.

"We're also getting industry veterans, we're getting people fresh from the Navy's nuclear training program," he said.

Holtec is approaching local colleges and skilled trade unions for new employees, Culp said, and emphasized that not every job opening at Palisades requires a college degree.

Culp said 26 former licensed operators have completed requalification of their operating licenses, and prospective operators have begun their 18-month training. He said Holtec in late 2023 rebuilt the plant's training simulator, restaffed its training organization and began using an abandoned, onsite training building again.

Returning the plant to service will be "transformational" for the community in southwestern Michigan, Culp said.

"People understand that this is clean energy, this is reliable energy, these are jobs, this is millions of dollars in annual tax revenue. It's a huge economic driver," he said.

Holtec secured fuel early in its restart journey, Culp said. He said the nuclear industry and its vendors, suppliers and trade unions have provided "vital support" for restarting the plant.

Shifting Public Opinion and 'Zombie' Moniker

Allen said the move to clean energy has tipped the scales on nuclear power's public image, citing in particular Michigan's MI Healthy Climate Plan, which calls for 100% carbon-free electricity by 2050.

"I think that the overall context for nuclear both nationally and globally has shifted more in favor over the past five or so years," Allen said.

A recent *survey* from the Pew Research Center backs that claim, finding that 56% of American adults favor erecting more nuclear power plants to generate electricity, up from 43% in 2016.

But Palisades' journey to restore operation faces opposition.

Anti-nuclear nonprofit Beyond Nuclear refers to Palisades as a "zombie reactor," conjuring images of an unsafe and rickety plant being raised from the dead. (See *Beyond Nuclear Leads Protest of Palisades' Potential Reopening*.) The group, along with grassroots organizations Michigan Safe Energy Future and Don't Waste Michigan, *filed* a petition and request for hearing last week with the NRC on Holtec's transfer request for a renewed facility operating license to fire up Palisades. The trio said they also intend to file another petition and hearing request against exemptions needed from the NRC for Holtec to convert its possession-only license into an operating license.

They have called the restart unsafe, expensive and unnecessary, arguing that renewable energy paired with energy storage can fill the need for the plant. They've also said Holtec is inexperienced because it's never operated a nuclear plant before.

Beyond Nuclear argued in an Aug. 28 press release that Holtec has performed a "con job," and pointed out that eight days after Holtec took possession of Palisades in 2022, it already had submitted an ultimately unsuccessful bid for funding to reopen the plant under the Department of Energy's Civil Nuclear Credit program. The group has asked the NRC to revoke its original Entergy-to-Holtec license transfer from 2021 in its entirety.

Allen allowed that doubts over a restart of the plant likely come from those always suspicious of nuclear power.

"The same tension was there probably before they shut. I doubt people with very strong opinions have changed their mind since. If you were always skeptical, then you're probably still skeptical. I don't think you can avoid that tension; it just exists," Allen said. "I can come up with a list of why nuclear power is really great and why it's really limiting. I don't think any single source of energy is perfect on its own. We end up balancing the benefits and the drawbacks."

Allen said residents who live in and around Covert, Mich., on the whole probably are more comfortable with the plant's resumed operations. He also said the plant's large workforce needs are attractive to the community.

Nationally, Holtec is not the only nuclear operator that aspires to run a plant beyond 75 years, Allen said. He noted that the NRC's original, 40-year licenses weren't based on the technical ability of nuclear plants, but modeled after coal plants, which were the closest analog comparison at the time. He said a few other nuclear plants in the country have set their sights on 80 years of operations or more.

"It could still be a good car. You'd just have to do some checks to make sure," Allen said. "Is Holtec asking to do something unique in the aspiration to go to 75 years? The answer is no."

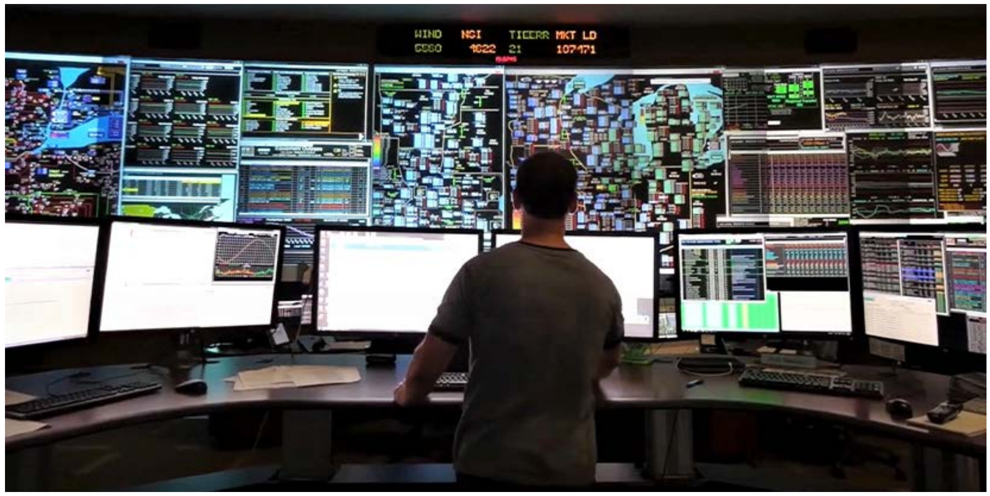
Allen said when Entergy made the decision to shut down the plant, there was less awareness that getting to zero carbon emissions would be so challenging. He also said surging demand growth from data centers complicates the clean energy transformation.

"In retrospect, it might be a bad decision. But at the time, Entergy's decision was really logical. The context is totally different. Today, you have a different economic perspective on your plant," he said. "If you can extend the life of an existing plant, you're financially better off than building new. If you can just change the oil of your car, you're better off than spending $30,000 on a new car." ■

MISO News

Changing System Drives MISO to Scrutinize Guiding Market Principles

By Amanda Durish Cook



MISO control room | *MISO*

CARMEL, Ind. — MISO is conducting a check-in with stakeholders to gauge whether its market design guiding principles are still valid in a changing industry.

The RTO asked stakeholders at an Aug. 29 meeting of the Reliability Subcommittee to evaluate whether its 10-year-old principles are still in lockstep with the functioning of MISO markets.

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

MISO adviser Kim Sperry said MISO references the decisions in its tariff filings to FERC, when designing new market products and when leading stakeholder discussion. "Maybe there's an area where we can make an adjustment," Sperry said.

At the Market Subcommittee meeting, MISO adviser Michael Robinson similarly approached stakeholders. He set the stage by describing 2014's Polar Vortex, which ultimately led to the guiding principles and a redesign of MISO's scarcity pricing.

"The year is 2014, we just incorporated MISO South, operators still [are] getting their feet wet in operating this broader footprint," he said.

Robinson said the near emergency caused MISO to rethink its emergency pricing and led MISO to establish its two-step emergency pricing floors. He said examining the principles now makes sense given the industry's reshuffle.

At the meeting, Clean Grid Alliance's David Sapper suggested MISO consider adding a sector dedicated to industry disruptors, whose innovative ideas could "breathe life into market principles" and further competition. Sapper pointed out that MISO accepts coal interests in its Affiliate Sector, which was created in 2020 and is MISO's newest member sector.

"This might be a missing puzzle piece. The point is not that there's pent-up demand. The point is MISO opening doors," Sapper said. He also suggested MISO include a nod to fairness and social welfare in the principles, something he said is missing today.

Mississippi Public Service Commission consultant Bill Booth said MISO could perform backward-looking check-ins to make sure the new market rules it establishes are effective.

"It'd be nice if our guiding principles included a verification. ... We don't check our work. What do we do after the fact to validate that our theoretical choices are practical?" Booth asked.

MISO staff said their market implementation team was created specifically to check in on whether MISO's proposals are working as intended and perform tests after the fact. Dustin Grethen said MISO has checked in recently on its fast-ramping product and its short-term reserve product.

Sperry said MISO will accept stakeholders' ideas through Sept. 13. ■

MISO News

Late August Heat Wave Delivers 122-GW MISO Summer Peak

By Amanda Durish Cook

CARMEL, Ind. — MISO set its 122-GW summertime peak on the unofficial last week of summer, with widespread heat necessitating back-to-back maximum generation warnings.

MISO *instituted* two separate maximum generation warnings Aug. 26-27 for the Midwest region after issuing conservative operations and a capacity advisory beginning Aug. 25. Much of the footprint registered over 90 degrees on Aug. 26, with a blistering heatwave parked over the Midwest.

"MISO and our members reliably served the highest demand of the summer season due to the extreme heat across our North and Central Regions," spokesperson Brandon Morris said in a statement to ***RTO Insider***. "The declarations we issued allowed us to access the necessary resources to maintain reliability."

MISO said the emergency warnings were due to culmination of the higher-than-normal temperatures, forced generation outages and limited transfer capabilities. As it dealt with the heat wave on Aug. 26, MISO sent reminders to market participants with external resources that their interchange schedules must match their capacity obligations to MISO.

The RTO realized a summertime peak of 122 GW on Aug. 26. At an Aug. 29 Reliability Subcommittee, MISO's John Harmon noted that the peak bested July's high of 118 GW. MISO originally forecasted a summer peak of 123 GW to occur in July. (See "July Peak Prediction Unfulfilled," *MISO Predicts Painless Fall Despite Missouri Capacity Shortfall*.)

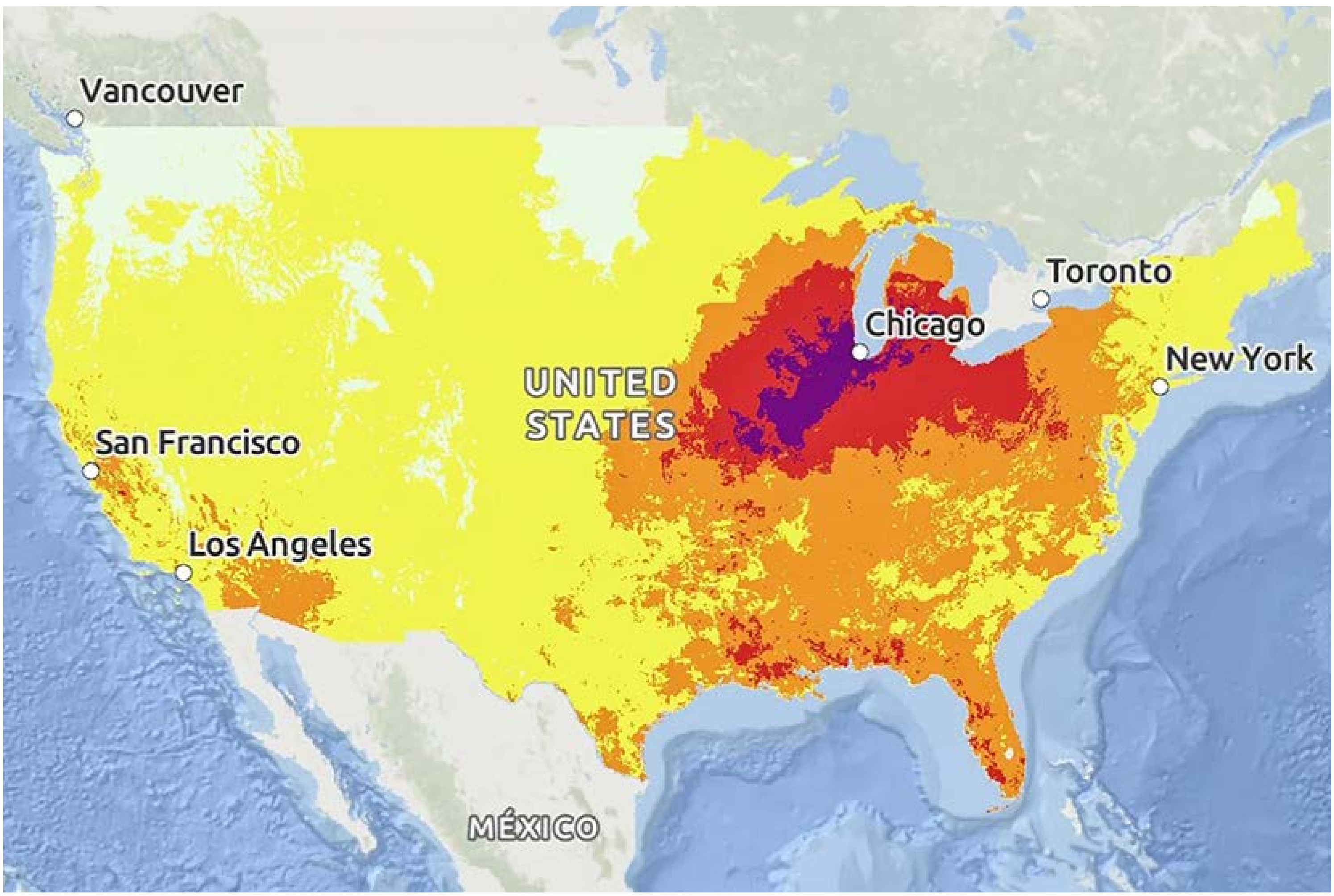
"We did have a couple of maximum generation warnings due to the hot weather and lower than normal wind. We managed through that well," Harmon said. He promised MISO would deliver a more thorough review of the event once it gathers the data for a stakeholder presentation.

Coal and natural gas supplied roughly 70% of demand over the heat wave's most intense daytime hours. While the warnings were in place, MISO also relied on a few gigawatts of imports from PJM, although it, too, was contending with high temperatures.

The situation was helped Aug. 26 by thunderstorms that developed across western Minnesota and moved across central and eastern Minnesota into western Wisconsin.

MISO's growing solar fleet also may have helped the footprint meet demand. The RTO is nearing 7-GW monthly solar peaks.

After Aug. 27, the system returned to normal operating conditions. ■



The National Weather Service heat risk map on Aug. 27 | *NWS and NOAA*

MISO News

TVA Defends Rate Increase for New Gen While Nonprofit Blasts Utility's 'Broken Oversight'

By Amanda Durish Cook

The Paradise Combined Cycle Plant in Drakesboro, Ky. | *TVA*

The Tennessee Valley Authority insists its second rate increase in two years is necessary to build new generation despite the Southern Alliance for Clean Energy condemning the latest hike as clandestine and used to support fossil fuel investments.

TVA's Board of Directors on Aug. 22 approved a 5.25% base rate increase that will take effect Oct. 1. Last year, the board greenlit a 4.5% rise in rates. TVA said the latest increase will amount to an additional $4.35 each month for the average residential bill.

"We don't take this lightly; we know that customers pay bills, not rates. … We recognize that nobody likes increases," TVA spokesperson Scott Fiedler said in an interview with *RTO Insider*. "But this is needed to address the tremendous growth that is happening across our region. We need to build capacity now to keep up with demand in the future."

Fiedler said TVA plans to spend $16 billion through 2027 to add new generation and build out infrastructure to address growth. He said the rate increase will go toward all forms of generation, including new natural gas, renewable energy and investments in the hydropower fleet. But he didn't elaborate on how much will be spent on each category.

Specific investments in TVA's future fleet haven't been revealed. TVA has yet to release its draft integrated resource plan, though Fiedler said the public can expect to see it in the fall. The draft plan was originally expected in the spring.

Fiedler noted TVA went four consecutive years without a rate hike before 2023's increase. He said TVA is emerging from a decade of virtually zero demand growth.

"But now the growth we're seeing isn't stopping," Fiedler said.

Fiedler said the region's population is growing three times faster than the national average and by 2050, the University of Tennessee's Baker School of Public Policy and Public Affairs projects the region's population will have grown by 22%. He said the region will gain in the long run from the economic boom in the form of additional tax revenues.

"The benefits are there, but we understand it can be a hardship," he said.

"We have done everything possible to absorb costs as we invest in the reliability of our existing plants, construct new generation to keep up with growth and maximize solar to produce more carbon-free energy," TVA CEO Jeff Lyash said in a press release after the board approved the increase.

Fiedler said TVA is attempting to blunt the load growth by devoting $1.5 billion to its new energy efficiency program, *TVA EnergyRight*, which offers rebates for things like HVAC checks, new air conditioning units and attic insulation.

He said TVA's efficiency goal is to offset about 30% of the new load coming online over the next decade. He also said TVA has pledged to reduce its internal costs by $900 million over the next three years.

Fiedler also noted that TVA has applied for a grant through the Department of Energy's Grid Resilience and Innovation Partnerships to support a new transmission project to transport renewable energy from the Midwest into the Valley.

By all appearances, TVA's IRP will hinge on new natural gas generation. TVA has announced it will replace two coal units at its 2,470-MW Cumberland Fossil Plant with a 1,450-MW natural gas plant. Early this year, FERC approved a pipeline meant to feed the plant, although TVA has said its decision to build the gas plant isn't final. (See *FERC Approves Pipeline to Supply New TVA Cumberland Gas Plant* and *TVA's Cumberland Coal-to-gas Plans Press on over Resistance*.)

Several clean energy organizations and two Tennessee congressmen have criticized TVA's IRP process as secretive, with little public analysis and inadequate opportunities for public influence. (See *Tenn. Congressmen Introduce Bill to Make TVA IRP Process More Public*.)

The Southern Alliance for Clean Energy (SACE) said TVA's rate increase was likewise shadowy and emblematic of a "broken oversight process." It said board members allowed the hike "without any public documentation showing why the increase is needed or how those additional revenues will be spent."

"Only in the Tennessee Valley could a major utility raise rates without public scrutiny of financial documents," SACE said in a press release, speculating that an "expensive gas expansion is a likely culprit" behind the increase.

The nonprofit said TVA's rate increases this year and last are "strategically set just below a 10% threshold that would trigger renegotiation of hundreds of power supply agreements with local utilities." It bemoaned the fact that the federal utility's rate increase was not subject to independent regulatory rate reviews by an agency like a state public service commission.

"People across the Tennessee Valley will see electric bills increase because their public power utility has spent their hard-earned money on plans that it refuses to release to the public. But what is perhaps most disappointing is the fact that the people of the Tennessee Valley have never known anything different. They do not know that most utilities must present a detailed case for public scrutiny before raising rates. TVA has a visage of public power as a federally owned utility but operates as an unregulated private monopoly," SACE Research Director Maggie Shober said in a statement last week. ■

NYISO News

National Grid Lining up 70-plus Transmission Projects

Sweeping Update Sets Stage for Expansion of Renewables in New York

By John Cropley

Hundreds of projects are in the works across New York to make its grid better able to handle storms and the clean energy transition that state leaders are trying to implement.

Major new lines draw attention with their multibillion-dollar, multi-gigawatt proportions, but they are far outnumbered by their much-smaller cousins. All of the state's electric utilities are doing this work to some degree; the leader of National Grid's campaign spoke to *RTO Insider* about that utility's plans.

National Grid's *Upstate Upgrade* is a portfolio of more than 70 projects announced in March that will continue through 2030. Early components include 115-kV line updates, new and rebuilt substations and supporting work such as access road improvements.

None of these upgrades has the profile of the 340-mile, $6 billion HVDC line being built to import electricity from Canadian hydropower plants, but altogether, the Upstate Upgrade is expected to cost more than $4 billion. And National Grid plans billions of dollars in additional work beyond that.

New York's efforts to decarbonize are experiencing delays and cost escalations. But if anything close to the projected increases in electric generation and demand materialize, much more than the Upstate Upgrade is likely to be needed.

The state Public Service Commission has authorized upgrades costing billions and has set the stage for billions more in spending through planning processes that anticipate future needs rather than respond to present needs.

Bart Franey, National Grid's New York vice president of clean energy development, said the Upstate Upgrade consists of two phases, both informed by this need to anticipate future demand.

Phase 1 is refurbishment of older infrastructure that National Grid was going to do anyway for purposes of reliability and resilience but decided to proactively expand in expectation of needs created by the state's decarbonization policies and goals.

Phase 2 is purely proactive upgrades that might not have been contemplated were it not for the growing demand for clean electricity.

Pockets of renewable power generation are growing in rural areas of New York that are removed from population and industry centers, Franey added, something not anticipated when the grid was built decades ago.

"Not unlike other utilities, our grid is pretty old," he said. "Its original design was to serve those remote rural communities and industries. Now it's being asked to export way more power on the same circuit. That bidirectional nature always existed, but rather than serving a couple hundred megawatts, we're now demanding that it export 1,000 or more megawatts."

Upgrades are shown in progress at the National Grid substation in Gloversville, N.Y. | *National Grid*

Of interest to the host communities, the upgrades will harden the grid against severe weather. They also will create temporary economic benefits during construction and longer-term development opportunities when the work is completed.

Slow and Costly

A series of reports this summer shows the scope of the task facing New York as it tries to decarbonize and shows the impediments to progress that have been cropping up.

NYISO on July 23 issued its latest *System and Resource Outlook*. Highlighted in boldface was the assessment that "historic levels of investment in the transmission system are happening but more will be needed."

The outlook notes that New York's electricity consumption is expected to increase 50 to 90% over the next 20 years as heating and transportation are electrified; large industrial loads are added in the upstate region; and the installed generation capacity as much as triples.

Also in July, the two state entities in the forefront of the energy transition reported that New York is likely to miss its goal of 70% renewable energy by 2030, perhaps by a wide margin, due to delays and cost overruns.

The state comptroller reached the same conclusion in an audit that also faulted the same two entities for not telling New Yorkers how much the grand vision may cost.

Price tags for individual projects and initiatives are being announced as they are approved, but no estimate has been offered of the total cost of decarbonization in a state that has some of the highest taxes and utility rates in the nation.

It's also worth noting that upstate utilities have had a fairly static customer base. Census data shows that from 1970 to 2020, the population of the 11 southernmost counties (in and around New York City) grew 14.5%, but the 51 upstate counties grew only 4%,

And most of that growth was concentrated in a handful of places — take away the top four counties and the upstate population actually shrank 0.6% during a half century when the nation's population grew 63%.

NYISO News

Franey offers a financial equation sometimes used to justify the costs of transmission projects: Putting more load on the grid spreads the cost of operating the grid more widely, lowering the cost for the small ratepayers who do not increase their electric use.

And he rejects the criticism sometimes leveled at transmission projects, that utilities love them for their regulated rate of return. Nothing is guaranteed, Franey said, especially in an era of more frequent and more severe storms.

But the Upstate Upgrade is about more than moving electrons north to south, he said.

"I get it, it's cost, cost, cost. But I don't think anyone talks about the value as much as they ought to," Franey said. "The value that we're talking about with jobs, the value we're talking about with increased tax [revenues]. These communities have not seen this type of economic activity — where that generation is being sited and built, where that cheap power is coming in, where those crews are spending their money — in a hundred years.

"What is frustrating for me as a practitioner in this space is, no one is talking about value."

Beyond the value of the project itself is the value of more electricity becoming available: It facilitates economic development.

The biggest example is Micron's plan to build a *semiconductor manufacturing complex* near Syracuse at a cost of up to $125 billion.

National Grid is *seeking approval to construct* eight new 345-kV underground laterals from an expanded substation to service the site — one to each planned chip fab plant plus one redundant line to each to ensure reliability.

With NYISO projecting a need for installed generation capacity to expand from 40 GW today to 100-130 GW by the early 2040s, a steady demand for new transmission seems inevitable.

"No matter what we do," Franey said, "we could never overbuild, because there's just so much demand between a data-driven economy, between large spot loads, between electrification of transport, between electrification of heating, and the new power flow dynamic that's being set up by renewables being sited remotely from the grid. If we put capacity out there, it is going to get used."

As a lifelong upstate resident, Franey sees these developments as positive not only for the utility but for a region whose economy has stagnated or declined for generations.

So the clean energy transition is a potentially major change in more ways than one.

"You used to get requests [for] 2, 3 MW, and now it's like 2 to 3 MW is nothing. Now, it's just like, hey, can you give us 30?" Franey said. "And again, I don't think it's a bad thing. I think that's actually a good thing. I like to see economic growth. I like to see people using more electricity."

A Century Old

National Grid is the largest of the five investor-owned electric utilities operating in upstate New York, where its 5,600 employees serve 1.7 million customers under the legacy name Niagara Mohawk, the electric and gas utility National Grid acquired in 2002.

It operates 5,600 miles of transmission lines with 275 transmission substations and 47,000 miles of distribution lines with more than 500 distribution substations across a 25,000-square-mile service area, which is about half the state's total footprint.

Dial back a century, and the picture is not so impressive.

Thomas Edison switched on the state's first electric grid in 1882 in lower Manhattan, but 40 years later, dark areas still dotted New York. Dozens of utilities — 59 of which would merge in 1929 to form what is now National Grid — were still extending power lines to rural areas.

One of those was the Taylorville Line, which in 1925 electrified a glacier-carved area of forests, farms and small villages south of the Canadian border.

Some of that original infrastructure remains in service in 2024. Pieces have been replaced for safety or reliability reasons, but the rest is still doing what it has done for 99 years: moving electrons through a sparsely inhabited area from one population center or generation center to another.

The difference now is that these sparsely populated areas are prime real estate for the wind turbines and solar panels New York wants to bring online in large numbers.

The Taylorville Line's original structures would be replaced as a Phase 2 project to accommodate anticipated renewable generation construction.

"We always say age doesn't necessarily indicate that the assets need to be replaced," Franey said. "Having said that, they were built to a different spec, different construction standard, and so now, going in with newer construction standards, you're modernizing it. They're going to be hardier; they're going to be able to weather storms, severe events, much more. Back then it was all about, 'Let's electrify the rural areas.'"

The Upstate Upgrade is foundational in many ways, particularly Phase 2 — it is not the final step, but it is necessary groundwork for large-scale decarbonization.

For example, National Grid is beginning to think about virtual power plants but it would be a while before it could create them. For that, it would need more transmission capacity to power more chargers to encourage more people to buy electric vehicles to set the stage for a vehicle-to-grid scheme that would be large enough to be meaningful.

EV adoption so far has been tepid in large swaths of National Grid's upstate territory.

The best example is Lewis County, which includes the area known as Taylorville.

One state database shows just 79 plug-in hybrid and battery electric vehicles among the 16,560 passenger vehicles registered in the county of 26,582 residents; another shows a total of four public charging stations in its 1,274 square miles.

That is the fewest EVs of any of the state's 62 counties except nearby Hamilton County, a wilderness area with only 5,100 year-round residents. And even Hamilton County has significantly more EVs registered per capita than Lewis County.

But there are other non-wire solutions that make sense in the near term as National Grid begins the Upstate Upgrade.

Grid-enhancing technologies, for example, can delay the need for new wires while a better picture develops of what the future needs will be and while new technology potentially is developed to meet those needs.

"We are doing a couple of grid-enhancing technologies, dynamic line ratings," Franey said. "The value proposition there was, it's not a permanent solution, but it's a relatively inexpensive solution that gets us to a point where we would absolutely need to make that transition over to a more permanent solution."

He added: "This is all burgeoning technology. We're getting comfortable with it. We're integrating it into the control room operations. We haven't even gone through a full calendar year hitting all seasons yet, so we're still learning and adopting it, but we have more in the queue, more in the pipeline. It shows a lot of promise." ■

NYISO News

Large Consumers Miffed at NYISO Proposal to Shorten SCR Notice Period

By Vincent Gabrielle

NYISO last week proposed shortening the activation notice period for special-case resources from 21 hours to four, which caused consternation among program participants at the Installed Capacity Working Group's meeting.

SCRs are large consumers that act as demand response resources at the direction of NYISO itself. As part of its Engaging the Demand Side initiative, the ISO has proposed to increase the required duration of SCRs' load curtailment from four hours to six. That proposal has received broad support from stakeholders, with some caveats. (See *NYISO Proposes Changes to Special-case Resource Program*.)

Among those discussed at the Aug. 29 meeting was NYISO's proposal to not give SCRs the option of curtailing load for only four hours. Michael Ferrari, a market design specialist with NYISO, said to have both the four-hour and six-hour options would require an annual elections process in which resources would have to declare ahead of the capability year what class they were in.

Zach Smith, senior project manager for NYISO, said that adding the additional options would delay implementation and that it did not want to delay a reliability program with broad stakeholder support.

Aaron Breidenbaugh, senior director of regulatory and government affairs for CPower, commented that this was the first time he had heard NYISO say that it was not doing something for a reason other than operational difficulty.

"Previously we've heard that operations can't handle multiple durations in real time, and I suspect they'll have a harder time if they only have four hours," Breidenbaugh said.

NYISO staff acknowledged that this was the primary issue with having multiple durations.

Notice Period

The ISO wants to reduce the current notice period to help maximize the grid operator's flexibility and reduce the likelihood of false notifications, Ferrari said.

But this proposal left some stakeholders surprised and frustrated.

One stakeholder who represents Multiple Intervenors — a group of large industrial,

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commercial and institutional consumers — said that the proposal was a "dramatic change" to spring on the demand side.

NYISO had said in July it was considering shortening the notification period, though it did not say by how much.

"This whole project is supposed to be about NYISO engaging the demand-side participants in these programs," the stakeholder said. "While participants could perform with less than 21 hours' notice, they strongly desired some advanced-day notification, preferably prior to the end of the prior work day."

To adjust load or activate generation, work schedules needed to be shifted in the event of a call, they said. The manufacturers who participate in the program go to great lengths to reduce their load when called on.

"They will see this proposed change as the straw that breaks the camel's back and causes them to leave the program," they said. "If that's not a concern for NYISO, that's fine. But I think NYISO should be aware that this could have a dramatic impact on participation."

The stakeholder said that Multiple Intervenors would be happy to have more meetings with NYISO, but they would not perform survey work for the ISO to assess their members' sentiments.

"We're not going to do a survey and do the NYISO's work for it," they said. "If you want that information, hold a meeting. We'll participate."

Jay Goodman, another representative of Multiple Intervenors, asked whether NYISO could provide any historical data on events in which it has called on SCR program participants and did not get corresponding activations. A NYISO staff member said they don't believe such information is published.

"I do want to note," Goodman said, "it's frustrating in the context of a project that is supposed to be engaging with the demand side, where requests for information not only from the demand side but the MMU, is met with the response of 'No, we can't provide that information. We won't provide that information.'"

Goodman went on to ask why NYISO hadn't brought up the four-hour notice period with the demand side directly, during earlier meetings with Multiple Intervenors. Ferrari said that the four-hour notice period had not been decided on by NYISO internally yet.

"The city is shocked as well to this significant change to the program," said Couch White attorney Amanda De Vito Trinsey, speaking on behalf of New York City.

"This causes a lot of industrial issues, but even for non-industrial customers, this is still a very significant impact on their operations and their ability to respond in a four-hour period," she said. "I encourage NYISO to come back right away with something to review."

A representative of the New York State Energy Research and Development Authority said they were disappointed that NYISO wasn't presenting a more flexible program and didn't have more information available for reasonable stakeholder follow-up questions.

Another stakeholder compared the various revisions to the SCR programs to multiple ruptured bulkheads on the Titanic. No one issue was going to kill the program, but all of them together would drive participants out.

"The first hole was having revenue reduced by one-third because of capacity accreditation; wham bam, now we're up to four bulkheads," they said. "Like, how much more do you think you can do in the guise of catering to operational needs and desires and still have a viable program? I'd say you're past that point."

They went on to say that this felt like evidence that NYISO wanted to get rid of the SCR program entirely. If NYISO wants to save the program, it needs to tone down some of the changes, they said.

"Thank you for your comments," said Ferrari. "If you'll allow me to take liberties with your analogy, there are a lot more icebergs in the water. … The grid is changing; it's a much more dynamic system; and you know we haven't made changes to this program in a quarter-century." ■

NYISO News

NYISO Presents Final 2025 Project Budget Recommendation

Stakeholder Feedback Saves Some Projects

By Vincent Gabrielle

| © RTO Insider LLC

NYISO last week presented the Budget and Priorities Working Group with its final *recommended 2025 budget* for in-house initiatives, showing that it responded to stakeholder feedback by reincluding several projects that had been cut.

The ISO's initial recommendations last month cut several stakeholder favorites, including implementing storage as transmission and market purchase hub transactions. (See *NYISO Presents Initial 2025 Project Budget Recommendation*.)

"We took the feedback that we got from the initial recommendation, went back, and looked at the projects," said Kevin Pytel, senior manager of product and project management for NYISO. "We have modified some of our estimates when we further scrutinized those estimates, trying to bring them down as much as possible for the resourcing." This freed up some resources for other projects, he said.

Most of the projects that had been excised were reincluded by modifying their deliverables, which may change when they come fully online. Pytel explained that some of the changes were possible because NYISO produced new estimates of how many labor hours they would take.

"What you found in the past is that you've made conservative estimates, as in protecting yourselves: estimates of how much time projects would take and that they don't take as much time as you estimate?" said Mark Younger of Hudson Energy Economics.

"That's what the data suggests, Mark," said Pytel.

Based on the recommended projects, NYISO estimates the total budget for 2025 to be $42.73 million — up from 2024's $41.62 million — with $22.56 million for labor, $8.31 million for capital and $11.86 million for professional services.

In response to a stakeholder question, NYISO staff said the total cost is slightly higher than what it initially recommended, mostly because of a $500,000 increase in labor costs.

The Integrating Champlain Hudson Power Express project "could not fit into budget due to resource constraints," NYISO said. The project aims to develop an operating protocol between Hydro-Quebec and the CHPE line, including identifying tariff revisions, software enhancements and integrating the facility to the system reliability tools. This would not impact the expected deployment in 2026, the ISO said. The line is expected to go into service that year.

The proposed budget is expected to be presented to the Management Committee at the end of this month, with a committee vote a month later and a Board of Directors vote in November. ■

CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS

Move Spells Small but Significant Victory for ISO in Western Day-ahead Market Competition

By Robert Mullin

CAISO scored a geographically small but symbolically significant victory in its contest with SPP on Aug. 28 with the announcement that two Black Hills Energy subsidiaries serving parts of Montana, Wyoming and South Dakota will move from SPP's Western Energy Imbalance Service (WEIS) to the ISO's Western Energy Imbalance Market (WEIM).

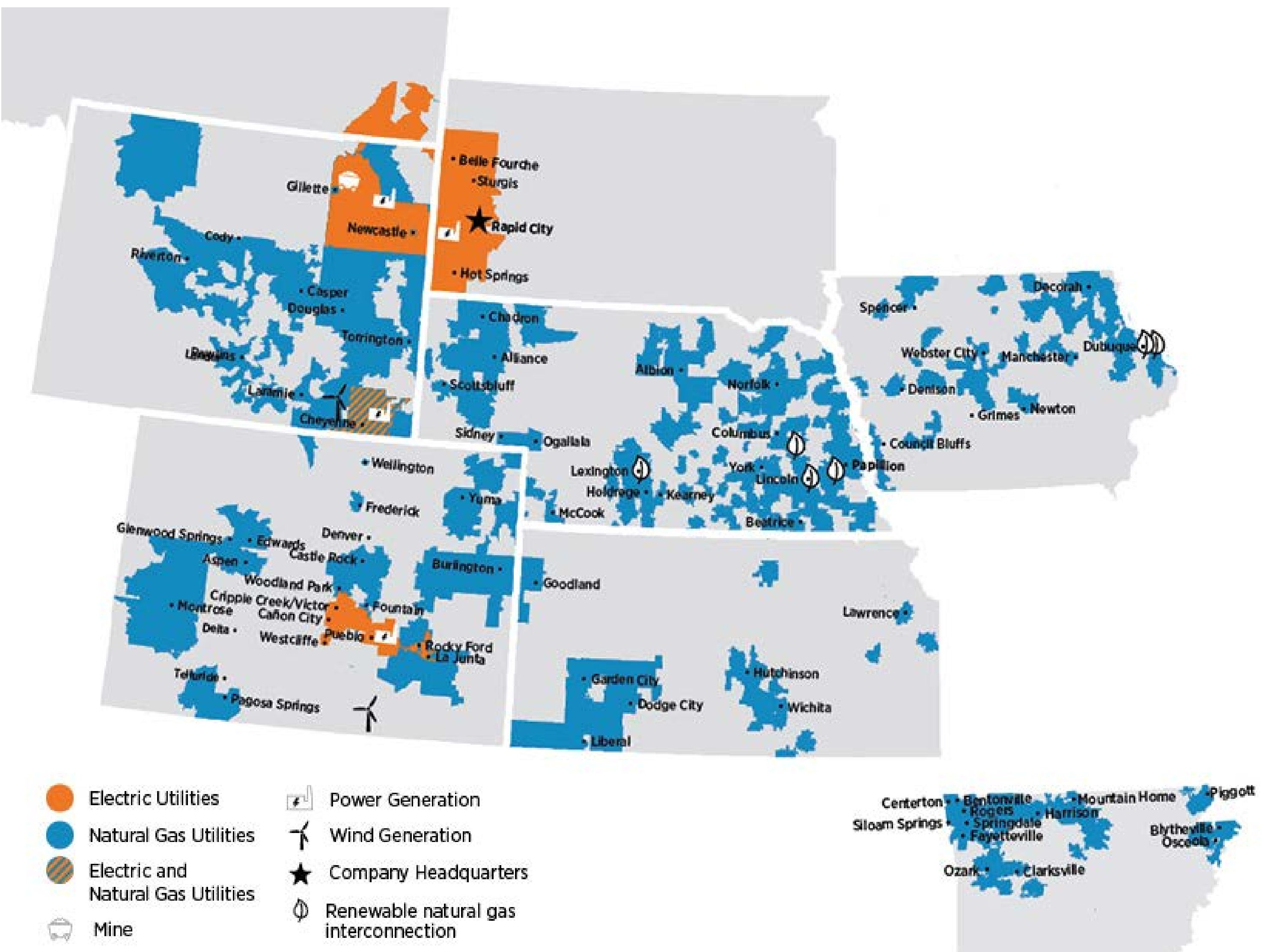
The decision by Black Hills Power and Cheyenne Light, Fuel and Power will expand the WEIM's presence in Montana and Wyoming and extend its footprint eastward to take in a slice of South Dakota, which would become the twelfth state included in the market.

"The agreement with California ISO provides the company with options to support reliability and system balancing, while paving the way for Black Hills Energy to participate in California ISO's Western Energy Imbalance Market, starting in 2026," Black Hills Energy said in an email to *RTO Insider*.

"We are very pleased to begin this process with Black Hills Energy to deliver future economic and reliability benefits to its customers," CAISO CEO Elliot Mainzer said in a statement.

But the decision might be most consequential as another development in the ongoing competition for participants between SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM), the latter of which builds on the WEIM.

In 2022, SPP said it would eventually phase out its real-time WEIS once its other Western market efforts gathered more momentum and members. (See *SPP to Phase Out WEIS as New Market Offerings Expand*.) At the time, SPP said it intended "to only provide one market offer-



The territories of the two Black Hills Energy utilities joining the Western Energy Imbalance Market are represented on this map by the orange areas in Montana, Wyoming and South Dakota. | *Black Hills Energy* ing in the West in order to provide maximum benefits for Western utilities" and that WEIS participants "will have the option to join the RTO or participate in Markets+."

That projected outcome seems to have played a role in Black Hills' decision to migrate to the WEIM.

"The planned formation of the SPP RTO West required us to assess our future market path, as it did not appear that the WEIS market status quo would remain an option after RTO West is operational," the utility told *RTO Insider*. "We have found imbalance market participation to be beneficial for our customers, and the opportunity for our utilities to participate in the WEIM allows us to continue to optimize our generation operations while maintaining our high reliability and creating long-term value for the customers we are privileged to serve."

Asked whether it is now considering joining the EDAM, Black Hills said it "will continue to monitor and be engaged in the development of markets in the Western Interconnection and will pursue future markets that provide additional value for the company and our customers."

After joining the WEIS in 2023, both Black Hills subsidiaries participated in the extensive "Phase 1" effort to develop the tariff for Markets+, which SPP filed with FERC in March — and for which it received a deficiency notice July 31. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.)

Black Hills offered an equivocal response to another question about whether it plans to continue funding Markets+ during the Phase 2 implementation process, reiterating that it will continue to "monitor and be engaged in" Western market developments.

An SPP *document* shows that Black Hills Power would be responsible for providing a 0.9% share of Phase 2 funding, while Cheyenne Light would be on the hook for 0.6%, amounts other funders would be required to cover if the two utilities withdraw from the effort. SPP estimates Phase 2 will cost about $150 million. (See *BPA to Delay Day-ahead Market Decision, Sources Say*.)

"SPP is aware of the announcement by Black Hills and continues to support each market participant's ability to decide on a market choice that they consider best for their customers," SPP spokesperson Meghan Sever said in an email. "The decision by Black Hills does not impact the viability of Markets+ or the RTO expansion in the West."

Another Western BA

According to an *integrated resource plan* the utilities jointly filed with the South Dakota Public Utilities Commission in 2021, Cheyenne Light and Black Hills Power together serve more than 117,000 customers and operate 1,344 miles of transmission, most of which are maintained by the latter utility. That system interconnects with PacifiCorp and the Western Area Power Administration's Rocky Mountain Region.

While both utilities sit within WAPA's balancing authority area, the WEIM implementation agreement signed between CAISO and Black Hills Energy on July 31 stipulates that one of the utilities will be required to register a new BA to facilitate participation in the market.

The utilities' 2021 IRP included a study by NAES that found they "are well situated to become a BA" but noted that maintaining it would cost between $5.77 million and $10.21 million annually, compared with costs of $3.54 million to $5.28 million a year for remaining in WAPA. Moving into PacifiCorp's neighboring BA would cost the two utilities $3.10 million to $3.21 million annually, the study found.

"The implementation agreement supports our South Dakota and Wyoming electric utilities as they prepare to transition from the Western Area Power Authority, which currently provides balancing authority services, to a new BA in 2026," Black Hills told *RTO Insider*.

That move would bring the number of Western BAs to 39.

The Black Hills announcement comes two days after the Bonneville Power Administration said it will delay its choice of a Western day-ahead market until next year. (See *BPA Postpones Day-ahead Market Decision Until 2025*.) ■

Company Briefs

Exxon to Sell Non-core Oil Assets in Permian Basin

Oil giant Exxon Mobil last week said it is looking to sell oil assets in the Permian Basin that could fetch $1 billion.

The company wants to sell a collection of conventional oil and gas properties in the Permian across west Texas and New Mexico to focus on higher-growth assets.

More: *Reuters*

Microsoft Signs 20-Year Solar PPA with EDP Renewables in Singapore

Renewable energy producer EDP Renewables (EDPR) last week announced a 20-year agreement with Microsoft through which the tech giant will purchase 100% of the renewable energy via EDPR's SolarNova 8, the largest solar project in Singapore.

EDPR announced earlier this year that it had been awarded Phase 8 of the SolarNova program, to install up to 200 MW of capacity across 1,075 Singapore public housing buildings and 101 government-owned buildings.

It is the second agreement between the companies in Singapore.

More: *ESGtoday*

Ice Industries to Invest in Production Facility to Supply First Solar

Ice Industries last week announced it will invest $6 million to build in the Lacassine Industrial Park, La., that will focus on roll forming steel back rails for solar panels for First Solar.

First Solar is expected to begin operations in the second half of 2025.

More: *The Acadiana Advocate*

Federal Briefs

Researchers: Clean Energy Transition Will Cost $1T in Federal Spending

For the U.S. to meet its clean energy goals, the federal government would need to invest around $1 trillion into local economies by 2031 via tax incentives, according to a new report from RMI.

So far, through June 2024, the government has distributed $66 billion — or around 6% of the full spending that climate commitments demand.

The RMI report looked specifically at how well each state has captured federal tax incentives, compared to estimates of their full funding potential. On average, states have received 7% of the total funding they would need to reach their full potential by 2031.

More: *Grist*

USDA Invests $140 Million to Lower Energy Costs in Kentucky, Nevada

The U.S. Department of Agriculture last week announced $140 million for clean energy projects in Nevada and Kentucky to lower bills for households, expand reliable access to clean energy and create jobs for families, small businesses and agricultural producers.

The Valley Electric Association in Nevada plans to use an $80.3 million investment to install a 37-MW solar and storage system to serve Pahrump and the Fish Lake Valley region. In Kentucky, some of the money will go toward building three hydro plants on the Kentucky River.

More: *USDA*

Former Union Director Indicted on Warrior Met Coal Gas Pipeline Damage

The United States District Court for the Northern District of Alabama Western Division last week indicted James Gale Kerns in relation to Warrior Met Coal gas pipeline damage caused in 2022.

Kerns has been indicted on one count of destruction of property with an explosive device after allegedly destroying parts of a facility on or around March 23, 2022.

In April 2021, approximately 900 members of the UMWA began striking against the Warrior Met Coal Mine after failed contract negotiations and an expired labor contract.

More: *WBMA*

National/Federal news from our other channels

NERC Examines Transfer Capability in Draft ITCS Installment — ERO Insider

FERC Report Identifies CIP Audit Lessons Learned — ERO Insider

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State Briefs

IOWA

County Approves Resolution Objecting to Eminent Domain for CO2 Pipeline

Hancock County last week became the state's 14th county to approve a resolution objecting to the Utilities Commission's authority to enact eminent domain for privately owned and operated CO2 pipelines.

The county board's action comes less than a week after the South Dakota Supreme Court handed down a unanimous decision that included the finding Summit Carbon Solutions did not prove its common carrier status, which prevents Summit from using eminent domain in that state for its proposed pipeline. The pipeline will also cross Hancock County.

More: *Globe Gazette*

Utilities Commission Issues Pipeline Permit for Summit Carbon Solutions

The Iowa Utilities Commission last week issued a construction permit for Summit Carbon Solutions' proposed liquid pipeline.

The commission issued the permit without modifying the previously imposed conditions Summit Carbon must meet to begin construction — the most significant of which is that the project must be approved by regulators in North Dakota and South Dakota. The commission also required the company to secure and maintain a $100 million insurance policy and agree to compensate landowners for any damages that result from the pipeline's construction.

The company hopes to begin construction next year.

More: *Iowa Capital Dispatch*

KENTUCKY

Beshear Makes Appointments to Energy Planning Commission

Gov. **Andy Beshear** last week filled several seats on the new Energy Planning and Inventory Commission created to slow the retirement of power plants fueled by coal and natural gas.

Among Beshear's first eight appointees to the 18-member board were Louisville Gas and Electric and Kentucky Utilities CEO and President John Crockett and Duke Energy Senior Vice President Brian Weisker. The law requires one of the governor's appointees represent an investor-owned utility.

Under the new law, most of EPIC's decision-making power will be vested in a five-person executive committee. The law also requires EPIC to submit a study of the state's electricity supply and the impact of federal policies on it by Dec. 1.

More: *Kentucky Lantern*

MASSACHUSETTS

Holtec Appeals DEP's Denial to Discharge Pilgrim Wastewater into Bay

Holtec Decommissioning International last week announced it is appealing a Department of Environmental Protection ruling denying the company permission to release treated wastewater from the Pilgrim Nuclear Power Station into Cape Cod Bay.

Holtec wants to discharge up to 1.1 million gallons of industrial wastewater — treated beforehand, but still containing some radionuclides — from the shuttered plant. However, the DEP has identified the bay as "a protected ocean sanctuary" as defined under the state's Ocean Sanctuaries Act.

Holtec filed its appeal Aug. 16 with the Office of Appeals and Dispute Resolution and argues the NRC has the sole responsibility of deciding on discharge of "radiological liquid effluent" under the Atomic Energy Act.

More: *Cape Cod Times*

MISSOURI

Evergy Seeks Rate Increase

Evergy last week applied to the Public Service Commission for a 13.99% increase in electric rates, giving the company up to $104.5 million more in revenue a year.

Evergy said the higher rates are needed to recoup money it spent on two natural-gas plants and for upgrades to withstand severe weather.

The commission figures to decide in December.

More: *Missouri Independent*

NEVADA

BLM Approves Solar, Battery Storage Project

The Bureau of Land Management last week issued a right-of-way for the Dry Lake East Energy Center Solar Project in Clark County, Nev.

The battery energy storage system will generate 200 MW of solar energy with 600 MW of storage.

More: *Power Technology*

NEW YORK

Republicans Outline Legislation to Delay Renewable Transition

Senate Republicans last week unveiled a legislative package to delay the state's statutory mandates to transition to renewable energy.

The legislation would push back deadlines in the state's climate law, which passed in 2019 and requires a 40% reduction in greenhouse gas emissions by 2030, by 10 years and require a study of its costs.

Other parts of the package would prevent the state from closing any power plants before new facilities come online and require it to invest in "alternative energy" options.

More: *WSKG*

OHIO

PUC Proposes $1.45M Fine Against Duke for Billing Errors

The Public Utilities Commission last week proposed a $1.45 million fine against Duke Energy for repeatedly violating state administrative code while making more than 100,000 billing mistakes since 2022.

The fine is part of a revised settlement proposal, filed by PUC staff Aug. 12, to address ongoing problems with Duke's "Customer Connect" software system. The revised settlement would triple an earlier penalty.

By April 2023, one year after installation, PUC staff said Duke had reported 106,453 billing errors.

More: *WCPO*

PENNSYLVANIA

PECO Looking for Rate Increase in Philadelphia Area

PECO recently filed for a 12.3% rate increase with the Public Utility Commission.

The increase would add $16.67 a month more to the typical residential customer bill starting in January. That would be followed by an additional increase of $2.07 per month in 2026.

PECO argues it's investing billions in infrastructure upgrades and needs the earnings increase to ensure its continued financial health. Without a higher revenue stream, it'll lose opportunities to attract capital investments.

More: *BillyPenn*

VIRGINIA

Charlotte County Approves Permits for Dominion Solar Project

The Charlotte County board last week unanimously approved a permit and a siting agreement for Dominion Energy's Quarter Horse Solar project.

Dominion has shaved down the project since purchasing it from Apex Clean Energy Holdings. The 125-MW project will sit on 1,678 acres and consist of 291,384 solar panels.

More: *The Charlotte Gazette*

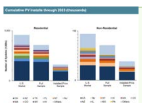
NRC Grants North Anna Extensions

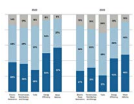
The NRC approved 20-year extensions for North Anna Power Station's two nuclear reactors, allowing them to operate through 2058 and 2060, Dominion Energy announced last week.

The two reactors were originally licensed to operate for 40 years beginning in 1978 and 1980. In 2003, the licenses were renewed for an additional 20 years, permitting them to operate through 2038 and 2040.

More: *Virginia Business*

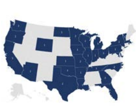
National/Federal news from our other channels


Berkeley Lab Report Highlights Trends in Distributed Solar — NetZero Insider


DOE Details Strong Job Growth in Clean Energy — NetZero Insider


Report Quantifies Consumer Savings from Biden-era Efficiency Standards — NetZero Insider


DOE Awards $240M for City, State Building Performance Standards — NetZero Insider


New IIJA Funding Seeks to Close Gaps in EV Charging Networks — NetZero Insider

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AEU Presses Call for Streamlined State Permitting — NetZero Insider

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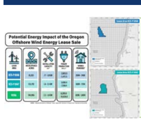
BOEM Sets Oct. 15 Oregon Wind Lease Auction — NetZero Insider


BLM Issues Solar Roadmap for 11 Western States — NetZero Insider


Truckers Group Opposes Wash. Clean Trucks Timeline — NetZero Insider

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