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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

FERC Watchers Weigh in as Transmission Rule Approaches Finish Line (p.3)

Groups Urge Inclusion of Cost Containment in FERC Tx Planning Rule (p.5)

CAISO/West

NW Freeze Response Shows WEIM Value, CAISO Report Says (p.7)

Powerex Report Expands NW Cold Snap Debate (p.9)

CAISO/West

FERC Approves Most of CAISO's Rule Changes for EDAM Participation (p.12)

WAPA DSW Cites Lack of Benefits in Markets+ Withdrawal (p.13)

RTO, Day-ahead Choice Closely Linked, Nev. Effort Shows (p.15)

Colorado PUC Sets Rules for Market Participation (p.16)

ISO-NE MISO

National Grid Backs out of Twin States Clean Energy Link Project (p.21)

Conservation Groups File Another Lawsuit to Stop Cardinal-Hickory Creek's Last Mile (p.31)

GCPA MISO-SPP Forum

FERC's Christie Warns of 'Very Dark Place' (p.25)

Overheard at 10th Annual GCPA MISO-SPP Forum (p.26)

COVER: Construction of the Huntley-Wilmarth transmission line project in Minnesota | *Michels Corporation*

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In this week's issue

FERC/Federal News

FERC Watchers Weigh in as Transmission Rule Approaches

By James Downing

All indications are that FERC is working to complete its transmission planning and cost allocation rulemaking in the next few months, with public statements from commissioners saying it's a priority and those familiar with the agency placing bets during which month's open meeting a final rule will be announced (*RM21-17*).

With three nominees awaiting confirmation for the two open seats and that of Commissioner Allison Clements, whose term expires in June, sources said in recent interviews it might be best for FERC to act on the Notice of Proposed Rulemaking before its composition changes. (See *Phillips: FERC to Issue Transmission Rule in 'Very Near Future'*.)

"I think Commissioner Clements very much wants to be part of this," former FERC Chair Jon Wellinghoff said. "So, I'm sure she's doing everything she can to work with staff and work with the other two commissioners, to move this forward as quickly as possible."

The rulemaking could face a delay if it is not completed before the composition of the commission changes, said WIRES Executive Director Larry Gasteiger, a former FERC staffer.

"This is an extremely complicated rulemaking effort that the commission is doing," Gasteiger said. "And just for [the new members] to get up to speed on it, in order to knowledgeably vote on it, is inevitably going to take a couple of months minimum. That will be added time on the timeline for getting the rule out."

Another issue is uncertainty around November's elections, with the House, Senate and White House up for grabs.

Republicans could use the *Congressional Review Act* (CRA) to overturn a rule that is filed late in the Biden administration, said former FERC Chair Neil Chatterjee, now a senior adviser at law firm Hogan Lovells. Rejecting a rule requires votes of disapproval by both the House and Senate but can be blocked by the president unless his veto is overridden.

"I don't know if it's constituted as a major rule, but I think the White House and FERC don't want to take that risk," Chatterjee said. "And I think that, certainly, there are steps the commission could take, if you had Republican majority control, that would try to change course on some of these rulemakings."

Construction of the Huntley-Wilmarth transmission line project in Minnesota | *Michels Corporation*

The commission currently has two Democrats, Clements and Chair Willie Phillips, and one Republican, Mark Christie. The three candidates nominated by President Biden last month would give Democrats a 3-2 edge. But if Donald Trump retakes the White House, he could replace Phillips, whose term expires in 2026, with a Republican. (See *Biden Names 3 Nominees to Give FERC 5 Members Again*.)

Negotiations on the 11th Floor

FERC observers expect the three commissioners' offices are exchanging ideas on what should be in the final rule — and that can take some time. (See related story, *Groups Urge Inclusion of Cost Containment in FERC Tx Planning Rule*.)

Christina Hayes, executive director of Americans for a Clean Energy Grid, was a FERC staffer in 2011, the last time it made major changes to its transmission planning and cost allocation rules with Order 1000.

"There was something like 40 hours where the commissioners' advisers were talking and negotiating, before they were able to issue Order 1000," Hayes said. "That's something like two months of negotiation among commissioners' offices on the 11th floor. So, I imagine they're probably well into that process at this point."

The transmission rule came out of an *advanced NOPR* issued nearly three years ago, so the commissioners have been talking about the issues for some time, said Philip Moeller, executive vice president of regulatory affairs for the Edison Electric Institute.

"Each commissioner is going to have their own set of priorities," said Moeller, who was on FERC when it passed Order 1000. "And those are probably going to be negotiated and probably have been negotiated to some extent for at least the last couple of years."

To the extent that commissioners support the rule's overall thrust — that the grid needs to expand to meet future needs —they will be working on compromises because the more consensus there is, the more robust the rule will be in the face of inevitable litigation, Moeller added.

Impact of Dissents

In 2011, Moeller dissented on Order 745 over its compensation method for demand response (DR). Litigation over the rule wound up at the Supreme Court, which ruled against appeals that claimed FERC had overstepped its jurisdiction. (See *Supreme Court Upholds FERC Jurisdiction over DR*.)

FERC/Federal News

"It was kind of fun to have my dissent mentioned there during arguments," Moeller said. "But I think ultimately the problem with that litigation, specific to 745, was that the main attack was on the jurisdiction. And that was really never an issue for me. For me, it was the level of compensation and how it was done. And unfortunately, the court focused solely on the jurisdiction and ruled that FERC had it."

The more complex issue of compensation — Moeller would have preferred a somewhat smaller payment for DR in energy markets — was largely ignored by the courts because litigants focused on jurisdictional questions over how DR is treated in state-regulated retail markets and federally regulated wholesale markets.

Wellinghoff was the driving force behind Order 745 as chair of FERC at the time. While he did not convince Moeller, he did get a Republican vote from then-Commissioner Marc Spitzer.

"To the extent those dissents are well written, and those dissents have legitimate reasons for objecting to portions of the order, they act as fodder for the appellant," Wellinghoff said. "Those are things that they use as arguments in court, so they can be compelling in that way."

While partial dissents like Moeller's on Order 745 are less of a threat to a rulemaking than a full dissent, Wellinghoff said judges will rule based on the legal arguments before them rather than counting votes of the commissioners.

Cost Allocation

Ultimately, the public will see the outcome of all the behind-the-scenes debates when FERC publishes a final rule. When asked what that should look like, Grid Strategies President Rob Gramlich (another former FERC staffer) pointed to a letter Senate Majority Leader Chuck Schumer (D-N.Y.) *wrote* to the commission last summer. Schumer said the commission should prescribe the benefits that transmission planners must consider to ensure cost-effective transmission is built and costs are properly allocated.

"Figuring out how they sort out cost allocation will be important — just to make sure that they stick to the beneficiary-pays approach, which is what the courts have said they need to do, and they don't end up sticking too much of the costs on any one party or group," Gramlich said. "And then making sure there's a process to resolve disagreements."

FERC likely will give states chances to come to an agreement on cost allocation before the commission considers stepping in, Gramlich said.

Asked about Clements' thoughts on the NOPR, her office provided *RTO Insider* her response to Schumer. She said the commission aimed to develop a "comprehensive and durable approach" that leads to building the kind of infrastructure that has been underdeveloped in recent years.

"I agree that cost allocation rules should endeavor to involve states, while at the same time creating incentives for collaboration and against free ridership," Clements wrote.

Christie has long argued against states paying for the policies of others. In a recent dissent, he argued that states generally should be held above other "stakeholders," saying most of them are "rent-seeking special interests." (See *FERC Rejects Complaints from IMM, W. Va. PSC Arguing for Access to PJM Liaison Committee*.)

Figuring out how to balance competing policies — with some states seeking rapid progress toward net-zero emissions by midcentury and others wanting nothing to do with it — is a key issue commissioners are wrestling with, Moeller said.

"If you see what New Jersey is doing with their offshore wind [transmission], they're willing to pay for it themselves," Moeller said. "So, it's certainly doable under the status quo."

Chatterjee said the commission is likely to encourage states to take the lead in determining how public policy project costs are regionally allocated. "The fight will be over what is the dispute resolution mechanism," he said.

That is where Christie might wind up issuing at least a partial dissent if Chair Phillips can't bridge any divides among the three members, he added. It will be hard to get states like Chatterjee's home of Kentucky that have little interest in the energy transition to agree on a transmission plan with states that actively support the transition, he said.

"I think for a state like Kentucky, the view would be we didn't ask for these benefits, so we shouldn't have to pay for them," Chatterjee said. "And just because FERC is defining these benefits, that doesn't mean that our ratepayers should bear the costs."

Will a Federal ROFR be Reinstated?

Another point of contention as the transmission rule nears the finish line is what to do about competition. Both Moeller at EEI and Gasteiger at WIRES would like to see the federal right of first refusal (ROFR) at least partly reinstated; it's one of EEI's priorities.

WIRES recently released a *report* based on examples of 29 major projects around the country, arguing that collaboration is key to building out the transmission grid. The competition pushed by Order 1000 has served to discourage that collaboration, WIRES contends.

"If you're competing against your neighbor for the ability or the right to build a project, it doesn't create the same incentives to share information or to work with them on trying to get a project built," Gasteiger said.

Wellinghoff, a champion of transmission competition in Order 1000, argued that pulling back on it now would reward bad behavior by incumbents.

Order 1000 required transmission providers to remove from their FERC tariffs ROFRs on projects selected in a regional transmission plan for cost allocation. It did not affect the right of incumbent transmission providers to upgrade their local facilities.

"There just needs to be, perhaps, more oversight," Wellinghoff said. "There needs to be more consideration that perhaps even these smaller lines need to be competitive. I'm not sure that the exemption that we put in the original Order 1000 is appropriate. I believe that these lines can be bid competitively and developed and constructed competitively and we would come out better for it." ■

National/Federal news from our other channels

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FERC/Federal News

Groups Urge Inclusion of Cost Containment in FERC Tx Planning Rule

By John Norris

A coalition of transmission, utility and consumer advocates on March 6 recommended that FERC incorporate cost management protocols into its final rule on transmission planning and cost allocation (RM21-17).

The group — which includes the Electricity Consumers Resource Council (ELCON), the Large Public Power Council (LPPC), Americans for a Clean Energy Grid (ACEG), the Clean Energy Buyers Association (CEBA) and the National Association of State Utility Consumer Advocates — hosted a webinar to endorse a proposal requiring that transmission providers incorporate cost-benefit reporting mechanisms throughout their projects' lifecycles.

It urged FERC to mandate that providers periodically file cost allocation reports tracking anticipated project costs against initial projections. Under the proposal, if a provider's publicly filed report reveals that a project's costs have either exceeded a predefined threshold percentage of its original projected cost or fallen below an approved benefit-cost ratio, a process administered by an RTO or ISO would be initiated to reconsider the project's cost allocation to prevent consumers from bearing undue financial burdens.


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"Instilling greater transparency and cost discipline in transmission development protects consumers from undue costs and provides assurances that consumers will benefit throughout the life of the project," ELCON CEO Karen Onaran said in a press release.

John Di Stasio, president of LPPC, said the proposed provisions would ensure that transmission projects approved through the regional planning processes undergo "a cost-benefit analysis not just at the outset, but [also] throughout the life of construction, because at the end of the day, consumers are the ones who bear the cost of new infrastructure, and we want to make sure there is oversight on their behalf."

The group proposes that FERC's final rule establish a reconsideration threshold at 25% or more above the projected cost allocation. This reconsideration process would allow project sponsors to justify their cost deviations and present mitigation plans until construction.

"This rule would require planners to take a long-term look at the changing circumstances and plan for all economic or reliability benefits and adopt some sort of backstop or dispute resolution for cost allocation," said Christina Hayes, executive director for ACEG.

"We're no longer just talking about an energy transition, but we're talking about a grid expansion," said Bryn Baker, senior director of CEBA. "And this grid expansion means that we cannot just be talking about adding new generation, but we have to talk about moving the cheapest available electrons to where they're needed."

The commission *issued* a Notice of Proposed Rulemaking last year to change how transmission planning and cost allocation processes are conducted to help build out the grid in the long term. The docket has received a barrage of comments, reports and appeals from industry groups, politicians and transmission stakeholders urging that FERC's final rule should allow for regional flexibility; not hinder ongoing innovation; consider factors related to competition, consumers and transparency; and be issued by year-end, among other recommendations. (See *FERC Gets Dueling Competition Studies in Transmission NOPR Docket*.)

"Striking a balance between advancing clean energy goals and protecting consumers from unforeseen costs is essential as FERC considers large-scale regional transmission planning," Di Stasio said.

During the webinar, a reporter asked how the group arrived at the 25% reconsideration threshold and if it could unreasonably slow down project approvals.

Di Stasio replied that the group has discussed with FERC how "these protocols could create a barrier" but added that "if it's clear at the outset and there's ongoing monitoring and recording, it still gives an opportunity for projects to continue" and "[the threshold] shouldn't necessarily slow anything down and, in fact, gives us greater confidence in whatever gets approved."

Hayes added that "this proposal makes sure that we're very clear-eyed about the costs and benefits as we go through planning and makes sure that, should things go awry, there's a check in that process."

The 25% figure is "not necessarily a line drawn hard in the sand," Baker concluded. "But the point of the entire exercise is to say if costs have increased that much, let's just have a quick check." ■

FERC/Federal News

NREL Looks at Zonal Approach to Renewable Energy

Analysis Cites Benefits of New Interregional Transmission

By John Cropley

A new analysis concludes that building long-distance high-voltage transmission would save money and speed decarbonization of the U.S. power grid.

The *National Renewable Energy Laboratory report* on interregional renewable energy zones (IREZ) issued March 7 is the first of several companion reports for the National Transmission Planning Study, targeted for release later this year.

The IREZ concept would link the highest concentrations of the lowest-cost renewable energy potential with the highest concentrations of need for that power by building new transmission lines stretching hundreds of miles.

The value of interregional transmission has been well established as the nation shifts to a more intermittent power generation profile. The challenges of building it also are well known.

For starters, state-level review of transmission proposals often focuses heavily on needs and benefits within that state, rather than the region or nation. Then there are multiple federal permits, local authorizations and other state approvals to secure, plus willing cooperation of states with each other and in some cases, the approval of tribal nations.

FERC flagged these and other barriers to siting long-distance high-voltage transmission — as well as opportunities — in a 2020 *report to Congress*. The Brattle Group *offered its take* in 2021.

In *announcing* the new report, NREL acknowledged the importance of multistate cooperation to make the IREZ concept work.

Lead author David Hurlbut, an NREL researcher, said the IREZ report is intended to make it easier for states to answer the questions that arise in their regulatory processes.

"Long-distance transmission between planning regions was always harder to get through the approval process than new lines within the same region," he said. "But over the past few years, the power sector has been changing in ways that might make interregional transmission a more compelling option than it used to be."

The report could also inform tribal nations that will be part of the decision-making process when their lands are included in IREZs.

The report's authors wrote that the renewable energy zone concept originated in Texas two decades ago as wind power expanded in that state. Lessons learned from Texas' experience helped guide the process, which yielded several high-value IREZ corridors.

The authors say these corridors could help reduce carbon emissions, improve resource adequacy and boost grid resilience with a relatively small impact on customers' bills.

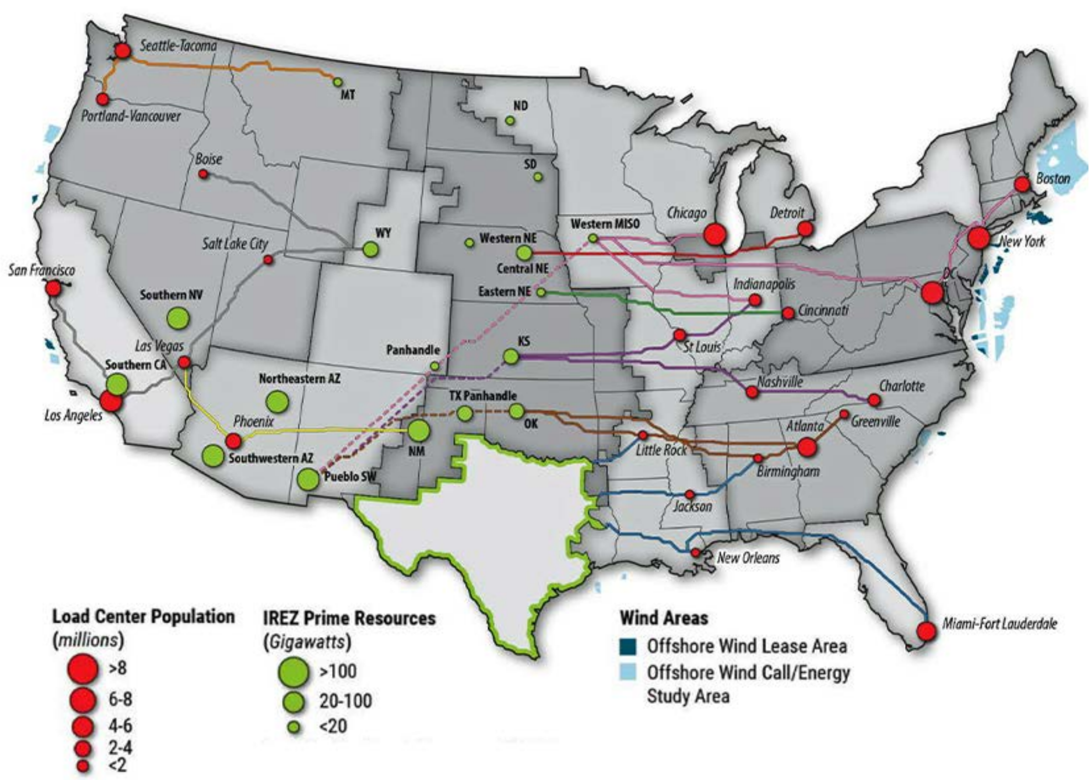
They are, the authors say, the "low-hanging fruit" in the clean energy transition, maximizing the value of commercially mature wind and solar technology and delivering that value to the customers who would pay for it.

The wind IREZ regions cited in the report are almost all in the Midwest and the solar IREZ regions are all in the Southwest, while the load centers are mostly hundreds or many hundreds of miles distant.

Subsequent analyses by states in a proposed corridor might lead to other configurations, but for the report, NREL analyzed the role of a 600-kV HVDC line with 3 GW of capacity in the resource mix. The authors also assumed that the best 15 GW of resource potential within the zone would compete for access to that 3-GW transmission hub.

Several of the IREZ corridors analyzed in the report align with those in the U.S. Department of Energy's *National Transmission Needs Study*, issued last October, and the upcoming *National Transmission Planning Study*, as well as with projects under construction or in advanced permitting.

The Pacific Northwest National Laboratory contributed economic analysis to the IREZ report. It also is collaborating with NREL on the National Transmission Planning Study. ■



The National Renewable Energy Laboratory created this interregional renewable energy zone map to show how new interregional transmission could move renewable energy resources from greatest area of concentration to greatest concentration of potential users. | *NREL*

CAISO/West News

NW Freeze Response Shows WEIM Value, CAISO Report Says

Report Latest Volley in Skirmish over ISO's EDAM and SPP's Markets+

By Robert Mullin


BPA transmission lines on the Washington side of the Columbia River near The Dalles Dam. | *© RTO Insider LLC*

CAISO's Western Energy Imbalance Market (WEIM) played a crucial role in managing energy flows around the West to help support Northwest utilities during an extreme cold snap in January, according to a new report from the ISO describing its response to the winter weather storm.

The 80-page *report* released March 6 represents the latest volley in an ongoing skirmish among Western electricity sector stakeholders over exactly what occurred on the regional grid during the Jan. 12-16 deep freeze.

"The cold-weather event again demonstrated the benefits of the Western Energy Imbalance Market, an interstate electricity market that covers much of the West," CAISO said in the report. "The market's diversity of weather and generating resources allows Western regions to aid each other during winter and summer peak demand periods."

The event plunged the Northwest into near-record cold and triggered five energy emergency alerts (EEAs), including one critical EEA 3, which requires a utility to prepare for rolling blackouts to protect its system.

It has provoked a debate in the Northwest over how vital CAISO and its WEIM were in supporting the region during the storm, or if other factors were more important. The dispute has become a stand-in for the contest between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ and the related disagreement over whether the Bonneville Power Administration and other Northwest entities should join a single Western electricity market based on EDAM or continue to help SPP develop its alternative. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

Analyses from the Western Power Pool, the Public Power Council (PPC) — which represents the Northwest's publicly owned utilities — and others have downplayed CAISO's role. They've pointed to interchange data showing that most of the generation that rescued the Northwest originated in the Rockies and Southwest regions — and not California. That was evidenced by the fact that CAISO itself was a net importer of energy during the five-day weather event. (See *WPP: Cold Snap Showed 'Tipping Point' for Northwest Reliability*.)

CAISO's report hits back at that assertion — and other complaints about the ISO's response — by explaining the mechanisms that directed the movement of electricity across the WEIM over the course of the cold snap.

The report says the WEIM "economically rebalanced supply across the West to meet increasing demand as real-time conditions evolved over the Martin Luther King Jr. Day weekend."

"The market identified least-cost solutions within the wider WEIM footprint, transferring lower-cost electricity from the Southwest into California," it says. "These transfers allowed exports scheduled in the day-ahead and hour-ahead markets to flow to the Northwest, replacing more expensive generation while managing congestion on key transmission lines."

CAISO notes that its hourly exports in the day-ahead and real-time markets "increased significantly" during the event, exceeding 6,000 MW.

"CAISO became a net exporter over the Martin Luther King Jr. Day weekend for all hours of the day, excluding WEIM transfers," the report says.

The ISO said WEIM transfers into the CAISO area were not the result of limited supply within CAISO but rather a function of the "economic displacement and opportunities optimized by the market and bounded by the transmission and transfers availability in the wider footprint."

Congestion Response

Several factors were at play during the freeze, which the report notes. They included derates on the Pacific AC (PACI) and DC (PDCI) interties, generation outages and a fault in a fiber optic cable that caused Washington's Jackson Prairie natural gas storage facility to briefly halt sendout Jan. 13, prompting pipeline operator Williams to declare a force majeure that cut deliveries to interruptible customers, including some power generators.

The ISO notes that day-ahead prices surged in the Northwest bilateral market, with Mid-Columbia peak prices hitting $934/MWh on Jan. 13 while off-peak spiked to $927/MWh. While prices rose at the West's other major trading hubs (NP-15 and SP-15 in California and Palo Verde in Arizona), they never exceeded $250/MWh. The power price spikes in the Northwest in part resulted from the region's high spot natural gas prices, but gas prices also were elevated in California.

As Fred Heutte, a senior policy associate with the Northwest Energy Coalition, explained in a recent interview with *RTO Insider*, the price differentials created a situation in which Northwest load-serving entities looked south

CAISO/West News

for cheaper supply. The CAISO report shows the WEIM did the same.

"First, the WEIM market relied on the most economic supply available which was located in the Southwest; in turn, these import transfers displaced generation in California, which has been priced more expensively given higher gas prices," the CAISO report said. "Second, there were transmission limitations to afford additional exports or WEIM exports transfers to the Pacific Northwest because Malin [PACI] capacity was already fully scheduled, and no exports could flow on NOB [PDCI]."

During some intervals, northbound segments of Path 15 in California also experienced congestion, limiting flows into Northern California and the Northwest.

The CAISO report additionally addresses a complaint by the PPC that congestion revenue rights (CRR) holders in the ISO's market financially benefited from $125 million in congestion rents collected on interties into the Northwest during the freeze, while owners and capacity rights holders on the northern portions of those lines earned nothing.

"Before January, participants bought more than 900 MW of CRRs in anticipation of potential northbound congestion on California's northern boundary," the ISO's report says. "None of these rights were held by external load-serving entities, such as Northwest utilities, although they could have obtained the CRRs through the CAISO's CRR auction or the allocation process that provides CRRs for free to qualifying load-serving entities."

The report additionally notes that CAISO is the only Western balancing authority in the West "that manages transmission congestion through electricity prices at specific locations in its day-ahead market."

"Congestion in the Northwest can still result in higher prices, but those costs are not as visible to market participants as they are in the CAISO market," the ISO said.

In the report, the ISO points out that EDAM "provides additional mechanisms for managing congestion on either side of balancing area borders for participating entities and provides transparency on the distribution of congestion revenues collected through nodal pricing. The EDAM will be able to help Pacific Northwest transmission operators better manage and allocate the costs of congestion on their systems."

CAISO said it will discuss the report's findings during a March 11 public meeting.

RTO Insider will provide additional coverage of the report after having more time to delve into its analysis. ■

CAISO/West News

Powerex Report Expands NW Cold Snap Debate

Analysis Aligns with Northwest Stakeholders Critical of CAISO Response

By Robert Mullin

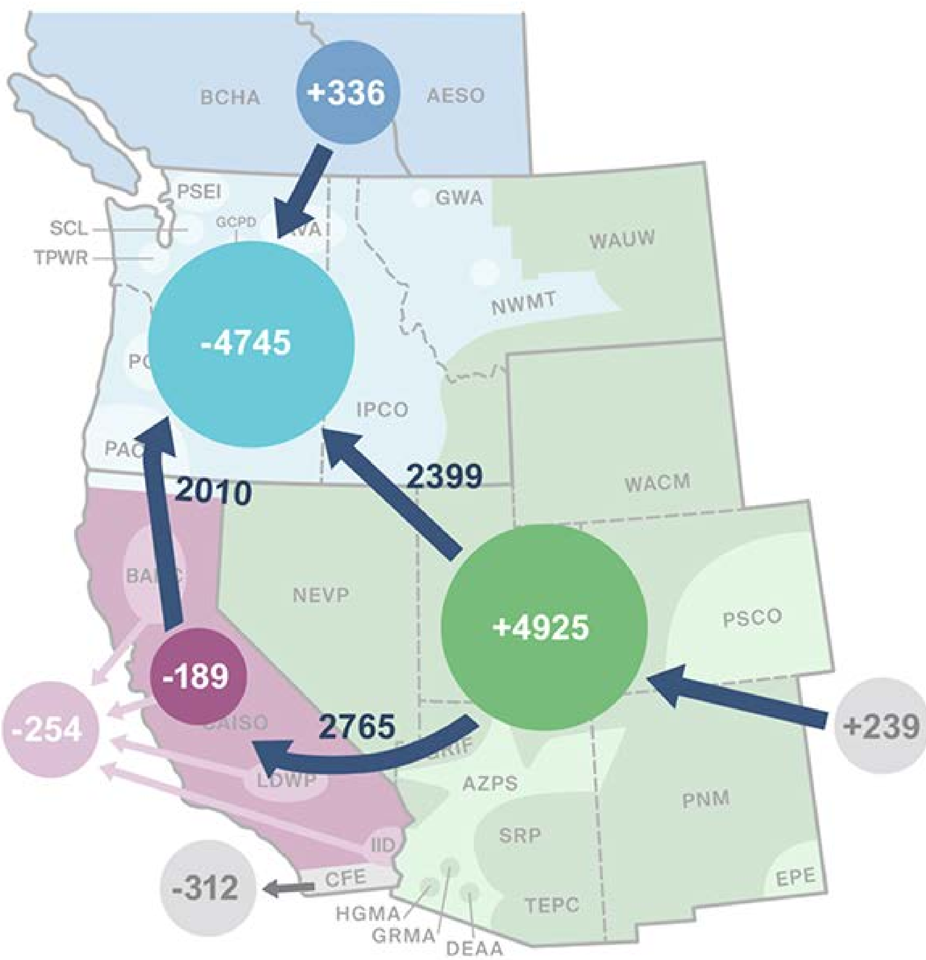
A new report from electricity marketer Powerex adds to the expanding debate around what transpired on the Western grid during a January cold snap that saw the Northwest forced to import large volumes of power in the face of record energy demand and tight supplies.

The storm saw five balancing areas — including the Alberta Electric System Operator — enter various levels of energy emergency alerts (EEAs), with one critical EEA-3 declared in the U.S. Northwest.

The March 6 report from the Vancouver, Canada-based company, which markets BC Hydro's surplus generation and manages a sophisticated trading operation that covers the Western Interconnection, represents yet another salvo in the dispute over the Jan. 12-16 winter freeze that plunged the Northwest to near-
record low temperatures.

The ensuing disagreement about how energy flowed during the event has largely reflected fault lines among Western electricity industry stakeholders in the contest between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+. The debate is sharpening as the Bonneville Power Administration nears the release of its market "leaning" in April. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

Powerex so far is the only Western entity to tentatively commit to Markets+. Its report, "Analysis of the January 2024 Winter Weather Event," amplifies the view held by some Northwest stakeholders that the region largely weathered the event because of support from the Desert Southwest and the Inland West — and not CAISO and other California balancing areas.



Map shows how power flowed across the Western Interconnection during the January cold snap in the Northwest and estimates of average hourly net imports/exports during the five-day event. | *Powerex*

The report also notes that Powerex itself aided its southern neighbors during the freeze. It additionally delves into the capacity and fuel supply challenges that confronted the Northwest and concludes with a set of recommendations to the region to prepare for similar future events — all of which notably exclude participation by CAISO.

Interpreting the Data

Powerex's report shows peak demand in balancing areas across the U.S. Northwest during the cold snap generally ranged about 2 to 6% higher than during a similar weather event in December 2022, with comparable temperatures. In PacifiCorp's West area, the peak was 6.7% higher than during the 2022 event, while Seattle City Light's peak was 6.2% higher and Idaho Power's 5% higher. British Columbia set a new demand record Jan. 12, beating its previous mark by 3%.

"This is consistent with recent projections of accelerating demand growth for U.S. Northwest utilities," the report said, citing last year's *forecast* from the Pacific Northwest Utilities Conference Committee.

Powerex's account of how power flowed across the Western Interconnection during January's five-day event aligns with two separate assessments from the Western Power Pool (WPP) and the Public Power Council (PPC).

Relying on Open Access Same-Time Information System (OASIS) transaction schedules, BPA's Pacific AC Intertie data, Energy Information Administration interchange data and figures from CAISO's OASIS, Powerex estimated that the U.S. Northwest hourly net energy imports averaged 4,745 MW during the 4 p.m.-to-8 p.m. periods of peak demand during the January event.

The "most significant" source of supply during those hours, Powerex said, originated in the Rockies (2.399 MW exported) and Desert Southwest (2,765 MW exported) regions, with power from the latter being wheeled through California into the Northwest. Canada — mostly Powerex — also exported an hourly average of 336 MW directly to the U.S. Northwest.

CAISO/West News

"In contrast, [CAISO], and other California utilities that are not part of [CAISO], were net importers on average of approximately 443 MW (189 MW and 254 MW respectively) during these peak demand hours," the report said, repeating a point made by the WPP and PPC in their analyses.

Across the full 120 hours of the January event, the U.S. Northwest imported an hourly average of 5,241 MW, Powerex said, with the Southwest exporting an hourly average of 3,223 MW and the Rockies 2,399 MW, with Canada exporting 481 MW. Over the same period, CAISO and other California BAAs were net importers of 49 MW and 489 MW, respectively, the report said.

"Imports and exports can be the result of bilateral transactions arranged prior to the operating hour and scheduled through e-Tags under the contract-path framework, or they can be the result of participation in the Western EIM, which optimizes transfers based on available supply and transmission service across the footprint," Powerex said.

The report cites WEIM data showing the Northwest received an average of 348 MW of supply from the WEIM across all hours and 164 MW during the peak hours. It notes that "most of the [Northwest's] imported supply was transacted in the bilateral markets (including exports from the CAISO using the intertie bidding framework and contract path scheduling), with the Western EIM providing a relatively small volume."

CAISO contested that characterization of energy flows in its own 80-page analysis detailing how the ISO and the WEIM supported the Northwest during the cold snap. (See *NW Freeze Response Shows WEIM Value, CAISO Report Says*.)

CAISO's report, also published March 6, said the ISO "became a net exporter over the Martin Luther King Jr. Day weekend for all hours of the day, excluding WEIM transfers," with hourly exports in the day-ahead and real-time markets exceeding 6,000 MW.

The ISO said WEIM transfers into CAISO stemmed from not limited supply within CAISO but instead the "economic displacement and opportunities optimized by the market and bounded by the transmission and transfers availability in the wider footprint."

"The market identified least-cost solutions within the wider WEIM footprint, transferring lower-cost electricity from the Southwest into California," the CAISO report said. "These transfers allowed exports scheduled in the day-ahead and hour-ahead markets to flow to the Northwest, replacing more expensive generation while managing congestion on key transmission lines."

'Distinct Reliability Challenges'

The Powerex report highlights "two separate and distinct reliability challenges" confronting the Northwest during the deep freeze: "inadequate capacity during peak demand hours" and "insufficient fuel supply across the multiday event."

Regarding fuel supply, the report notes that BC Hydro and BPA hydroelectric generators associated with the largest storage reservoirs can operate "at or near maximum output across all hours of a multiday weather event," but run-of-river hydroelectric facilities don't have that option.

"The region's dependence on these hydroelectric generation facilities gives rise to a risk of fuel supply insufficiency during weather events lasting multiple days, such as the January 2024 event," Powerex said. "The risk that other variable energy resources, such as wind facilities, may also experience persistent reduced output during a multiday weather event also contributes to fuel supply risk."

Powerex said that risk was evidenced by the fact that U.S. Northwest wholesale electricity prices were high in both the day-ahead and real-time market across all hours of the event, including in the WEIM, where prices hovered near caps.

The fuel supply risk also was apparent in the number of EEAs declared outside peak demand hours, including one during the overnight hours when demand was relatively low — "indicating a reliability challenge other than a lack of generating capacity to meet peak demand, such as a lack of fuel supply," Powerex said.

WRAP Enhancements

The report concludes with four key recommendations for the U.S. Northwest.

The first is for the region to consider making "enhancements" to the WPP's Western Resource Adequacy Program (WRAP) before it begins its first binding winter season, which could be as early as 2026/27.

Given the surge in peak demand compared with the region's December 2022 event, Powerex calls for the WRAP to potentially revise its winter peak demand assumptions, evaluate how well demand response (DR) programs reduced demand during the January 2024 event and "explore a regional discussion of the opportunities" to expand the use of DR during such multiday events. The report also asks the WPP to evaluate how WRAP resources performed during the event to get a better read on the current resource adequacy situation and identify ways to improve the program.

The report's first recommendation also contains a provision asking the WRAP to consider modifying how it transitions to its binding phase by accounting for utility capacity deficiencies that result from delays in obtaining interconnection for resources.

"This new transition framework may include a requirement that entities demonstrate that their current capacity deficits are temporary, or otherwise provide confidence of meeting resource adequacy requirements by the end of the new transition period," Powerex wrote.

Circumventing California

Powerex's second recommendation calls for the Northwest to use existing transmission facilities to increase import capability directly from the Southwest and Rockies regions. The report says that "additional supply appears to have been available in the Southwest and Rockies, but access to this supply appears to have been primarily limited by interregional transmission service."

Bound up in this recommendation is a criticism of CAISO's practices and a plug for Markets+

"Transfers of electricity across the West are limited by contract-path scheduling limits on key transmission paths. In addition to applying to deliveries of forward, day-ahead and real-time bilateral transactions, these limits are also applied by [CAISO] to transfers between BAAs in the Western EIM and will be applied in its proposed EDAM," the report says. "In contrast, organized markets elsewhere in the U.S. — as well as the proposed [SPP] Markets+ platform — do not generally layer contract-path limits on top of standard flow-based transmission limits."

The report's third recommendation, for the Northwest to upgrade and build new transmission connections with the Southwest and Rockies regions, includes another critique of CAISO practices. During the January event, Powerex and other Northwest entities have contended, the $650/MWh wholesale power price spread between the Northwest and Southwest was squeezed by congestion charges at CAISO's border with Oregon. An additional 2,000 MW of direct transfer capability with the Southwest could have saved the Northwest $140 million and reduced the region's reliability risk, Powerex said.

"Notably, roughly half of the deliveries from

CAISO/West News

the Southwest and Rockies region to the U.S. Northwest region during the event flowed through California, and particularly through the California ISO's service territory. Transmission service through the California ISO's service territory is provided under different terms and conditions than transmission service provided throughout the rest of the West," the Powerex report said.

CAISO has sought to address that contention, arguing that it is the only balancing authority in the West that uses mechanisms to manage transmission congestion in the day-ahead market and that it cannot overlook resolving situations in which it can foresee stress on a portion of the grid. The ISO's March 6 report said EDAM "provides additional mechanisms for managing congestion on either side of balancing area borders for participating entities and provides transparency on the distribution of congestion revenues collected through nodal pricing."

Overcoming Fuel Supply Challenges

Powerex's fourth recommendation urges the Northwest to consider how specific resources and resource types contribute to the fuel supply challenges that can arise during multiday events like the January cold snap.

The report notes that resources with "base load or dispatchable capabilities," such as hydro with longer-term storage — like that operated by BC Hydro — as well as nuclear, gas, coal and geothermal resources, "are able to contribute at a very high level" to meet the region's RA and fuel supply challenges.

"At the other end of the spectrum are shorter and medium duration storage facilities, such as batteries and pumped storage hydro," the report says. "These technologies contribute substantially towards meeting capacity challenges (through 4-hour or longer discharge cycles) but do little to address (and may actually exacerbate) multiday fuel supply challenges, as they do not provide net energy over the course of one or more full charging/discharging cycles (i.e., they actually consume energy across each day of a multiday event due to cycle losses)."

The report also points out that solar and wind resources might contribute differently from each other, with solar providing "little to no benefit" for capacity challenges occurring after sunset, while wind could be available during those intervals, depending on conditions.

"At the same time, these same solar resources may provide a greater contribution to fuel supply challenges over multiday events than wind resources, since wind resources may be more susceptible to multiday periods of little or no wind output," the report said.

"Ultimately, the WRAP may need to evolve to include additional resource adequacy requirements associated with multiday fuel sufficiency requirements," it said. ■

CAISO/West News

FERC Approves Most of CAISO's Rule Changes for EDAM Participation

By James Downing

FERC has issued an order partly approving rule changes CAISO filed to its tariff that are meant to enable its participation in the Extended Day-Ahead Market (EDAM) once it goes live (*ER24-379*).

The EDAM tariff is the largest and most complex suite of software enhancements since CAISO's market redesign and technology upgrade almost 15 years ago, and it requires the ISO itself to change its internal rules to participate smoothly.

On March 7, FERC accepted all of the proposed rules except for the proposal to calculate EDAM historical revenue recovery, which drew a protest from Southern California Edison.

EDAM participation might affect the allocation of revenues that transmission owners get for using their transmission system, and the ISO proposed an "EDAM access charge" to recover any shortfalls relative to historical revenues.

The charge is designed to recover three types of costs: foregone historical transmission revenue from sales of short-term firm and nonfirm transmission products under the transmission service provider's tariff; any new lines that get approved to increase transfer capability between EDAM entities based on the proportional ratio of historical short-term sales to overall historic transmission revenues; and foregone revenues for the use of the grid when wheeling through transfer volumes in a balancing authority are greater than total import and export transfer volumes for it.

SCE did not take issue with the three allocation components for calculating revenue, but it protests the inclusion of "subscriber" participating transmission owners or other PTOs in the allocation of EDAM recoverable revenue.

The subscriber PTO model allows developers building lines to bring renewables from out of California that are not picked by the ISO's planning process by signing up "subscribers" who will pay for the transmission line, which would be controlled by the ISO once operational. (See *CAISO Board OKs Plan to Admit Subscriber-funded Transmission Lines*.)

The subscriber model is new, so none of them will have historical costs and they would not provide transmission service because the ISO does that, SCE said.

SCE also argued the rules would provide windfalls to any subscriber PTOs just because they exist. CAISO argued it has limited the rules so subscriber PTOs will not get any undue revenue.

FERC did not weigh in on the dispute, but having rejected a related rule in the EDAM filing, it also rejected the historical cost recovery proposal without prejudice so something could be refiled after the marketwide rules are worked out. (See *CAISO Wins (Nearly) Sweeping FERC Approval for EDAM*.)

FERC accepted the other rules revisions, including settling transfer system resources, settling transfer revenue, settling EDAM resource sufficiency evaluation failure surcharges and enabling the net EDAM export transfer constraint.

The Department of Market Monitoring told FERC the net export transfer constraint limits were well designed to prevent the shifting of the responsibility for load curtailment from one EDAM participant to another. The method must allow enough flexibility to cover the dynamic nature of other EDAM entities' load and resource uncertainty, DMM said. ■

CAISO Control Room | *CAISO*

CAISO/West News

WAPA DSW Cites Lack of Benefits in Markets+ Withdrawal

Internal Presentation Gives Some Insight into Reason for Decision

By Robert Mullin

The Western Area Power Administration's Desert Southwest Region (DSW) pulled out of the second phase of developing SPP Markets+ after determining it would see few benefits from participating in either Markets+ or CAISO's Extended Day-Ahead Market, the federal power agency told *RTO Insider*.

"For our Desert Southwest Region (DSW), the potential benefits of day-ahead market participation for either market are minimal; therefore, DSW has decided to not continue as a funding participant in the Markets+ development at this time," WAPA said in an email March 5.

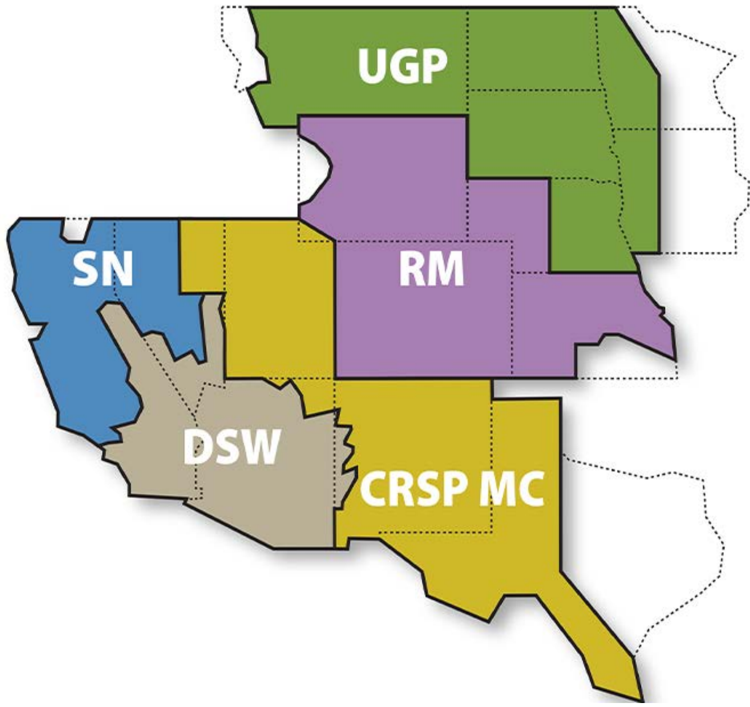
The agency said it will continue to monitor developments around both Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

"More information and a compelling business case would be necessary for the region to proceed with either day-ahead market option," it said.

DSW operates the Western Area Lower Colorado (WALC) balancing authority in western Arizona and sells federal hydroelectric power and provides transmission service to nearly 70 cities, electric cooperatives, Native American tribes, government agencies and irrigation districts. One of its customers, Arizona Electric Power Cooperative (AEPCO), includes six distribution cooperatives and five public power entities that serve more than 420,000 residential, agriculture and corporate customers in Arizona, California, Nevada and New Mexico.

SPP Vice President of Markets Antoine Lucas informed the Interim Markets+ Independent Panel (IMIP) of DSW's move March 1 shortly after the RTO received a letter from the agency stating its intent to withdraw from the effort and end its associated funding agreement. The announcement coincided with the IMIP's approval of the Markets+ tariff, which is headed for a March 25 vote by SPP's Board of Directors. (See *MIP Sends Markets+ Tariff on to SPP Board*.)

A WAPA spokesperson said agency officials involved with the matter declined *RTO Insider*'s request to release the letter. But a Jan. 31 internal slide presentation titled *DSW Markets Update* provided insight into the agency's decision-making.



WAPA DSW's balancing authority area is limited to western Arizona, but it's customer reach extends well into neighboring states. | *WAPA*

A section of the WAPA presentation appearing under the heading "AEPCO Update" reviews the results of the 2023 study that was commissioned by the Western Markets Exploratory Group (WMEG) and conducted by Environmental+Energy Economics (E3). The study examined potential costs and benefits associated with Western utility membership in Markets+ and EDAM under different scenarios reflecting various footprints in each market.

The 26-member WMEG had asked E3 to limit the scope of the study's cost-benefit analysis to variable production costs and energy market prices, while not considering potential investment savings from lower capacity needs due to resource and load diversity, the ability to procure resources over a wider geographic area and coordinated regional transmission planning.

"Other market studies have shown those other benefit categories can create two to ten times the impact of production cost savings alone," E3 cautioned at an Oct. 23 workshop hosted by the Bonneville Power Administration to present the results.

Results from the WMEG study indicated California would be the biggest financial beneficiary of a single day-ahead market covering the entire U.S. portion of the Western Interconnection, with most other entities in the West benefiting more from a two-market outcome. (See *Study Shows Uneven Benefits for Calif., Rest of West in Single Market*.)

The study showed that, under an "EDAM Bookend" scenario in which EDAM encompasses the West, California entities would save $80 million a year compared with business as usual, while most WMEG entities — including DSW/WALC (which excludes AEPCO) — would spend $20 million more.

Under a "Main Split" scenario, in which EDAM consists of California and PacifiCorp's balancing authority areas, California would spend $247 million more, while the majority of WMEG entities would save $26 million. But DSW/WALC still would be a net loser in that scenario.

The "AEPCO Update" in the WAPA presentation outlines a handful of key takeaways regarding the WMEG study, offering the view that the study shows "modest" overall differences in production costs between the footprints and saying the "results vary significantly by entity."

Another takeaway: that "one market is more efficient than two markets," with two markets requiring additional transmission to be built between the Northwest and Southwest.

Perhaps the most significant conclusion is the view, raised by E3, that the WMEG study "did not consider benefits which can be significantly larger in impact than production cost savings," including "coordinated generation and transmission planning and investment," "resource procurement savings" and "reliability improvements during extreme weather or challenging operational conditions."

The "AEPCO Update" also points out that DSW/WALC incurs losses in all but two WMEG scenarios. The first is the "Alternative Split 1," in which the Northwest, Colorado and eastern Wyoming participate in Markets+ while the rest of the West joins EDAM. Under that scenario, the agency saves $8.3 million in 2026. "Alternative Split 2" is a variation on that scenario with even lower participation in Markets+. It saves DSW/WALC $4.8 million.

The presentation notes that the benefits in both scenarios result from increased wheeling revenue and net cost savings from California's surplus solar.

The AEPCO portion of the presentation concludes with a slide labeled "Day-Ahead Market Strategy," which states that the WMEG study results "are somewhat dated, but they reflect the limitations of DSW hydropower and realities of the current transmission footprint." The slide also notes the cost and difficulties "of implementation/transition" related to joining a new market and "uncertainty" surrounding "which or whether either option becomes viable and/or more advantageous for DSW."

"Conclusion is for DSW to wait for the foreseeable future," the slide says.

EDAM Impact?

DSW's decision to pull out of Markets+ comes amid an intensifying contest between Markets+ and CAISO's Extended Day-Ahead Market (EDAM) ahead of the anticipated release of the Bonneville Power Administration's market "leaning" in April. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

DSW's decision doesn't exactly spell a victory for EDAM, but it does benefit CAISO by keeping DSW within the ISO's Western Energy Imbalance Market, which the federal agency entered in 2023. Arizona utilities Arizona Public Service, Salt River Project and Tucson Electric Power all have been key participants in developing Markets+, and industry sources have told RTO Insider the Arizona group, along with the Bonneville Power Administration and Powerex in the Northwest, are leaning toward the SPP market.

It's difficult to predict how DSW's decision will affect other Southwest utilities' choices. The agency operates about 3,100 miles of transmission lines, including the Parker-Davis Project, Intertie Project, Central Arizona Project and ED5-Palo Verde Hub Project — the last of which connects to one of the major electricity trading hubs in the Western U.S.

DSW's WALC last year got $59.35 million in gross benefits from the WEIM over the three quarters it participated in the market, according to CAISO. Those benefits consist of "cost savings, increased integration of renewable energy, and improved operational efficiencies, including the reduction of the need for real-time flexible reserves," the ISO says.

The Jan. 15 WAPA presentation shows DSW saved $8.6 million from April to October 2023 compared with the same period in 2022, against CAISO's net benefits figure of $43.23 million for the first and second quarters of last year.

SPP spokesperson Meghan Sever said the RTO "understands each entity must decide whether participation in a market provides the most benefits for its customers."

"While we respect any valuable Markets+ participant's individual decision, SPP believes Markets+ is still a great option for a market that provides financial benefits and enhances electric reliability in the Western Interconnection," Sever said. "We thank WAPA DSW for their participation in Phase 1 of Markets+ development and hope they will continue to be involved in the Markets+ stakeholder process."

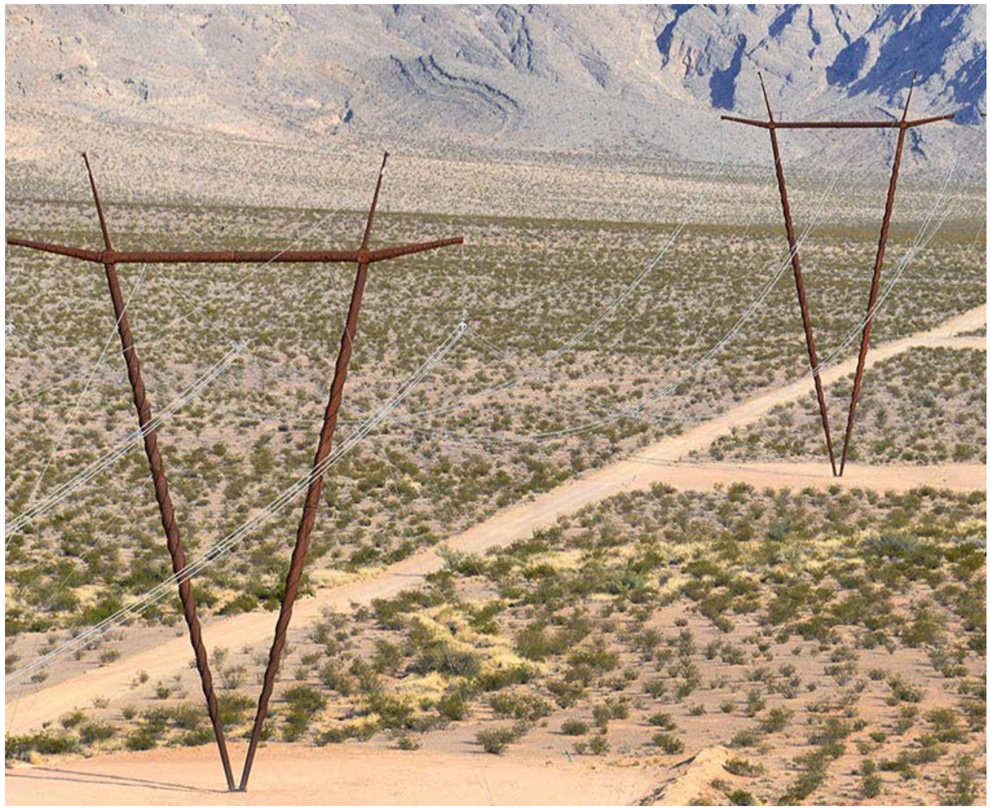
In its email to *RTO Insider*, WAPA said it "will remain engaged and assess potential opportunities for both day-ahead initiatives to ensure we are well positioned to continue providing the best service to our customers on a region-by-region basis." ■

CAISO/West News

RTO, Day-ahead Choice Closely Linked, Nev. Effort Shows

Market Decisions Across Western States also Interrelated, PUCN Process Participants Say

By Elaine Goodman



NV Energy's One Nevada transmission line. | *DOE*

NV Energy is aiming to bring a proposal to Nevada regulators by the end of the year for joining a day-ahead market, but what process regulators will use to evaluate that request is still very much up in the air.

"It would be good for our internal purposes and potentially for others in the West, because a lot of the utilities in the West feel that their market decisions are based in not insignificant part on what their neighbors are doing," David Rubin, NV Energy's federal energy policy director, said during a March 4 workshop. "There are clearly relationships, for example, between Nevada and Idaho."

Rubin said that by filing a proposal with the Public Utilities Commission of Nevada (PUCN) by the end of the year, NV Energy could let others know the company's intentions before they have to decide on making a "fairly significant" financial commitment for the next phase of SPP's Markets+. CAISO's Extended Day-Ahead Market (EDAM) and Markets+ are competing to attract day-ahead market participants.

Rubin said the interrelationship among utilities in the West when it comes to day-ahead markets is underscored by recent studies, including a just-released report from Brattle Group, which found greater economic benefits for NV Energy if the utility went with EDAM rather than Markets+. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)

PUCN Investigation

Rubin's comments came during a PUCN workshop conducted by Commissioner Tammy Cordova, the presiding officer in an investigation of regional market activities in the West. In addition, state law requires NV Energy to join an RTO by 2030, and the investigation will look into how the PUCN will oversee that process.

NV Energy and other interested parties filed written comments on the matter ahead of the workshop. (See *Nev. Regulators to Weigh Approaches to RTO Membership*.)

Some commenters said the commission could consider an NV Energy proposal to join a day-ahead market through its energy supply plan (ESP) — a process that was used in 2014 when the utility decided to join CAISO's Western Energy Imbalance Market (WEIM). But joining an RTO would be more complex, and new rules from the PUCN might be needed, some said.

During the workshop, Shelly Cassity of the PUCN's regulatory operations staff said joining a day-ahead market is "a much bigger step" than becoming a WEIM member. And the 135-day timeline for evaluating an ESP is relatively short, she said.

"We think that the ESP process may not be the ideal route," Cassity said. "We think regulations may be necessary."

Similar Issues in Colorado

In considering day-ahead market and RTO issues, the PUCN may look to Colorado, where the legislature in 2021 passed a bill requiring utilities to join an RTO by 2030, similar to Nevada's Senate Bill 448. The Colorado Public Utilities Commission has been working on rules to guide the process of joining a day-ahead market or RTO and recently released draft regulations.

During the PUCN workshop, Brian Turner, a director at Advanced Energy United, said the Colorado PUC is looking at splitting the decision about utilities joining an RTO into two parts: whether the RTO meets criteria laid out in statute and then whether joining an RTO is in the public interest.

The definition of an RTO in Nevada's SB 448 includes requirements that the organization be FERC approved, improve reliability in the state and have a governance structure that's independent of transmission users.

Cordova indicated she was open to considering Colorado's approach.

"As we keep telling people, this is Nevada, it's not Colorado," she said. "But I am also a big fan of not creating a wheel that I didn't have to invent."

PUCN's March 4 workshop is expected to be followed by additional workshops, including at least one focused on the Brattle Group findings and other studies of potential market benefits.

Cordova said she'd issue a procedural order laying out a timeline for the proceedings in the next week or so. ■

CAISO/West News

Colorado PUC Sets Rules for Electricity Market Participation

State's Utilities Have 3 Potential Markets to Join

By Tom Kleckner

The Colorado Public Utilities Commission has issued proposed rules that would govern how it will review applications from state utilities wishing to join the various regional electricity markets being developed in the Western Interconnection.

The rules implement a 2021 state law by setting out utility filing obligations, timelines, a legal standard of review and required PUC findings depending on the type of transmission utility, the nature of the market and relevant policy concerns based on prior commission studies, cases and comments (*22R-0249E*).

The rulemaking includes 10 *conditions* for market participation that reflect state law and the PUC's policies. They include grid reliability, emissions tracking, customer rate impacts and transmission expansion for investor-owned utilities. Utilities also can keep a percentage (35%, to begin with) of the savings they gain from the markets.

PUC Chair Eric Blank said in an email to Western regulators that his agency's primary concern is to develop a "consistent framework for tracking and accounting for [greenhouse gas] emissions" and maintain an interconnection queue process that allows winning projects to move forward in a timely manner. It also has more general concerns over rates, transmission expansion and seams.

The commission said it is important for Colorado utilities, regulators and other stakeholders to become involved in market development before market operators submit their tariffs for FERC approval because any subsequent changes will depend on the markets' governance structures and stakeholder processes.

"Given these timing and other challenges surrounding the FERC approval and modification process, the best opportunity for Colorado utilities, regulators, customers, [independent power producers], clean energy advocates and others to shape the key aspects and structure of the regional market options may be prior to the FERC filings," the PUC wrote. "Once a tariff is filed at FERC, additional changes can be challenging and time consuming to get approved and implement."

The PUC held a March 5 hearing on the rules and is currently gathering written feedback from interested parties. It plans a full review following the comment period, which ends April 5.

Market Choices

Colorado utilities can participate in any of three regional markets currently planned for the West:

- CAISO's *Extended Day-Ahead Market*, which already has FERC approval and is due to go live in 2026. PacifiCorp and the Balancing Area of Northern California (BANC) are its only two committed participants so far, although the Los Angeles Department of Water and Power has signaled its intent to join.
- SPP's RTO West seeks to extend the services SPP currently offers in the Eastern Interconnection. It, too, is targeted to go live in 2026 and has seven utilities evaluating whether to place their facilities under its tariff, which is expected to be filed midyear.
- SPP's Markets+ and its bundle of proposed services that would centralize day-ahead and real-time unit commitment and dispatch across a large footprint in the Western Interconnection. A tariff filing is planned for the end of March.

Eric Blank's Colorado Public Utilities Commission has issued draft rules for participation in organized markets. | © RTO Insider LLC

CAISO and SPP also both have imbalance markets operating in the interconnection. The PUC noted Colorado participants in the latter's Western Energy Imbalance Service (WEIS) market suggest that optimizing dispatch in real time has already reduced curtailment and lowered production costs in Colorado.

SPP has already been working with Western stakeholders to develop a market solution, best practices, rules and protocols that support the Northwest's only cap-and-trade program in Washington. Spokesperson Meghan Sever said the RTO is reviewing the proposed rules and has been working "extensively" with the Colorado commission and utilities on GHG emissions tracking and accounting.

"We foresee no issue complying with the proposed rule as drafted," Sever said. "While these proposed rules are more directed toward Colorado utilities, SPP sees no barriers in our ability to comply with the proposed rule."

Colorado Springs Utilities (CSU) and Tri-State Generation and Transmission Association are among the state's utilities that are evaluating SPP RTO West. Both are already members of the RTO's WEIS market that went live in 2021.

Steve Berry, a senior public affairs specialist with Colorado Springs Utilities, said it is premature for the utility to offer a formal position on the proposed PUC rules.

"We've been an observer of the process up to this point," he said.

Tri-State did not return a request for comment. It has already told the PUC it intends to transition its load within the Western Area Colorado Missouri balancing area, which includes portions of Colorado, Wyoming, Western Nebraska, New Mexico and Arizona, into RTO West in April 2026. ■

CAISO/West News

NV Energy OK'd for Coal Plant Conversion, Solar+Storage Project

Nevada Regulators Approve Projects as Part of IRP Amendment

By Elaine Goodman

Nevada regulators approved NV Energy's plan to convert its last coal-fired power plant to natural gas, while also allowing the company to move forward with a $1.5 billion, 400-MW solar-plus-storage project.

Approval of the solar-plus-storage project, known as Sierra Solar, may allow the utility to reduce an open position that's been described as one of the largest in the West. NV Energy is developing the project, which would be about 15 miles northeast of Fernley in northern Nevada.

But whether Sierra Solar will be built remains to be seen.

In an order approved March 1, the Public Utilities Commission of Nevada (PUCN) set conditions on Sierra Solar including payment of damages to ratepayers if the project is delayed or doesn't perform as expected.

The order admonished NV Energy for arguing that it needed to move forward quickly with the project, then balking at conditions. It quoted NV Energy's response when asked about a maximum project cost: "If the commission … feels like it has to have an upper limit on costs, we'll assess if we think it's reasonable and whether we can move forward with the project or not."

"The commission is persuaded that there is a resource adequacy need necessitating consideration of the Sierra Solar project now and is troubled by the suggestion that this need may be ignored unless NV Energy gets the terms that it desires for the Sierra Solar project," the commission wrote in its order.

In a news release after the commission's vote, NV Energy said it "is diligently reviewing the conditions the commission placed upon the project."

Planning Process Questioned

NV Energy proposed the Sierra Solar project through the fifth amendment to its 2021 Integrated Resource Plan. The amendment also proposed the conversion of the North Valmy Generating Station, NV Energy's last coal-fired plant, to run on natural gas through 2049.

PUCN largely approved the amendment, despite objections of stakeholders who said the projects should go through a more compre-

Nevada regulators approved NV Energy's proposal to convert the coal-fired North Valmy plant to natural gas. | *Ken Lund CC-BY-SA-2.0 via Wikipedia Commons*

hensive evaluation as part of the utility's 2024 IRP that will be filed this year.

Instead, the utility has resorted to "crisis planning" through multiple amendments to the IRP, said Emily Walsh, clean energy policy adviser at Western Resource Advocates. Walsh noted that the cost of projects proposed in the fifth amendment far exceeded that of projects in the 2021 IRP.

"They've really been gaming the IRP process," Walsh told *RTO Insider*.

In addition to approving Sierra Solar and the North Valmy conversion, the commission authorized a 2049 retirement date for two gas-fired units at the Tracy power plant, which had been scheduled for closure in 2031.

But the commission declined to approve an asset purchase agreement for future development of the 149-MW Crescent Valley solar-plus-storage project about 50 miles from the Valmy plant. Because the project is at an early stage, the utility can bring the proposal back as part of its 2024 IRP, the commission said.

Open Position

One of the drivers behind NV Energy's proposals was to reduce its open position — resource needs that are met through short-term market purchases rather than by utility-owned resources or long-term contracts.

In a survey of 13 Western utilities, NV Energy's projected open position in 2025 was 1,092 MW, second only to that of PacifiCorp's 1,637 MW, according to testimony filed with PUCN on behalf of the utility. As a percentage of peak demand, NV Energy's open position was 13%, ranking sixth out of the 13 utilities.

Proposals in NV Energy's IRP amendment would reduce its open position to 820 MW in 2026, representing 10% of peak demand.

The commission's order also addressed NV Energy's participation in the Western Resource Adequacy Program, directing the utility to postpone its financially binding season from winter 2026/27 to winter 2027/28.

"NV Energy's [forecast] open position for the summer of 2027, with or without commission approval for the requests in this docket, would subject NV Energy to substantial penalties that could be passed on to ratepayers," the commission wrote.

Valmy Solution

In its 2021 IRP, NV Energy planned to replace capacity from the coal-fired North Valmy Generating Station with the Iron Point and Hot Pot solar-plus-storage projects. The utility plans to end coal combustion at Valmy by the end of 2025.

But supply chain issues derailed the solar projects, according to the utility, which then proposed a 200-MW battery storage project as a partial solution for the Valmy retirement. The commission rejected the proposal, asking NV Energy to come back with a complete solution for Valmy. (See *NV Energy Rejected on Plan to Replace Coal Plant with Storage*.)

In its March 1 order, the commission approved the plan to convert Valmy to natural gas but granted only $50 million of the $83 million NV Energy wanted for the project.

The $50 million is NV Energy's actual costs for the project, the commission said, while the remaining $33 million is "just a placeholder amount associated with upgrades that may be needed at some point in the future."

NV Energy plans to split the cost of the Valmy conversion with Idaho Power, which is 50% owner of the plant.

NV Energy acknowledged that it initially didn't consider a gas conversion for Valmy. But a new transmission study found that an area called the Carlin Trend needs voltage support from a firm dispatchable resource.

The commission said the Carlin Trend constraint is "a real condition." In addition, "without Valmy, there is a high probability Nevada would have experienced rolling blackouts three out of the last four years," the commission stated in its order.

Once NV Energy's Greenlink West transmission line is completed, the Valmy plant may be able to run less often, the commission noted. ■

CAISO/West News

DMM: CAISO Transfer Limitations During Q3 Heat Waves Led to Price Disparities

'Not Clear' Why ISO Continued Limits Until November, Monitor Says

By Ayla Burnett

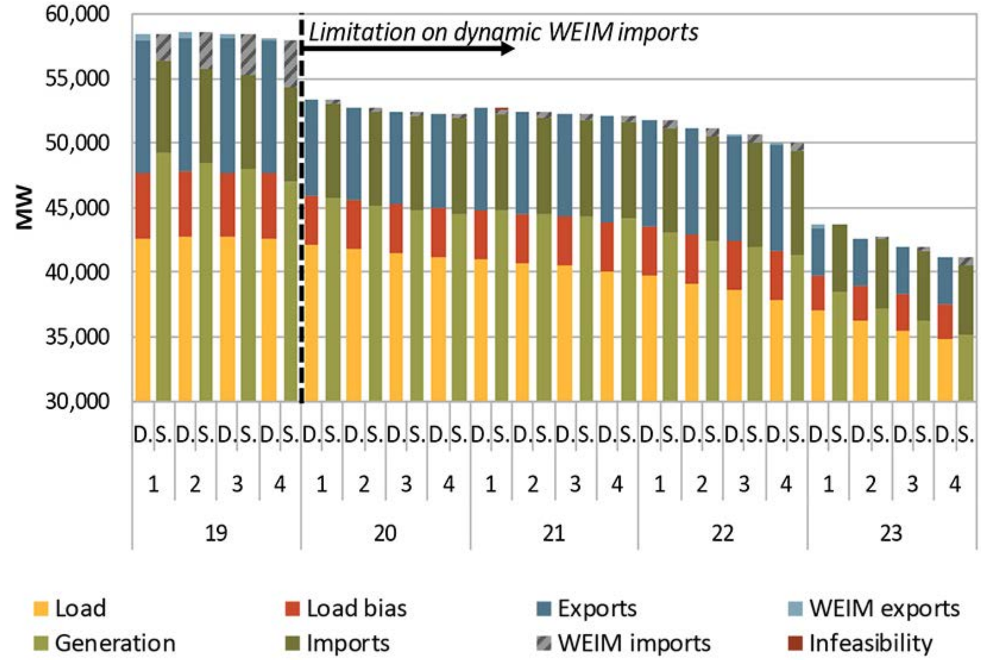
Limits on imports from the Western Energy Imbalance Market into the CAISO balancing authority area between July 25 and Nov. 16, 2023, led to increased transmission congestion in the ISO's 15-minute-ahead market and lower prices in the five-minute market, the Department of Market Monitoring told stakeholders March 6.

While CAISO operators' actions helped the ISO maintain reliability during a brutal summer in the West, "it is not clear why the CAISO area continued these transfer limitations after the mid-August heat wave and through Nov. 16," the department said. It recommended "that CAISO work with stakeholders to consider other methods of achieving the intended reliability outcomes without creating the large and systematic modeling differences between the 15-minute and five-minute markets."

Presenting the department's State of the Market *report* for the third quarter of 2023, Ryan Kurlinski, senior manager of market and policy analysis, said CAISO operators began limiting WEIM import transfers for the hour-ahead and 15-minute markets in late July when stressful weather conditions led to high levels of unfulfillable self-scheduled exports. (See *CAISO DMM: High Exports to Southwest Led to July EEAs*.) The limitations were then lifted in the five-minute market.

The limiting action was taken to mitigate the risk that during critical hours, internal generation and hourly block intertie schedules could be displaced by WEIM imports that might not materialize in real time. CAISO issued energy emergency alerts on three days in late July but was not forced to shed load.

"This limitation on these tight days did have the intended effect of reducing advisory WEIM imports into CAISO and replacing it with increased hourly block imports and decreased exports out of CAISO," Kurlinski said. "While that limitation had the intended



From July 26 to Nov. 16, 2023, CAISO limited WEIM import transfers into its balancing authority area during net peak hours. | *CAISO*

reliability impact, it also significantly impacted the rest of the West," driving down prices.

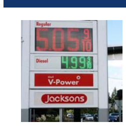
Load adjustments in the hour-ahead and 15-minute markets were lower on average in the third quarter than those in the same quarter in 2022, though after July 20, they rose back to 2022 levels of about 2,000 MW.

"The combination of high load adjustments in the 15-minute market and much lower adjustments in the five-minute market contributed to the lower average prices in the latter market," the report says. "When the CAISO balancing area limited WEIM transfer imports to zero in the hour-ahead and 15-minute markets, most of the WEIM footprint was collectively export constrained at a lower price based on regional supply conditions outside of the CAISO area," the report reads.

Kurlinski used transfers in and out of Arizona Public Service as an example. Before the transfer limitation was implemented, there were significant transfers from APS to CAISO and other BAs, but after the limitation was put in place in the 7-8 p.m. hour on July 26, dynamic transfers from Arizona to CAISO stopped.

The "DMM has recommended that CAISO work with stakeholders to consider if there may be other methods or other ways to try to achieve the same reliability outcomes that the CAISO BA is trying to achieve but without potentially creating this significant difference between the 15-minute market and five-minute markets," Kurlinski said. "At the very least, it would be good to have a more transparent discussion about what the ISO is seeing in its systems that would lead them to do this again and to be more transparent about when they are going to do this." ■

West news from our other channels



Suit Alleges Job Retaliation over Wash. Cap-and-invest Projections

NetZero Insider

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

ERCOT News

Veteran Monitor McDonald to Lead ERCOT's IMM

By Tom Kleckner

ERCOT headquarters in Austin, Texas | *© RTO Insider LLC*

The Texas Public Utility Commission *said* March 11 that Jeff McDonald, a 22-year market monitoring veteran, has been hired as director of ERCOT's Independent Market Monitor.

He replaces Carrie Bivens, who resigned as the IMM's director last year.

McDonald spent nearly eight years at ISO-NE as its vice president of market monitoring. Before that, he held several managerial positions during 14 years with CAISO's Department of Market Monitoring.

He will be responsible for collaborating with the PUC to detect and prevent market manipulation and identify potential design improvements for the ERCOT market, the commission said.

"Jeff's deep expertise and decades of experience make him the perfect person to lead the IMM team in Texas and ensure the market is operating efficiently, fairly and competitively," Potomac Economics President David Patton said in a statement.

Potomac Economics has served as ERCOT's IMM since 2005, when the organization was created. It recently was awarded another contract to monitor the market through 2027.

Bivens resigned in November after 3.5 years as the IMM's director following several disagreements with PUC and ERCOT leadership. She cast doubt on the performance credit mechanism pushed by former PUC chair Peter Lake and defended before the ERCOT board an IMM report that said the grid operator's newest ancillary service "likely" raised the real-time market's energy value by at least $8 billion. (See *Bivens Resigns as ERCOT's Market Monitor*.)

McDonald joins Potomac Economics from Concentric Energy Advisors, where he was the firm's vice president. He holds a Ph.D. in economics from the University of California, Davis, a master's in natural resource economics from the University of Massachusetts, Amherst, and a bachelor's in agricultural and managerial economics from Cal Davis. ■

ERCOT News

Texas Regulators Slow PCM's Development

PUC to Involve Itself, Stakeholders in Market Tool's Deployment

By Tom Kleckner

Texas PUC's Lori Cobos offers her comments on ERCOT's performance credit mechanism market tool. | *Admin Monitor*

Texas regulators have pumped the brakes on the proposed performance credit mechanism's (PCM) development, making it clear that they and stakeholders will be involved in the market tool's design.

"We need broader input, not just from commissioners, but also from stakeholders," Public Utility Commission Chair Tom Gleeson said during the agency's open meeting March 7.

ERCOT staff *filed a memo* before the meeting outlining a study approach for designing a PCM strawman. It identified 37 design parameter decisions and an evaluation methodology to select the final design, with several options for each parameter decision (*55000*).

Staff also suggested a timeline that includes three stakeholder workshops and PUC approval of the final design in early 2025. ERCOT would then develop necessary protocols and, following commission approval, "evaluate" the PCM's implementation.

"This timeline that's laid out in in your filing is very compressed, it's very rushed, and it completely leaves out the commission in terms of workshops and engagement and any kind of stakeholder feedback over here," Commissioner Lori Cobos told ERCOT staff.

Gleeson called the implementation evaluation in ERCOT's timeline "open ended."

"That wasn't a completion timeline," he said. "There's still work to be done in ERCOT through their protocols and through their system upgrades. The actual implementation of this would still be much further, so I just don't know that we have enough information now to have a timeline somewhere in 2026, 2027 mean anything at this point."

Further complicating the timeline is ERCOT's development of real-time co-optimization, scheduled to be deployed by Dec. 31, 2026. That market tool is designed to improve energy procurement and dispatch.

Cobos laid out a schedule beginning with PUC staff filing a memo before the commission's March 21 open meeting providing their input on ERCOT's proposed design parameters. The PUC again would consider the PCM during its April 11 open meeting before handing over its feedback to the ISO. That would move the date for the grid operator's first workshop from March 26 into April, with stakeholders submitting feedback to the PUC.

The commission agreed at least one of the workshops, likely the first, should be held at the PUC's offices, and that the Independent Market Monitor and ERCOT staff conduct separate studies on the mechanism's market effects.

"We need to have two data points, two views of how the PCM is going to cost and affect the market," Commissioner Jimmy Glotfelty said, stressing that design decisions are policy questions best taken up at the commission.

ERCOT has engaged Energy and Environmental Economics (E3) to support the strawman's development. E3 also worked with Astrapé Consulting at the PUC's direction to evaluate the PCM and five other potential market reforms. While the study did not recommend the PCM, then-Chair Peter Lake determined the mechanism would best incent more dispatchable generation. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

The PCM establishes a reliability standard and corresponding quantity of performance credits (PCs) that must be produced during the highest reliability risk hours to meet the standard. Load-serving entities can purchase PCs, awarded to resources through a retrospective settlement process based on availability during hours of highest risk, and trade them with other LSEs and generators in a forward market; generators must participate in the forward market to qualify for the settlement process.

The PUC adopted the PCM for inclusion into the ERCOT market in January 2023. Also last year, Texas lawmakers passed a bill (*HB 1500*) establishing legislative guardrails for the PCM's implementation.

The commission determined the PCM's $1 billion annual cap, as set by the Texas Legislature, is an "absolute" annual cost cap, not an average annual cap. ■

ISO-NE News

National Grid Backs out of Twin States Clean Energy Link Project

By Jon Lamson

Despite support from the U.S. Department of Energy, National Grid has backed out of a major project to significantly increase the two-way transmission capacity between New England and Quebec.

The news is a setback for efforts to increase bi-directional transmission connections between the regions, which could become increasingly important in coming decades as electricity demand increases and intermittent renewables proliferate.

A partnership between National Grid and the nonprofit Citizens Energy Corp., the Twin States Clean Energy Link was proposed as a 1,200-MW transmission line through Vermont and New Hampshire expected to cost about $2 billion.

The project was aimed at unlocking the potential of Canadian hydropower to fill in electricity gaps as intermittent renewable resources expand in New England. In this dynamic, New England would send power to Quebec during periods of renewable surpluses, while Quebec would send hydropower south during wind and solar lulls. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

While two under-construction transmission projects between Quebec and the Northeast U.S. (New England Clean Energy Connect and Champlain Hudson Power Express) are set to provide consistent baseload power to New England for decades, Twin States was the first major project focused on hydropower's balancing potential.

"The cancellation of Twin States is a blow to New England's decarbonization efforts," said Emil Dimanchev, the co-author of a 2021 *study* that found increased bidirectional transmission capacity between regions would help reduce the timeline and cost of grid decarbonization.

Dimanchev said the news indicates existing power market structures do not provide enough incentives for forward-looking transmission investments that would provide long-term benefits.

He added that the project's cancellation "is a symptom of the slow pace of wind build-out in New England. It shows us that there is a greater need for planning transmission and generation investments in a more coordinated fashion."

National Grid declined to elaborate beyond a brief statement on the reasons for the cancellation.

"National Grid has determined that the project is not viable at this time," the company wrote. "We will continue to pursue paths to building much-needed transmission capacity for the region and for our customers and communities."

"While we respect National Grid's decision to suspend development of the Twin States Clean Energy Link," Citizens Energy President Joseph Kennedy III wrote in a statement, "we are disappointed to lose this vital opportunity to help New England meet its green energy goals."

In October, DOE announced its intention to serve as an anchor off-taker for the project by purchasing up to 50% of the line's capacity to reduce development risk. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

"It's discouraging that a project that had such significant Department of Energy support could not make it across the finish line," said Joe LaRusso of the Acadia Center. "Broader U.S.-Canadian cooperation and coordination is still needed, because in the future we are going to have to have a grid that spans the entire Northeast Power Coordinating Council reliability zone."

Upper Kennebec Region of Maine | *Shutterstock*

New Hampshire officials expressed disappointment in response to the news. Donald Kreis, New Hampshire's consumer advocate, called using Canadian hydropower to balance renewables an "intriguing idea," but said the project's cancellation shows the lack of a business case for new transmission lines between New England and Quebec.

"There is a need for more transmission capacity in New England, [but] the merchant model — at least as premised on moving more power out of Canada — seems to be unraveling as a viable proposition," Kreis said.

In an *op-ed* written prior to the project's cancellation, Kreis expressed concern about a legislative *proposal* for New Hampshire to contract up to 240 MW of the line's capacity. Kreis said other states should step up to help fund the project.

"New Hampshire represents, at most, around 10 percent of New England's electric consumption," Kreis wrote. "If we are going to promise to fund a 1,200-megawatt transmission project intended to benefit the whole region, our fair share is, at most, 120 megawatts."

Hydro-Quebec, which had not signed a commercial agreement related to the project, expressed its disappointment with the cancellation while reiterating the company sees significant potential in increased bidirectional electricity exchange.

Serge Abergel, COO of Hydro-Quebec's U.S. operations, told *RTO Insider* the company will continue studying the potential of new two-way transmission projects.

As the deployment of intermittent renewables accelerates, "there's no doubt that the future has some sort of bidirectional agreement in store for Quebec and its neighbors," Abergel said, while emphasizing that the Twin States project was an early-stage attempt to build on hydropower's balancing potential.

"We just don't have enough information to convince people yet, nor do we have enough information to say this is not interesting," Abergel added. "Our work goes on." ■

ISO-NE News

NECA Renewables Conference Highlights Transmission Challenges

By Jon Lamson

From left: Andrea Hart, Atlantic Shores Offshore Wind; Josh Kaplowitz, Locke Lord; Joanna Troy, Massachusetts DOER; and Jerry Vincitore, Crédit Agricole CIB | *© RTO Insider LLC*

BOSTON — Transmission limits remain a major barrier to scaling up wind and solar energy to meet state decarbonization goals, speakers at the Northeast Energy and Commerce Association's Renewable Energy Conference said March 8.

The conference featured panels on offshore wind, resource interconnection and networked geothermal heating, but grid constraints were a major theme throughout the day.

"We are in full recognition that a lot of work needs to be done on the grid in order to interconnect a lot of offshore wind projects," said Joanna Troy, deputy commissioner of the Massachusetts Department of Energy Resources. Coordinating the planning and cost allocation for this transmission will be key components of scaling up offshore wind, she said.

Troy highlighted the work of the state's *Interagency Offshore Wind Council*, which is conducting stakeholder engagement for a "strategic offshore wind road map" the administration intends to release in late summer or early fall.

Andrea Hart of Atlantic Shores Offshore Wind stressed the importance of coordinating planning efforts for offshore wind transmission.

Connecting an increasing number of offshore wind projects in an uncoordinated manner could create a "spaghetti dilemma," with separate lines connecting to the shore at different points, Hart said. This could increase project costs, timelines, environmental impacts and local opposition.

Hart said separating offshore wind development and transmission into separate procurements can help reduce the development risks, highlighting ongoing processes in *New York* and New Jersey.

"States are starting to do this, but it is still in a piecemeal fashion," Hart said. "States aren't yet in this place where they can come up with transmission solutions that transcend state lines, that transcend ISO or RTO territory."

Hart added that until transmission solutions are "waiting and ready to be used by developers, generators are going to bake in a lot of risk into their prices."

Reducing the number of transmission lines landing onshore could also help reduce the opportunities for lawsuits from local opponents. The first wave of offshore wind projects under development has faced a series of so-far-unsuccessful lawsuits aimed at halting them. (See *Another Federal Lawsuit Seeks to Invalidate OSW Approvals*.)

Josh Kaplowitz, senior counsel at law firm Locke Lord, emphasized the importance of early and meaningful engagement with host communities.

"It's critical to go into communities early to share facts on the benefits of offshore wind, listen to concerns and adapt projects if feasible," Kaplowitz said. At the same time, "at this early stage in the industry, when people are still getting used to offshore wind, you're not going to prevent all lawsuits. It's unlikely that you're going to be so good at community engagement that no one's going to want to challenge projects."

The transmission constraints in New England are not limited to gigawatt-scale offshore wind projects; they also impact smaller onshore projects connecting to both the transmission and distribution networks.

Speakers on a panel focused on interconnection expressed cautious hope about the effects of FERC Order 2023. ISO-NE is planning to file its compliance proposal at the beginning of April. (See related story, *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance*.)

"I think it's a great step in the direction of holistic planning," said Sheila Keane, director of analysis for the New England States Committee on Electricity. "When I think about Order 2023 and the broader context of where we're going, we're going to need a lot more resources coming online."

Barry Ahern, director of transmission planning and asset management for National Grid, said he is "trying to remain on the optimistic side" regarding the impacts of the order on transmission interconnection.

The order will likely make it "more predictable when you will get your results, but more unpredictable on what they will be," Ahern added.

Weezie Nuara, assistant secretary for federal and regional energy affairs at the Massachusetts Executive Office of Energy and Environmental Affairs, applauded ISO-NE's incorporation of stakeholder input into the Order 2023 compliance proposal.

"It really does seem to be a good news story of the stakeholder process working for all of us," Nuara said. "Of course, there can be further improvements, and it remains to be seen how effective all these reforms will be. These are massive changes, moving from first-come-first-served to first-ready-first-served with a cluster study approach."

The order could also affect state-jurisdictional projects connecting to the distribution system, Nuara added.

"I'm very curious to see how the coordination with [affected system operator] studies plays out," Nuara said, adding that some interconnection customers to the distribution system "are also having to undergo transmission studies because they're just such large clusters of distributed generation requesting interconnection to the distribution system. So that is having knock-on effects on the transmission system, and ISO New England has gotten involved in a big way."

Nuara expressed hope that Order 2023 compliance "will maybe help corral some of the study work that's going on for [distributed generation] projects." ■

ISO-NE News

NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance

By John Cropley

NEPOOL on March 7 endorsed ISO-NE's package of proposed tariff revisions to comply with FERC Order 2023. | *© RTO Insider LLC*

The NEPOOL Participants Committee on March 7 unanimously approved ISO-NE's package of tariff revisions to comply with FERC Order 2023.

ISO-NE expects to submit the compliance filing April 1, two days before the deadline set by FERC in its efforts to unclog interconnection queues that have bogged down nationwide.

The vote follows months of deliberations that included a Feb. 15 NEPOOL Transmission Committee meeting at which an initial proposal, as well as six proposed amendments to it, failed to gain the two-thirds support needed for approval. (See *ISO-NE Order 2023 Compliance Proposal Fails to Pass NEPOOL TC*.)

ISO-NE incorporated several elements of the amendments into the final package, which was approved with only two abstentions.

The RTO summarized the post-Feb. 15 changes to the package in a *March 1 memo* to the committee:

- An interconnection customer may specify in its interconnection request for capacity network resource (CNR) interconnection service that the requested service be downgraded to network resource interconnection service under certain conditions.
- After the completion of a cluster study (not including the transitional cluster study), if the RTO determines that a cluster restudy is required (because of the withdrawal of other projects), the developer of a remaining project may request a specific one-time decrease in the size of the generating facility or elective transmission upgrade for the restudy.
- For customers with assigned queue positions as of 30 calendar days after April 1, but for which system impact studies are projected to be completed between May 1 and June 30, the RTO will still tender transitional cluster study agreements. However, if the SIS is complete and accepted by the customer by July 1, the request will no longer proceed to the transitional cluster study. Instead, the customer will be tendered an interconnection agreement pursuant to the applicable provisions in the respective interconnection procedures.
- Where a request successfully participates in the transitional CNR group study and then later obtains a capacity supply obligation in the Forward Capacity Market, the rules governing any termination of the CNR capability will be governed by the relevant FCM rules.

"Importantly, each of these additions can be incorporated without adding to the overall time frames or decreasing the efficiency of the new process," ISO-NE said.

When FERC issued Order 2023 last July, the potential capacity of projects waiting in interconnection queues exceeded 2 TW, more than the amount of generation already online nationwide. It seeks to streamline the interconnection process for transmission providers, provide greater timing and cost certainty to interconnection customers and prevent discrimination against the wave of renewables being proposed nationwide. (See *FERC Updates Interconnection Queue Process with Order 2023*.) ■

ISO-NE News

ISO-NE CLG Highlights Importance of Demand Response

By Jon Lamson

Speakers at the ISO-NE Consumer Liaison Group (CLG) meeting March 6 stressed the importance of proactive efforts to unlock the potential of demand response and peak shifting, as electrification is projected to double New England's peak loads in coming decades.

The CLG met in Portland for its first quarterly meeting of 2024 and featured discussions on the benefits of widescale load shifting, along with the barriers that prevent the realization of those benefits.

Andrew Landry, deputy public advocate for Maine, called demand response "an important tool that we need to take advantage of to the maximum extent."

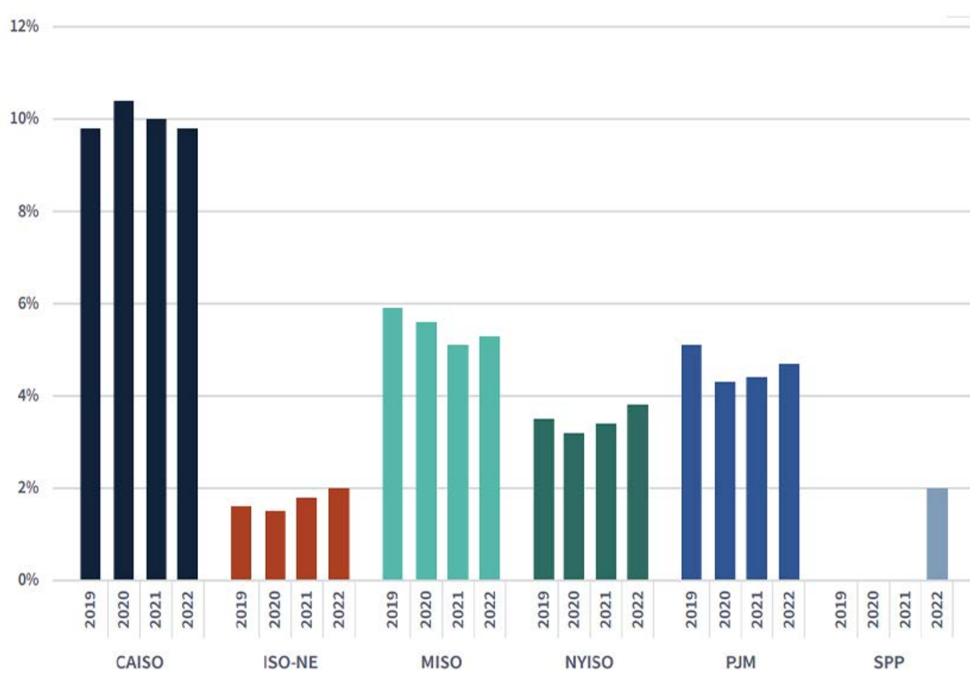
Landry cited ISO-NE's projection of a 57-GW peak load in 2050, as well as the RTO's finding that limiting this peak to 51 GW would save about $9 billion in avoided transmission upgrades.

"If we can find ways to reduce the demand, even with the amount of electrification that's going on, it would reduce the need for transmission," Landry said.

He highlighted FERC data showing demand response makes up a significantly lower percent of total installed capacity for ISO-NE compared to CAISO, MISO, NYISO and PJM.

Eric Johnson of ISO-NE echoed the importance of reducing demand but added that "there's a lot of infrastructure challenges that need to be resolved." He noted that the FERC data does not include the region's significant energy efficiency gains. (*Report: Many US Utilities not Delivering on Energy Efficiency*.)

Jill Powers of CAISO presented to the CLG about load-shifting efforts in California, where demand response surpasses all other RTOs by percent of installed capacity. Powers said demand response programs have helped the state avoid rolling blackouts during grid stress events and emphasized the role of both in-market and out-of-market mechanisms to engage a wide range of customers.



Demand response as a percentage of total installed capacity | *FERC*

"It's not just at the wholesale level that we need to be collaborating" to unlock demand flexibility, Power said.

She outlined two out-of-market programs in California that incentivize demand reductions during peak hours: the Demand Side Grid Support Program and the Emergency Load Reduction Program. The programs are not administered by CAISO, but they do respond to real-time and day-ahead signals from CAISO.

"We believe that demand can provide responses similar to a flexible resource, helping to balance the grid," she said.

The CLG also featured a panel of New England stakeholders, who focused on the role of ISO-NE in increasing demand response efforts within the region.

Doug Hurley, vice president of policy at Icetec Energy Services, stressed that peak demand reductions from one electricity customer on the grid provides benefits to all customers by reducing the clearing price, limiting emissions associated with peaker plants, and ultimately reducing the need for new transmission investments.

Hurley said the region needs to align state demand programs and retail rate design with optimal times to charge and discharge batteries — such as at night or midday when cheap solar power is available — to better balance load and reduce emissions.

He also called out ISO-NE's compliance proposal for Order 2222 as a "missed opportunity" to increase the participation of flexible demand resources in its markets, saying the "compliance to date will not achieve any participation." (See *FERC Accepts ISO-NE Order 2222 Compliance Filing*.)

Ian Burnes of Efficiency Maine Trust agreed with Hurley's criticism of ISO-NE's Order 2222 compliance and called on ISO-NE to help ease the barriers for small resources to participate as demand response resources.

"We have a lot of work to do here," Burnes said. "It's very, very difficult to aggregate lots of small assets and have them participate."

Burnes added that significant investments in physical infrastructure to enable residential customers to receive and respond to incentives to shift their demand will be necessary.

"I do not want to trivialize that investment — it is going to be hard," Burnes said. "I think that needs to be our focus." ■

GCPA MISO-SPP Forum

FERC's Christie Warns of 'Very Dark Place'

Commissioner Again Cautions Against Loss of Baseload Generation

By Tom Kleckner

FERC Commissioner Mark Christie shares his thoughts on the need for dispatchable resources to Gulf Coast Power Association attendees. | *© RTO Insider LLC*

NEW ORLEANS — FERC Commissioner Mark Christie brought his message of grid reliability to the Crescent City on March 4, near the site of what he says is the best college football atmosphere in the country: LSU's Tiger Stadium at night.

"When the sun goes down, that Tiger Stadium is a rocking environment," Christie said. Hands down, he said, it beats the atmosphere at Alabama, Michigan, Notre Dame, Southern California and Texas.

Dispensing with pleasantries, Christie tended to the business at hand with his keynote address to the Gulf Coast Power Association's MISO-SPP Forum.

"In America, we're heading for a very dark place. We're heading, as Franklin Roosevelt said, to a rendezvous with destiny," he said. "Well, we're heading, in terms of the reliability of our power grid, for a rendezvous with reality. And you can't escape reality because ultimately, reality will track you down. And reality is tracking us down and we need an honest conversation about why we're heading for a reliability crisis."

Christie has been making the rounds with his warning that dark times — figuratively and literally — lie ahead for the nation.

Last May, he told the U.S. Senate's Energy and Natural Resources (ENR) Committee that the grid is facing "potentially catastrophic consequences." During an SPP forum on resource adequacy in September, he ran through a list of capacity shortfalls that grid operators are expecting and explained his use of the adjective "catastrophic." ("Multiple-day outages [are] ... catastrophic by any definition.") (See *Senators Praise Phillips, FERC's Output at Oversight Hearing*, *Nation's Grid Faces 'Rendezvous with Reality'*.)

"It's arithmetic. We are subtracting dispatchable resources at a pace that's not sustainable, and we can't build dispatchable resources to replace the dispatchable resources we're shutting down," he said.

Christie said the problem is not necessarily the massive additions of intermittent wind and solar resources in many parts of the country, but rather the pace of thermal resources' retirement.

"We're pushing [dispatchable resources] off the grid far too quickly for any replacement resources to take up the slack," he said. "That's why we're heading for crisis. Its simple subtraction."

He bolstered his case by linking George Orwell and Vladimir Lenin to fellow revolutionaries MISO's John Bear and NERC's Jim Robb.

Bear and Robb?

"If you've ever met John Bear, he doesn't look like a revolutionary. If you've ever met Jim Robb, he doesn't look like a revolutionary," Christie said. Referencing a quote often attributed to Orwell — "In a time of deceit, telling the truth is a revolutionary act." He said the two CEOs are performing revolutionary acts.

"Because why? Because they're telling the truth," Christie explained. "They're telling the truth, that we are forcing dispatchable resources off the grid at a pace that simply is unsustainable, and it is going to affect our reliability."

Robb told the Senate ENR Committee in June that the grid's increasing reliance on renewable resources as baseline resources retire will likely lead to "more frequent and more serious disruptions." In MISO's latest *Reliability Imperative report* released in February, Bear called for facing "some hard realities" because of "immediate and serious challenges" to the region's grid reliability. (See *Robb Warns of 'Serious Disruptions' from Grid Transition*, *MISO Publishes Call to Action to Bypass Danger in Reliability Imperative Report*.)

"What to do? Well, this didn't come from Lenin, but it comes from where I grew up in West Virginia," Christie said. "It's called the first rule of holes, and the first rule of holes is when you're in one, stop digging. So, if we're digging a hole deeper because we're shutting down dispatchable resources at a pace we can't sustain, let's stop doing it."

Christie's remarks were received positively by several regulators in the audience.

Andrew French, chair of the Kansas Corporation Commission with a background in environmental science, said he couldn't disagree with anything Christie said.

"I'm an environmentalist. I come from a perspective of wanting to transition as much clean energy onto the grid as we can," French

Continued on page 30

GCPA MISO-SPP Forum

Overheard at 10th Annual GCPA MISO-SPP Forum

Conference Revolves Around Generation Fleet's Transition

By Amanda Durish Cook and Tom Kleckner

NEW ORLEANS — After being forced to turn away attendees from 2023's Gulf Coast Power Association MISO-SPP Forum, the association set up shop this year in a name-brand hotel near the French Quarter. All the better to welcome more than 330 attendees, a record, for discussions that focused primarily on the energy transition.

"Here we are in a real hotel," said R Street Institute's Beth Garza, chair of the GCPA board, in kicking off the March 4-5 conference.

During a friendly opening chat between MISO's and SPP's CEOs, Barbara Sugg said maintaining resource adequacy and addressing "massive" load growth during the transition comprises the nucleus of RTO operations today.

Sugg said she sympathized with SPP members having to make decisions about resource retirements while also facing potential capacity deficits. SPP needs to ensure it has "enough of the right resources," Sugg said, noting adequate future reliability attributes "are just not there yet" in generation lining up for the grid today versus what's retiring.

Panel discussion before record attendance for the GCPA MISO-SPP Forum. | © *RTO Insider LLC*

"For us, it's all about the energy transition," MISO CEO John Bear said, adding that MISO has a good feel for what its members hope to accomplish over the next 15 years.

He said MISO is preoccupied with transmission planning, a market redesign and completing a market platform upgrade to handle a great deal more variability. MISO is also working on a complete redesign of control room operations, he added.

SPP CEO Barbara Sugg and MISO CEO John Bear share a laugh. | © *RTO Insider LLC*

"Besides that, we're not very busy," Bear joked.

Bear said before, MISO operations were a "simple exercise," with MISO carrying enough reserves to get the footprint through a predictable afternoon peak. Today, Bear said, MISO must secure many more types of operating reserves to handle weather conditions that "vary significantly by day."

"We've got to watch closely new technology, but it's still out there" in the distance, Bear reminded attendees. He said though new technologies are promising, they're not yet developed enough to be able to take over for scores of retiring baseload generation resources. He emphasized that MISO needs to maintain a fleet of dispatchable generation resources to supplement weather-dependent resources.

However, Bear said he's optimistic about the potential for iron-air battery storage, once an unwieldly and forgotten technology of the 1970s. He said MISO is set to add three 5- to 15-MW iron-air batteries in the coming years.

LSEs Describe Tough Situation

Mike Wise, senior vice president of regulatory

GCPA MISO-SPP Forum

and market strategy at Golden Spread Electric Cooperative, said load-serving entities are in a "real challenging environment." He said the fleet transition for LSEs is like a bad version of an '80s beer commercial. He said instead of the "more taste, less filling" slogan conveying two competing positives, LSEs face a "more cost, less reliable" reality with only disadvantages.

Wise blasted SPP's recent FERC filing hiking its planning reserve margin requirement from 12% to 15%. Golden Spread, American Electric Power, Xcel Energy and several cooperatives have protested the proposal in a joint filing. Wise said SPP simply cannot dictate a planning reserve margin 25% higher than six months ago. He said the RTO and market participants need to slow the transition down so "we don't destroy" today's system.

"You're putting loads between a rock and a hard place: ... can't find it, can't build it. What are you going to do?" he asked rhetorically. "These are unmanageable numbers."

Wise said new natural gas combustion turbines are the most attractive choice for affordable and reliable power that earns a consistent capacity credit.

"We're forced into making 30- to 40-year decisions very quickly," 1803 Electric Cooperative COO Ron Repsher said of resource planning. Despite the obstacles, he said the relatively new cooperative will continue to pursue self-built generation and not rely solely on power purchase agreements with independent power producers.

Repsher said while it's true that 1803 customers want environmentally friendly power when they are polled, they also indicate they're unwilling to shoulder more costs to implement it.

"What that really means is they want reliability. First and foremost," he said.

Entergy Director of System Planning Samrat Datta said the transition is complicated by resource adequacy risks, large load additions, and ever-evolving rules from RTOs and federal agencies. He said Entergy intends to meet its sustainability goals "because our customers want it."

Jim Dauphinais, an attorney representing multiple industrial customers in MISO, said customers not only are concerned over a large-scale reliability failure, but RTO market rules "moving very quickly." He said the costs of market rule changes "trickle down very quickly" to customers and he said they're concerned about an overinvestment in grid facilities.

"We can get ahead of the game and build facilities that are neither used nor useful," Dauphinais said. "We can make progress toward clean energy, but we have to do it in a way that's economical."

ERCOT's Jeff Billo (left) and SPP's C.J. Brown | *© RTO Insider LLC*

Monitors Emphasize Importance of Pricing

Keith Collins, SPP's vice president of market monitoring, said standby generation is undoubtedly undervalued and called for the industry to improve the quality of green energy.

"It's one thing to have the four-hour battery. It's another thing to have a four-day battery," he said. "We need resources to be available."

But "the market cannot get what is not valued," Collins said, adding that premiums should be placed on attributes that promote flexibility, availability, resiliency and dependability.

"A gas resource that's more secure should have more accreditation," he said.

Carrie Milton of Potomac Economics, MISO's Independent Market Monitor, said the RTO's markets are "well structured" to reliably handle the clean energy transformation. MISO intends to pivot to a marginal, availability-based capacity accreditation and recently proposed to up its value of lost load from $3,500/MWh to $10,000/MWh.

Milton said the grid operator's markets would benefit from longer-lease reserve product to handle uncertainties that arise over two to four hours and a look-ahead dispatch that anticipates instructions an hour ahead of time, rather than during five-minute intervals.

Although some "tweaks" will be needed along the way, Milton said, the MISO markets send strong price signals when generation is necessary.

"The nice thing about shortage pricing ... is that every generator in that moment is going to try to get on the system," she said.

But Collins said when neighboring RTOs choose different reserve pricing setups and values of lost load, those differences can complicate or even dissuade some power exports.

"That's something of real concern that as different markets choose different designs, that can affect imports and interchanges," he said.

State-of-the-art Opportunities

"You're hearing about the doom and gloom we're facing over the next five to 10 years. We're here to talk about the solutions," Southern Renewable Energy Association Executive Director Simon Mahan said in opening a panel on how hydrogen, offshore wind, carbon capture and small modular nuclear reactors can assuage a reliability crisis.

He asked panelists what makes them optimistic about their burgeoning technologies.

GCPA MISO-SPP Forum

"We're going through the 'hype cycle' for clean hydrogen," Center for Houston's Future CEO Brett Perlman said, citing 35 potential hydrogen projects in development around the Gulf of Mexico.

"It's a testament to the developer-friendly mentality we have in Texas and Louisiana," Perlman said. He said he thinks hydrogen is on the cusp of greater adoption and likened it to the atmosphere in Texas 20 years ago, when the state began adding wind and solar resources at a record rate.

Perlman also said tax incentives that put early hydrogen projects on equal footing with other generation builds are vital. Anthony Bodin, development director for RWE's Gulf of Mexico offshore wind project, said the developer *secured* a federal lease last year to develop an up-to-2-GW offshore wind farm about 40 miles off the Louisiana coast. However, the "GoMex" project isn't expected to be commercially operational until the mid-2030s.

"It's going to take time, so we have to be patient," Bodin said. "The potential for offshore wind is massive."

Michael Curtis, Dow's carbon and energy technology principal, said he's hopeful the company's *development* of a small modular reactor at its Seadrift Operations manufacturing site in Texas by 2030 will create a blueprint for other similar projects at industrial sites.

"Being first, there are a lot of eyes on us … Maybe in 15 years, we'll see more of these projects actually up and running," Curtis said. However, he added, a beleaguered enriched uranium supply chain presents obstacles to developing SMRs.

"Instead of giving out millions of dollars with an 'M,' we're giving out billions of dollars with a 'B,' and that's a real shift," said Maria Duaime Robinson, director of the Department of Energy's Grid Deployment Office.

Duaime Robinson said the department recently distributed about $7 billion and will hand out more than that in the coming years. She said despite some perceptions, DOE is making its investments in a "thoughtful fashion and not just throwing money at the problem."

Durham McCormick, a partner at McGuire Woods, said the monetary awards contained in the Inflation Reduction Act don't operate under a carrot-and-stick mentality. Instead, he said the IRA's tax credits and grants are equivalent to smacking the industry with a "giant carrot."

McCormick said new types of resources must come online for the U.S. to meet the Paris Climate Accord's emissions goals. He said he foresees more renewable curtailment and increased battery storage over the next decades to keep generation and load lined up.

SPP Market Monitoring Unit's Keith Collins and Potomac Economics' Carrie Milton | © *RTO Insider LLC*

Bob Gee, Gee Strategies Group | © *RTO Insider LLC*

Electric-gas Harmonization not Rocket Science

Bob Gee, co-chair of the 2022 Gas-Electric Harmonization Forum for the North American Energy Standards Board, called for more transparency into gas pipelines and "more timely collection" of granular information regarding their operational status.

Perhaps because his keynote address came during the first day's last session, the former Texas Public Utility Commission chair chose hot dog vendors as his analogy.

"A certain degree of transparency is required when your business serves the public, whether you are an electric or gas utility or a hot dog seller," Gee said. "But today, we have more transparency in how Nathan's makes hot dogs and what goes into them than we do on certain intrastate pipelines, such as available capacity. This is significant because if I don't like Nathan's hot dogs, I can buy one from another hot dog maker. In the intrastate pipeline industry, there is no Oscar Mayer pipeline."

Gee, former FERC Chair Pat Wood and Sue Tierney, DOE's assistant secretary for policy under President Bill Clinton, spent more than a year working to produce their report at the request of FERC and NERC. "*Houston, We Have a Problem*" laid out 20 recommendations to improve coordination between the electric and gas sectors, although five revealed "widely divergent opinions" between the industries.

A separate FERC-NERC report on the December 2022 winter storm said gas-supply failures have contributed to three of the five most recent power outages since 2011. (See *FERC-NERC Elliott Report Calls Winter Outages 'Unacceptable'*.)

"Despite this increasing interdependence

GCPA MISO-SPP Forum

between our natural gas and electric power delivery systems, we have yet to significantly overhaul the way these two industries interact and rely upon one another, and thus remain at risk," Gee said.

He said the gas-electric system has its weaknesses because the gas infrastructure originally was designed to supply local distribution companies, not to serve power markets. "Over the last 20 years, this interdependence has doubled. But with that interdependence, our needs for attention and responsiveness have increased," Gee said.

"We ignore the long-term consequences of this dynamic relationship at our peril."

The forum report's title is a reference to the historic 1970 Apollo 13 mission. "Houston, we have a problem," were astronaut Jack Swigert's words back to Mission Control after an oxygen tank ruptured and disabled the spacecraft's electrical and life-support systems. The crew relied on the lunar module's backup systems to return safely.

"NASA dusted itself off, fixed its quality-control systems, and successfully completed four more manned lunar missions in the succeeding two years," Gee said. "Unlike Apollo 13, harmonizing the gas-electric divide isn't rocket science. We can do this."

Just Transition for the Disadvantaged

Sanya Carley, co-director of the Kleinman Center for Energy Policy at the University of Pennsylvania, delivered a sobering reminder that many in the U.S. cope with overwhelming poverty and are overlooked in the energy transition.

Carley said U.S. utilities carried out about 2.62 million disconnections in 2022, according to *utilitydisconnections.org*. She said disconnections disproportionately affected households of color, households with children under age 5, households that rely on medical equipment or households with homes in disrepair.

According to information from the U.S. Energy Information Administration, one in three households reports difficulty affording energy bills while keeping their homes at comfortable temperatures. One in three households also struggles to pay bills.

Sanya Carley, University of Pennsylvania | *© RTO Insider LLC*

New low-carbon technologies are adopted predominantly by wealthy and white households. The associated financial tax incentives

Evergy's Kayla Messamore (right) listens to comments from Invenergy's Nicole Luckey. | *© RTO Insider LLC*

GCPA MISO-SPP Forum

flow disproportionally to them, Carley said, arguing for a reassessment of subsidies.

"Energy systems have always created winners and losers and this energy transition will be no different unless there are deliberate and coordinated efforts otherwise," she said.

Carley said she has visited communities that were "very heavily rooted" in coal production, calling them "mono-economies." She described coal companies going under and "completely removing" an entire town's tax base and leading to cascading effects where breadwinners lose salaries and no longer can afford to dine out, leading to a "degradation of the entire economy."

Carley said she's spoken to community members who reported feelings of grief, bitterness and being used by the nation when coal was king. She said during 2020 and 2021, autoworkers told her they were being deceived about the electric vehicle boom. They said the EVs they were building were unaffordable and lacked adequate charging infrastructure once they were on the road, Carley said.

Nevertheless, she said, the workers felt they've earned the right to build the next generation of automobiles, having given their youth and oftentimes health to build gas-powered vehicles.

"Inequities in the energy system are inevitable, yet avoidable with deliberate action," Carley argued.

Evaluating FERC Order 2023

"The era of flat demand is over!" declared Chelsea Howard Robben, an executive director of regional origination for NextEra Energy, during a panel discussion on FERC Order 2023 and its incorporation by grid operators.

Referring to the never-ending hunger for energy by the oil and gas sector and electrification, Robben said, "This is an exciting time for our industry. As we see these demand growth opportunities, let's capitalize on it."

Order 2023 is designed to do just that. It requires transmission providers to study projects in clusters, penalizes those that don't complete the studies on time and adds requirements discouraging speculative projects to unclog jammed interconnection queues. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

"I know both SPP and MISO have stated goals to shrink that process to a 12-month process, but we still have interconnection queues that are five and seven years old," Robben said.

FERC special counsel Kim Smaczniak said transmission planning must be forward-looking rather than reactive, saying the future is going to look very different from the past.

"When we see the pace of retirements and the volume of generation that is seeking to interconnect, ensuring that that new capacity can come online quickly and safely is essential to ensure the reliable, affordable grid," she said. "Doing a better job of looking ahead to understand the future supply and demand conditions is, in my view, a no-brainer. We need to ensure transmission investments float infrastructure that will make the grid more reliable and resilient."

"Having a well-functioning interconnection queue means we can get through it quickly. We know what our upgrade costs are going to be. It's incredibly important to my company," said Nicole Luckey, senior vice president of regulatory affairs for Invenergy. "We were really pleased with Order 2023. I think there are little tweaks here and there that we've certainly raised, but we think implementing cluster-based studies across the U.S. is going to make for a more efficient interconnection process."

Kayla Messamore, vice president of strategy and long-term planning for Evergy, said her company has some concerns with the order's penalty structure. Were SPP to pay a penalty for missing a deadline, she said, its nonprofit status would mean the members would end up covering the costs.

"So that's the main concern. … But in general, I think it's great," she said. "We have 4,000 MW of renewables that just Evergy is trying to add over the next 15 years. So, we have a lot of reasons to want the queue to move more quickly and to avoid future backlogs." ■

FERC's Christie Warns of 'Very Dark Place'

Commissioner Again Cautions Against Loss of Baseload Generation

Continued from page 25

told *RTO Insider*. "But, also, as a state regulator that is obviously concerned about both cost and absolutely reliability, I can't really disagree with anything.

"As Commissioner Christie has said before, it's not the addition of [renewable] resources that's the problem. It's the subtraction of the attributes associated with some of the traditional resources that is the issue. That is the issue we have to solve," he added.

Marcus Hawkins, executive director of the Organization of MISO States and jaded by years of projected shortfalls that failed to materialize, shared a more nuanced perspective of Christie's comments.

"In MISO-land, we have a 'boy who cried wolf' problem" with projected shortfalls, he said. Hawkins noted OMS surveys over the past decade of the RTO's members have consistently found shortfalls three or four years out.

"It's different this time. There's load growth that's complicating this. You need context. You can't just go and say, "Eight gigawatts short in 2028,' because that's been the story since 2015," he said.

Hawkins said he agreed with Christie's comments that MISO states with vertically integrated utilities give regulators a lot of power to address reliability issues.

"That's what we've seen these last 10 years. We've had the gaps projected and you see the regulators work with their utilities and fill that gap," he said. "I think we're in a great position to continue to do that and MISO is providing more useful information to the regulators to make decisions, and that's helpful."

Christie urged those listening to repeat the actions taken by Bear and others sounding the alarm on energy shortfalls.

"You have got to be brutally honest with your state regulators, your federal regulators and policymakers about the direction that we're heading in and the rendezvous with reality that we're facing," he said. "If our power supply doesn't keep up with load, it goes out. That's not an engineering marvel. That's just the way it works." ■

MISO News

Conservation Groups File Another Lawsuit to Stop Cardinal-Hickory Creek's Last Mile

By Amanda Durish Cook

The Cardinal-Hickory Creek line under construction | *ATC and ITC Midwest*

Three conservation groups have filed a new civil suit against three federal agencies for consenting to permits and a land exchange that allow the divisive Cardinal-Hickory Creek 345-kV line to carve a final, mile-long path through a protected wildlife refuge in Wisconsin.

The Environmental Law and Policy Center filed the *complaint* in the U.S. District Court for the Western District of Wisconsin on behalf of the Driftless Area Land Conservancy, Wisconsin Wildlife Federation and National Wildlife Refuge Association.

The three allege the U.S. Fish and Wildlife Service, U.S. Rural Utilities Service and U.S. Army Corps of Engineers violated the National Environmental Protection Act (NEPA), National Wildlife Refuge System Improvement Act of 1997 and Administrative Procedure Act by approving permits and allowing a land exchange to assemble the final mile-long stretch of the 102-mile, $650-million transmission line through the Upper Mississippi River National Wildlife and Fish Refuge.

Co-owners ITC Midwest and Dairyland Power Cooperative late last month finalized an *agreement* with the Fish and Wildlife Service to turn over about 36 acres of privately owned land along the Mississippi River in Wisconsin for refuge annexation while receiving about 20 existing acres of the refuge near the Iowa state border.

The conservation groups accused federal agencies of "skewing the required NEPA review and purpose and need statements to avoid rigorously exploring and objectively evaluating all reasonable alternatives." They also said the east-west 200-foot transmission towers will interrupt a "major north-south migratory bird flyway used by hundreds of thousands of birds annually."

"The transmission companies did not evaluate alternative crossings outside of the refuge in their environmental impact statement, and we should not set a precedent that a simple land swap is all it takes to plow through a national treasure," Driftless Area Land Conservancy Executive Director Jennifer Filipiak said in a press release.

Wisconsin Wildlife Federation President Kevyn Quamme said a "massive transmission line crossing through this area will be harmful to the important habitats for fish and wildlife in the refuge and to the millions of migrating birds that pass through on the Mississippi Flyway each year."

"Building a transmission line through the refuge also will serve as a deterrent to locals and tourists alike who visit the refuge and contribute to the local economy," Quamme added.

Cardinal-Hickory Creek is the final piece of MISO's 17 Multi-Value Projects approved as a $5 billion portfolio in 2011. The line is estimated to facilitate the connection of nearly 20 GW of renewable energy and has been mired in litigation for more than a decade.

The newest lawsuit concerning Cardinal-Hickory Creek is related to a federal district court decision issued in 2022 that halted construction on the final line segment, finding that federal agencies violated federal law when they cleared the line to route through the refuge. (See *Federal Judge: Tx Line Can't Cross Wildlife Refuge*.) Last summer, the Seventh Circuit U.S. Court of Appeals vacated the decision and lifted the injunction, finding that the Fish and Wildlife Service at the time hadn't issued a final permit for the utilities to build across the refuge.

The Driftless Area Land Conservancy, Wisconsin Wildlife Federation and National Wildlife Refuge Association said Cardinal-Hickory Creek's developers were warned in the 2022 ruling against them that stringing lines right up to the protected wildlife refuge would be staging an "orchestrated train wreck."

'Weaponizing NEPA'

Co-owners ITC Midwest and Dairyland Power Cooperative said they were "dismayed" by the latest litigation and said the lawsuit could counterintuitively "delay significant environmental benefits" to the Upper Mississippi River National Wildlife and Fish Refuge.

The two said the deed exchange stands to expand the refuge when the line is completed. They said an *analysis* from the Fish and Wildlife Service found that "the proposed land exchange fulfills the refuge's purposes by exchanging lower-quality habitat for higher-quality habitat, increasing the total protected acreage in the refuge, reducing habitat fragmentation in the long term and allowing the refuge to acquire a high-priority tract that would not otherwise be available." The Fish and Wildlife Service also said that in the long

MISO News

run, the land swap will supplement the refuge's breeding grounds.

ITC and Dairyland said the refuge land they want to use to cross the Mississippi River is adjacent to a road and farmland and has "low habitat value." They also said construction of Cardinal-Hickory Creek would allow them to deenergize and remove an existing 161-kV line that cuts through the refuge. The Fish and Wildlife Service deemed that a net conservation benefit because it also would increase the protected acreage and cut down on the number of transmission towers in the refuge overall.

ITC and Dairyland said they're committed to minimizing impacts to grass habitats, scrub and wetlands, and they pledged to not grade land inside the refuge. They said they're offering to nearly double the refuge's land tradeoff for a transmission project that is "vital to the future of our region's renewable energy and clean energy economy."

"As of October 2023, there are 161 renewable generation projects in Wisconsin, Iowa and other Upper Midwestern states representing more than 24.7 GW dependent upon its completion — enough to power millions of homes and businesses with clean energy," the two said.

The companies also said the continued litigation over Cardinal-Hickory Creek is delaying its in-service date and driving up costs. They accused the conservation groups of "weaponizing NEPA" and said the Environmental Law and Policy Center should be in favor of the line because it supports a clean energy economy.

"Over the past few years, several of these same opponents have filed multiple lawsuits in federal and state court trying to stop construction of the project. The co-owner utilities have successfully navigated four separate injunctions and won appeals before the Wisconsin Supreme Court, as well as three different favorable opinions from the U.S. Seventh Circuit Court of Appeals," ITC and Dairyland said.

They referenced a county circuit court judge's decision last year to uphold the Wisconsin Public Service Commission's 2019 decision to issue a certificate of public convenience and necessity for the line, as well as a 2022 ruling from the Wisconsin Supreme Court that a former state regulator's years' worth of encrypted messages to the line developers' employees did not amount to a serious risk of bias during permitting. (See *Wisconsin Tx Project Clears State Litigation*; *Wisconsin Court Undercuts Lawsuit in Cardinal-Hickory Creek Dispute*.)

Co-owners ATC, ITC Midwest and Dairyland Power Cooperative report that Cardinal-Hickory Creek is more than 95% complete. The eastern half of the line was placed into service in early December.

ITC Midwest said it expects construction on the western half of the project from the Hickory Creek Substation in Dubuque County, Iowa, to the Hill Valley Substation in Wisconsin to be finished and the line in service by June. ITC said the segment is virtually complete except for a 2.2-mile stretch extending from a spot near the Nelson Dewey Substation in the village of Cassville, Wis., westward across the Mississippi River to a spot near the Turkey River Substation in Clayton County, Iowa. That portion of the line includes the route through the refuge. ■

MISO News

MISO Lodges 2nd Complaint Against SPP over Disputed Crypto Load on M2M Flowgate

By Amanda Durish Cook

MISO has registered a separate complaint with FERC to retract market-to-market coordination with SPP on a contentious flowgate persistently taxed by a North Dakota cryptocurrency mining operation.

MISO said it wants refunds for its members and for FERC to end what it calls "improper M2M coordination activities" on the 230-kV Charlie Creek flowgate because it cannot offer meaningful congestion relief (*EL24-85*). The grid operator sought fast-tracked treatment and said its complaint should dovetail with an initial complaint submitted by Montana-Dakota Utilities Co. (See *Crypto Load on MISO-SPP M2M Constraint Draws Complaint from Montana-Dakota Utilities*.)

MISO repeated concerns made in the original complaint that the flowgate, which serves the 200-MW Atlas Power Data Center, has cost its members more than $38 million in "unnecessary, unjust and unreasonable M2M charges." (See *SPP, MISO Clash over Crypto-strained M2M Flowgate*.)

MISO said SPP is violating their M2M coordination procedures under the RTOs' joint operating agreement by refusing to lift the line's M2M status. It said the flowgate is being used to "address local congestion issues in a load pocket located in [SPP] … where MISO has no regional flows and is unable to relieve congestion due to the lack of generation." MISO asked for refunds for M2M charges associated with the flowgate from April 1, 2023, onward.

Additionally, MISO asked FERC to pronounce it and SPP's current M2M coordination termination process unreasonable and discriminatory because MISO doesn't have recourse to revoke congestion management even when it's unhelpful, leaving its members on the hook for millions. MISO also said it didn't have faith that it and SPP could revise the provisions in their interregional coordination process without FERC guidance.

"This finding will ensure that the dispute that led to this complaint does not occur again and is promptly remedied, as both MISO and SPP appear to agree that changes are needed while disagreeing on how those changes should be implemented. MISO will work with SPP to develop appropriate revisions, but MISO does not believe that even a mutually collaborative effort, without the benefit of such a threshold FERC finding, providing a firm timeline and prescribed compliance process, would be effective or expeditious," MISO wrote.

MISO said M2M coordination on Charlie Creek should have ended as soon as the Atlas Power Data Center began operating early last year.

MISO said neither it nor SPP have adequate generation to relieve the constraints "exacerbated" by the cryptocurrency facility situated in the Williston Load Pocket (WLP). It also said it and SPP have no "economic" M2M coordination available to them, with SPP acknowledging in a 2021 transmission planning report that the "root" of the issue lies in "the lack of transmission to accommodate the level of transfers required to serve the forecasted load in the future, contributing to a weak system unable to maintain acceptable voltage levels."

"In fact, congestion in the WLP stems primarily from a local reliability issue and the best solution is to build additional transmission," MISO argued, saying the "obvious ineffectiveness" of the M2M coordination should be clear to FERC.

SPP has asked FERC to deny Montana-Dakota Utilities' complaint, maintaining that the M2M activation and congestion coordination is permitted according to the joint operating agreement. It has said it and MISO are working through the disagreement, though MISO has said negotiations are at an impasse, which effectively works as SPP blocking any hope for an M2M cancellation. ■

Transmission construction near the Charlie Creek flowgate area | *Western Area Power Administration*

MISO News

MISO Estimates 2023 Member Savings Near $5B

By Amanda Durish Cook

MISO announced last week that it saved its membership roughly $5 billion in 2023 by providing a resource sharing pool for utilities.

Most of the estimated $3.9 billion to $5.8 billion in savings is derived from MISO members having to maintain fewer grid assets to meet peak demand versus operating as isolated utilities; it includes MISO's management of shared capacity, demand response and economical renewable generation dispatch.

MISO said 2023 savings also stem from more efficient use of members' existing grid assets through its energy and ancillary service markets, its reliable system management and its FERC and NERC compliance activities on behalf of members.

MISO estimates the value it provides annually and publishes it under its *Value Proposition*.

The RTO said its total benefit-to-cost ratio was 15:1 last year, up from 12:1 in 2022. Last year, MISO said it saved members $4 billion in 2022. (See *MISO Says 2022 Value Proposition Tops $4B*.)

MISO said despite inflation, it expects the value of its markets and planning efficiencies to rise in coming years because it will help members navigate a "hypercomplex" system dotted with more intermittent energy sources. By 2030, MISO said single-year benefits could conservatively range between $4.3 billion and $5.8 billion and by 2040, they could nearly triple to between $11.6 billion and $14.3 billion.

"Although costs may continue to increase due to the current environment, MISO expects these costs to remain a small fraction of the benefits provided now and in the future," MISO said, pointing out that it holds its cost of membership at or below inflation.

MISO estimates that since 2007, it has saved members more than $45 billion. The grid operator said the annual benefits it delivers have increased significantly from about $600 million in 2007.

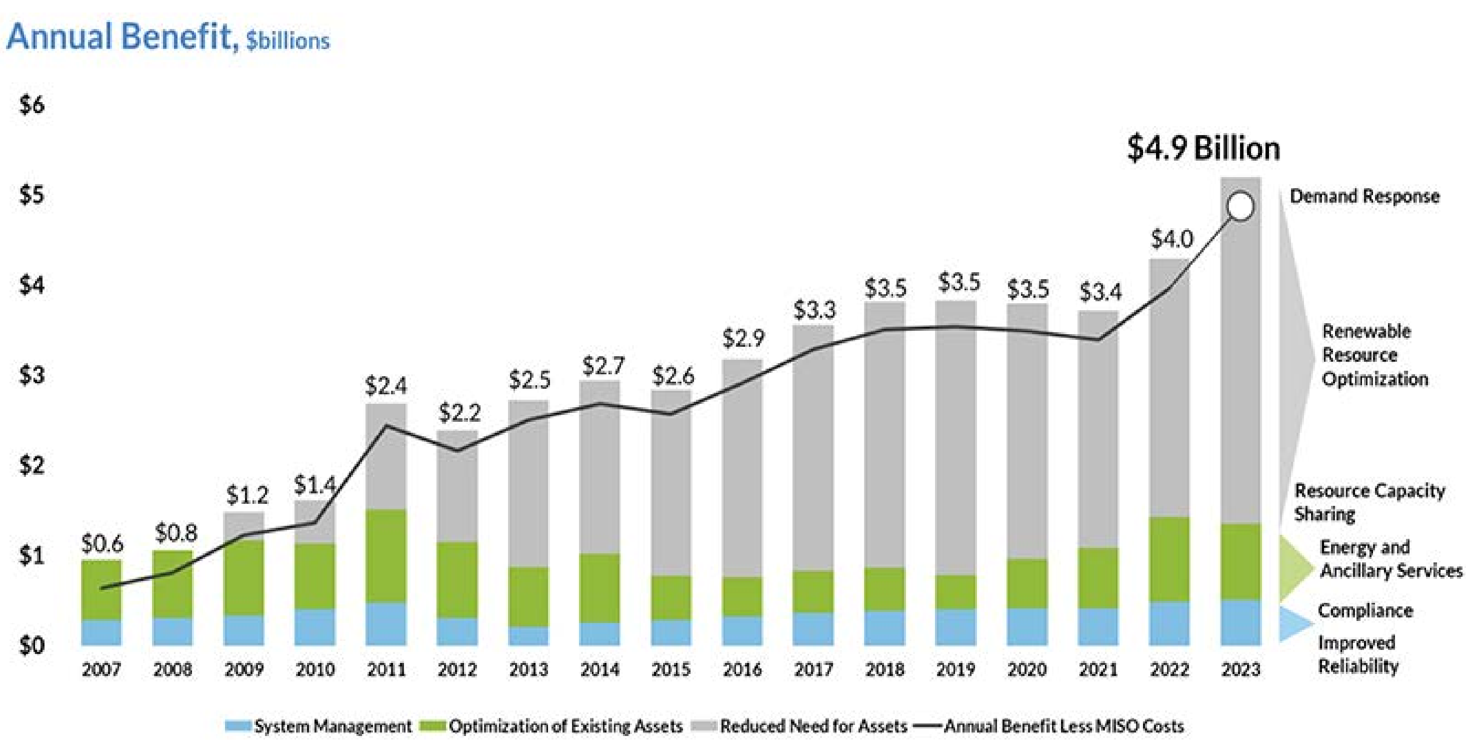
MISO said the more substantial savings this year can be attributed to its members' resource capacity sharing at anywhere from $2.5 billion to $4.1 billion; savings achieved through the RTO's energy and ancillary service markets at $795 million to $878 million; and integrating renewable energy into planning at $402 million to $472 million.

MISO's newest value proposition comes as multiple organizations are voicing concerns that consumers aren't realizing the full potential of possible benefits in MISO South.

Center-right think tank R Street Institute last week *said* MISO South has a pattern of safeguarding its transmission constraints, resulting in utility-owned power plants that are insulated from competition with lower-cost resources.

MISO South suffers from "overcapitalizing self-built generation and transmission … the opposite of what regional markets are supposed to accomplish," R Street said.

Renewables watchdog organization Energy and Policy Institute has voiced similar concerns. Both have cited a *working paper* from the National Bureau of Economic Research, concluding that a more integrated MISO South grid would have dropped Entergy Arkansas' and Entergy Louisiana's net revenues by a combined $930 million in 2022. ■



MISO 2007-2023 Value Proposition estimates | *MISO*

PJM News

PJM OC Briefs

By Devin Leith-Yessian

PJM Presents Monthly Operating Statistics, Low Spin Response

VALLEY FORGE, Pa. — PJM's Stephanie Schwarz *presented* the RTO's monthly operating statistics, which showed an average hourly forecast error of 1.26% for February and an hourly peak error just over 3% over forecast on Feb. 3.

The month saw three shared reserve events, one spin event and three post-contingency local load relief warnings.

During the Feb. 24 spin event, which lasted about 12 minutes, Schwarz said 36% of the 2,689 MW spin response assignment for generation materialized as well as 7% of the 262 MW assignment for demand response. The total penalty for the event was 1,967 MW out of a 2,951 MW spin assignment. Generation without a spin assignment increased by 1,777 MW during the event.

The Reserve Certainty Senior Task Force (RCSTF) is considering changes to the reserve penalty rate for resources that fail to perform. Stakeholders in the OC argued that the response from generation without a reserve commitment shows there's capability for intramarket resources to move on dispatch.

PJM's Glen Boyle said the underperformance Feb. 24 was concentrated in a few units and overall figures would have looked much better if those resources met their obligations. In response to questions about how reserve assignments interact with the basepoints resources are expected to follow, Boyle said assignments are not included in basepoints; however, the RCSTF is considering ways of aligning the two so that reserve resources can follow dispatch and provide reserves at the same time.

PJM Preparing Forecast for April Solar Eclipse

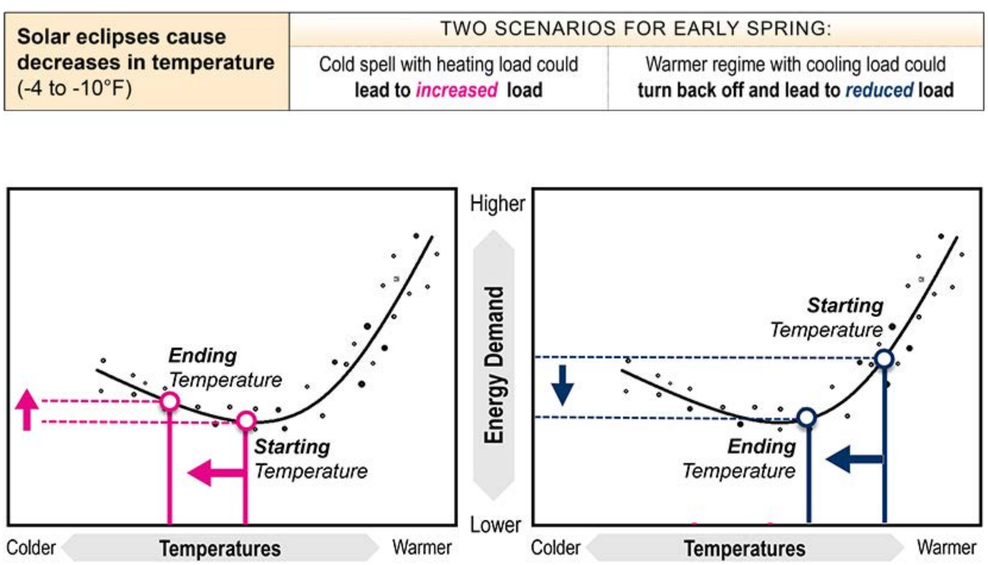
Pre-eclipse solar generation could decline by as much as 85% during the solar eclipse expected on April 8 and diminished temperatures during the event could result in varying outcomes for demand, PJM's Michael Stewart *presented* to the OC.

Grid-connected solar generation could decrease by 1.8-6.7 GW based on cloud coverage, while the decrease in behind-the-meter solar could elevate net load by 4.8 GW on a sunny day or 2.2 GW under overcast conditions. Consumer behavior could also change load patterns, but the impact shouldn't be as significant as that seen on holidays, Stewart said.

PJM's Joe Mulhern said more generation may be needed to compensate for decreased solar output, particularly on a cooler day. Eclipses tend to cause temperatures to drop by between 4 and 10 degrees, which could increase load on a colder day as heating load increases, or decrease load on a hot day as air conditioning switches off. The tipping point tends to be between 55 and 65 degrees, depending on the region, Mulhern and Stewart told *RTO Insider*.

PJM Dispatch Manager Donnie Bielak said operators will be looking at best- and worse-case scenarios and will refine the actions that may be employed in the days leading up to the eclipse.

A similar relationship between diminished solar output and lower air conditioning load was reported during the wildfire smoke that blanketed the Northeast during summer 2023. (See *RTOs Report Diminished Solar Output, Loads as Wildfire Smoke Passes*.)



A PJM graphic shows the possible impact to load should the solar eclipse expected on April 8 cause a decrease in temperatures. | *PJM*

Periodic Review Manual Revisions Endorsed

Stakeholders endorsed revisions to Manual 12: Balancing Operations and Manual 37: Reliability Coordination through the documents' periodic review.

The *changes* to Manual 12 align language and diagrams with portions of Manual 11 pertaining to real-time market operations and bilateral transactions and added detail to the economic minimum and emergency minimum parameters requirements for hybrid resources.

The *revisions* to Manual 37 reflect updated NERC standards around establishing and communicating system operating limits, such as thermal ratings and voltage or stability limits.

PJM Provides Security Update

PJM's Jim Gluck *said* cybersecurity professionals are recommending individuals restart their internet routers and install security software updates to mitigate the risk that they could be exploited by the hacking group Volt Typhoon, which was the topic of a cybersecurity *advisory* issued by the Cybersecurity and Infrastructure Security Agency last month.

He also encouraged members to ensure that their data is secured both on internal networks and through any external parties they work with. He highlighted a data breach exposing a security vulnerability at a Canadian nuclear operator caused by an employee of a third party with access to the company's data. ■

PJM MIC Briefs

Stakeholders Endorse PJM Energy Efficiency Proposal

VALLEY FORGE, Pa. — The Market Implementation Committee voted March 6 to endorse a PJM *proposal* to revise its approach to measuring and verifying the capacity provided by energy efficiency resources. (See *PJM Seeking Expedited Approval of Energy Efficiency Changes*.)

PJM's Pete Langbein said the proposal aims to clarify which baseline EE providers should use to measure the savings a resource can offer into a Base Residual Auction (BRA); require that they demonstrate to PJM that installations of the more efficient equipment was completed; and show they have exclusive rights with the owner of the equipment to enter its savings into the capacity market.

The PJM proposal received 52% support, winning out over packages sponsored by *CPower* and *Affirmed Energy*, which respectively received 26% and 4% support. The question of whether stakeholders preferred the PJM proposal over the status quo originally tied, but multiple stakeholders cited challenges casting their ballots. The committee opted to reconsider the item, and support for the package grew to 61%.

The changes are being brought under an expedited process with the aim of receiving stakeholder approval in time to implement for the 2025/26 BRA, scheduled for July. Redlines were first presented at the Feb. 22 Markets and Reliability Committee, where several stakeholders argued that the proposal is moving too quickly to ensure that it's understood by market participants and fully vetted to prevent unintended consequences.

The proposal would draw a sharper distinction between the standard baseline — which considers the last efficient equipment that could be installed versus the product being installed as an EE resource — and the current load baseline — which requires there be a cause-and-effect link between the revenues EE resources receive through the capacity market and their participation in the BRA. If a resource is eligible to use the current load baseline, the proposal would set a three-year limit on technical reference manuals (TRMs) to measure the load of the new equipment against; if no TRMs were available, EE providers would be required to use meter data.

Independent Market Monitor Joe Bowring said PJM's proposal does not go as far as he would like in tightening EE standards but that it would nonetheless improve market functionality. As he often does, Bowring noted that EE is not a resource in PJM's capacity market and argued that it should not be paid through the capacity market.

Affirmed's Luke Fishback and CPower's Ken Schisler raised issues they said would prevent EE providers from complying with the proposal. They argued that the three-year limit on TRMs would disqualify the majority of those produced by PJM states. Their companies had offered longer windows in their own packages.

Langbein told *RTO Insider* that older TRMs may include equipment that is no longer representative of what is being installed in that region, possibly leading to an inflated baseline.

Bowring said a five-year TRM may include data

| *Shutterstock*

PJM News

from at least three years prior to the TRM date and that the eight-year-old results are then used to estimate savings for four years into the future. The baselines even for a three-year-old TRM are not relevant to any actual savings, he argued.

Schisler said PJM's language requiring a causal link between capacity market participation and the revenues it offers comes from an understandable desire to ensure that capacity revenues are producing a reduction in load. But he argued the proposal is too strict and would exclude projects from participating in the market if they have multiple benefits, including capacity revenues. At the February MRC meeting, he gave the example of a project to improve home insulation that would reduce climate control load while also alleviating health issues from building materials exposed to humid air.

Bowring said the fact that EE providers assert that there does not need to be a link between the wholesale PJM capacity market and the assumed savings for which customers pay $100 million per year demonstrates why EE should not be paid through the capacity market. He argued that the market is not intended as a vehicle to subsidize broader social goals.

Fishback said Affirmed's proposal was aimed at taking a more data-driven approach to the question of how often TRMs are updated and would have included updates to PJM's attestation requirements, the way they verify installations and how they verify unique ownership of capacity rights. He said PJM's language would likely prove especially onerous incentivizing adoption of efficient products through retailers.

"This language as written in the redline runs the risk of taking the vast majority of utility programs and removing them from the table, because the majority of them are run through retailers and retailers will not be able to get an address for each lightbulb they sold," he said.

Fishback also argued that the changes are being made too quickly without any apparent need ahead of the next auction. He motioned to defer the vote to the April MIC meeting, arguing that the three proposals were similar in many ways and more time could allow for a compromise to be found. The motion failed with 57% in opposition.

1st Read of Proposal on Capacity Obligations Resulting from Large Load Additions

Dominion Energy and American Electric Power presented a joint *proposal* to accurately assign the capacity obligations from large load additions (LLAs) to entities within a transmission zone, including entities operating under fixed resource requirement (FRR) and Reliability Pricing Model (RPM) rules. (See "Capacity Obligations for Forecasted Large Load Adjustments," *PJM MIC Briefs: Oct. 4, 2023*.)

When bringing the issue charge, AEP's Josh Burkholder argued that the data center growth can lead to the obligation to procure capacity to serve that load being split between market participants in a transmission zone even when the load falls entirely within one's footprint.

In February, FERC granted AEP a waiver of the capacity obligation for four of its vertically integrated utilities to not include about 1,860 MW of data center load expected in AEP Ohio (*ER24-545*). The waiver is applicable for only the 2025/26 auction; in its filing, AEP noted that a stakeholder process had been initiated to consider changes to how capacity obligations for large load additions are calculated. (See *FERC Grants AEP Utilities Waiver of Capacity Obligation*.)

Dominion has submitted a similar waiver request, though Old Dominion Electric Cooperative (ODEC) and Northern Virginia Electric Cooperative (NOVEC) have protested, arguing that the circumstances around the Data Center Alley in Northern Virginia differ from those AEP faced in Ohio (*ER24-1037*).

The proposal would exclude LLAs from the calculation of base zonal scaling factors and apply that load to the obligation peak load (OPL) of the zone it is projected to be added to. LLAs are determined by PJM using information from load-serving entities about expected load growth and detailed in the RTO's annual load forecast reports under Table B-9.

Much of the discussion centered around how PJM uses the hourly load forecasts provided by LSEs to determine the LLAs it enters into Table B-9.

ODEC's Mike Cocco said that because the transmission provider will be assigning LLA directly to transmission-dependent utilities, this shifting of incentives and associated costs will necessitate the ability for the TDUs to provide their own LLA forecast to the Load Analysis Subcommittee. In addition, he could understand the arguments as to why the proposal should not be voted on without language detailing how PJM approves the LLAs, suggesting there should be some documented process PJM follows that should be established in the manuals.

Dominion's Jim Davis and MIC Facilitator Foluso Afelumo said changes to the development of Table B-9 are out of the scope of the issue charge approved in October.

Rory Sweeney of NOVEC argued that because that process is not laid out in the manuals, it would not constitute a change to existing practices and therefore is within the issue charge's scope.

Bowring said the proposal needs to have explicit rules governing the treatment of changes in the load forecast for large loads. The final amount of capacity paid for is a result of a final forecast just prior to the delivery year that can vary significantly from the forecast in the proposal. The final forecast also defines the level of capacity transfer rights, the capacity market equivalent of financial transmission rights.

Other Committee Business

The MIC endorsed a PJM quick-fix *proposal* seeking to outline its existing practices around interface pricing points, which groups buses together when calculating LMPs for energy transfers between external areas. The revisions to Manual 11 include a definition of interface pricing points and establish an annual review of power flow impacts on each interface and a recommendation from the Monitor to adjust the weighting of component interfaces to maintain congruity between prices and system conditions.

PJM also presented a joint *proposal* with the Monitor to add more details to the parameters that synchronized condensers include in their market offers. PJM's David Hauske said the proposal is focused on adding Operating Agreement and manual definitions of condense startup costs, condense-to-generate costs and condense energy use; there would be no change to PJM practices, he said.

There will be some overlap between the 2025/26 BRA and the initiation of pre-auction activities for the following auction, Langbein told the committee. Pre-auction activity deadlines that will fall before the conclusion of the 2025/26 auction include: the deadline for planned resources to notify PJM of their notice of intent, minimum offer price rule certification, requests for an exception from the must-offer requirement, the Monitor's posting of unit-specific energy and ancillary services (EAS) offset, and seller requests for winter capacity interconnection rights. Langbein said PJM is not currently considering any delay to the 2026/27 BRA, which is *scheduled* to open in December. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Long-term Regional Transmission Planning Proposal

VALLEY FORGE, Pa. — The Planning Committee endorsed PJM's long-term regional transmission planning (LTRTP) *proposal* during its March 5 meeting, advancing manual revisions that would expand the RTO's planning horizon to 15 years. (See "PJM Presents Long-term Planning Proposal," *PJM PC/TEAC Briefs: Jan. 9, 2024*.)

The changes are centered around two base cases focused on reliability needs eight and 15 years out; two policy scenarios looking at new entry backed by state legislation eight to 15 years in advance; and an additional policy scenario including higher generation entry not backed by signed legislation. The two-year planning cycle would be extended to three years because of the increased number of scenarios. The proposal was endorsed by the PC with 66% support, setting it on a path to undergo a first read at the Markets and Reliability Committee on March 20 with an endorsement vote possible April 25.

Thermal and voltage analyses would be performed on the eight-year base scenario, replacing the existing 10-year model for voltage analysis, and would then inform the five-year Regional Transmission Expansion Plan (RTEP) near-term process. Thermal and voltage analysis would also be performed on the 15-year scenario.

PJM's Michael Herman said staff continue to view the RTEP process as focused on ensuring reliability through a holistic approach, and the new process would enhance the existing rounds of analysis by considering the impacts of a wider range of generation scenarios. He said there is potential for the policy scenarios to influence the scope of projects that PJM recommends be added to the RTEP, though more stakeholder discussions are needed to flesh out the process.

"This is something PJM will have to continue to evaluate and discuss with stakeholders … but the way that PJM envisions this [is that] we can't be performing the reliability base case in a silo," he said.

PJM Vice President of Planning Paul McGlynn gave the example of the reliability scenarios recommending the construction of a new line and the policy scenarios suggesting designing the line with a higher voltage. He said the policy analysis could also lead to PJM preferring expandable solutions.

Paul McGlynn, PJM | © *RTO Insider LLC*

PJM's Jonathan Kern said the distinction between the reliability and policy scenarios would allow the RTO to continue to follow cost-causation principles, adding that the planning process would first identify projects needed for reliability; anything needed to support assumptions beyond that would be allocated as State Agreement Approach projects.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the proposal doesn't follow market principles and would grant the RTO a power akin to developing its own integrated resource plans. He also argued that the quick-fix stakeholder process used to develop the proposal hasn't allow for adequate stakeholder analysis of the impact the proposal could have. The quick-fix process allows for an *issue charge* to be brought concurrent with a proposed solution.

"This is PJM having too much discretion about investments in our assets, whether they're existing or potentially new," he said.

Stakeholders also questioned whether PJM has the authority to implement the changes through manuals revisions alone, arguing that revisions to the governing documents and FERC filings are necessary.

Transmission Expansion Advisory Committee

PJM Updates RTEP and Market Efficiency Window Schedule

PJM is *planning* to open a 30-day RTEP window March 12 as part of the 2023 RTEP to address growing data center load in Columbus, Ohio, which is part of the AEP transmission zone.

PJM's Wenzheng Qiu told the Transmission Expansion Advisory Committee that there are also thermal violations identified in the PSEG zone around its Hinchmans substation and that the 500-kV Fentress-Yadkin line in the Dominion zone is nearing end of life.

The window is shorter than the typical RTEP process because of the immediate-need nature of the violations. Qiu said the earliest PJM is likely to do a first read on projects it may recommend from the window is June.

The RTO has completed the base case assumptions for the 2024/25 market efficiency cycle and is planning to open a competitive window in January 2025 to address congestion on several lines, PJM's Nick Dumitriu *told* the committee. He said much of the new congestion identified since the previous base case is driven by changes in the load forecast, changing market conditions and the RTEP upgrades approved by the Board of Managers.

Supplemental Needs and Project Proposals

FirstEnergy *presented* a project to replace two 230/46-kV transformers at its Yeagertown substation in the Penelec transmission zone because of their age and increased risk of failure. The cost to replace both is estimated to be about $7.5 million. Completion of the project is expected by Oct. 17, 2025.

Also in the Penelec zone, the utility said there is a need to replace three segments of its 345-kV transmission corridor between the Erie West and Armstrong substations. The line was constructed more than 50 years ago and is experiencing deterioration of wooden H-frame structures. Sections of the corridor, which intersects with the Handsome Lake and Wayne substations, have experienced multiple unplanned outages since 2015.

FirstEnergy also *presented* a proposal to replace three 500/138-kV transformers at its Cabot substation in the APS zone for $24.6 million. The transformers are nearing their end of life and seeing elevated maintenance issues. The transformers would be replaced on a staggered timeline, with the first installation slated to be completed by Dec. 31, 2027, and the third by June 30, 2028. ■

— Devin Leith-Yessian

Southeast

Tenn. Congressmen Introduce Bill to Make TVA IRP Process More Public

By Amanda Durish Cook

Two members of Congress from Tennessee have come across the aisle and introduced a bill that would force the Tennessee Valley Authority to make its integrated resource planning process more transparent.

Reps. Steve Cohen (D) and Tim Burchett (R) added another "IRP" acronym to TVA's lexicon when they introduced the *TVA Increase Rate of Participation Act* on March 8.

The proposed legislation would compel TVA to establish an Office of Public Participation to oversee outreach and make recommendations to the utility to improve public accessibility and accountability.

The representatives said their plan would "ensure the most efficient, affordable, environmentally conscious and reliable plan for meeting customers' energy needs."

The office would be tasked with making sure TVA's IRP contains more detailed information like forecasted peak demand and sales data; planned transmission investments; sensitivity analyses on fuel costs, environmental regulations, electrification and distributed energy resources; disclosure of modeling assumptions to intervening parties; and descriptions of public influence on the plan.

Additionally, the office would be responsible for making sure the TVA Board of Directors makes decisions "approving, denying or modifying the plan, like every other utility regulator, according to the least cost and reliability requirements in the Energy Policy Act of 1992, and require consideration of resilience, extreme weather risk and public health impacts."

"Transparency is critical in making public policy and, for too long, TVA's decision-making has been obscure and opaque, such as their current IRP process where organizations had to be hand-selected to participate in their working group," Cohen, a longtime critic of TVA "secrecy," said in a press release. "TVA needs outside guidance to meet the changing needs of utility customers as it addresses resiliency and other foreseeable disruptions to its planning,"

Cohen made a similar statement Jan. 25 during "The People's Voice on TVA's Energy Plan" *public hearing* in Nashville that was hosted by Appalachian Voices, the Center for Biological Diversity, Southern Renewable Energy Association, Energy Alabama, Southern Alliance for Clean Energy and the Sierra Club, among others. The hearing focused on the shortcomings and shadowy nature of TVA's IRP process and was held after the utility didn't respond to requests to host a public hearing on its IRP. (See *Nonprofits Attempt to Force a More Transparent TVA IRP Process*.)

Burchett said TVA's customers "deserve the chance to gain insight into TVA's decision-m aking process and the opportunity to offer input."

"I appreciate the ways TVA has made an effort to become more transparent in recent years, and this would provide some solid guidelines on how to make that even more of a reality," he said.

TVA is conducting its first long-term IRP effort since 2019. The plan not only will guide near-term resource decisions, but steer long-term programs that will determine how the region's electricity needs will be met through 2050.

TVA: More Public Engagement to Come

TVA spokesperson Scott Fiedler characterized the federal agency as a "transparent organization that actively seeks public input on and about our decision-making processes." He said TVA "intentionally seeks out, engages and welcomes a diverse set of voices" in its IRP process.

"We are currently reviewing the legislation that was introduced today. We believe we have good methodology, but TVA is always open to improving our public input processes," Fiedler said in an emailed statement to *RTO Insider*.

TVA said it will release a draft IRP later in March for public comment. From there, the utility has committed to holding two virtual open houses on the IRP in addition to a series of in-person open houses in Tennessee, Alabama, Mississippi, Kentucky, Georgia, North Carolina and Virginia.

"This will help ensure that every member of the public will be able to receive information and ask questions and provide feedback," Fiedler said. "Moving forward, with public stakeholders, TVA is creating a roadmap that will support TVA's mission of making life better for everyone in the region."

TVA kicked off its IRP process last spring and said it began the planning by soliciting public input on considerations for the 2024 IRP. The IRP is evaluated by a nonpublic, invitation-only working group TVA formed, composed of representatives of "local power companies, academic institutions, environmental organizations, state government and other community groups," according to TVA. The working group reviews the federal utility's inputs, assumptions and results; TVA posts short summaries of the working group's meetings to its IRP *site*.

Nonprofits Say Law is Overdue

Several environmental and advocacy groups applauded the legislation's introduction.

Vote Solar Southeast Regulatory Director Jake Duncan called the TVA Increase Rate of Participation Act "a long-overdue yet monumental stride toward creating a meaningful, transparent and inclusive energy plan for the TVA."

"We applaud Congressman Cohen and Congressman Burchett for their leadership in ensuring TVA's power system planning includes the very people these decisions impact," Appalachian Voices' Bri Knisley said.

Sierra Club Tennessee Field Organizing Strategist Amy Kelly said TVA has operated for too long without "meaningful public and expert engagement during their energy planning."

"TVA was founded as a public utility to enrich and benefit the people, industries and environment of the Tennessee Valley, and this legislation would help TVA live up to its mission," she said.

The Southern Alliance for Clean Energy (SACE) also has criticized TVA for carrying out "one of the least public IRP processes in the nation" despite being the nation's sole federally owned utility.

"This emboldens TVA to invest in new fossil fuel infrastructure, which will expose people in the Tennessee Valley to the risks associated with higher bills, more carbon pollution and more power outages in the future," SACE said in a statement February.

By all appearances, TVA 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*.)

SACE has criticized TVA for using the minimum required public engagement outlined in the National Environmental Policy Act as a substitute for comprehensive public interaction. ■

SPP News

FERC Finds SPP Partly Complies with Order 2222

SPP's latest attempt to comply with *FERC Order 2222* has resulted in the commission's partial acceptance and a directive to make another compliance filing.

FERC on March 1 ordered the RTO to submit its filing by April 30 and to update the commission on implementation timeline milestones associated with the target effective date in the third quarter of 2025 (*ER22-1697*).

The commission found several areas of concern with SPP's proposed tariff revisions to comply with Order 2222's requirements removing barriers so distributed energy resource (DERs) aggregations can participate in RTOs' and ISOs' capacity, energy and ancillary service markets:

- compensation for demand response in heterogeneous aggregations.
- attestation requirements for aggregators.
- clarity around interconnection requirements.
- the potential for double-counting services.


SPP has reached partial compliance with FERC's Order 2222. | *DOE*

Responding to the Missouri Public Service Commission's request for more stakeholder engagement on the part of SPP, FERC urged the grid operator to work with distribution utilities, relevant electric retail regulatory authorities and other stakeholders to ensure its implementation process complements any state-level changes to comply with Order 2222.

"We encourage SPP to explore use of a stakeholder group to promote transparency, and in particular, to share information about progress on the major software and process changes to core SPP systems necessary for implementation," the commissioners wrote.

SPP made its first compliance filing in May 2022. That August, FERC staff issued a data request advising SPP that more information was necessary to process the filing. SPP filed its response in October.

The proceeding has drawn more than three dozen intervenors. ■

— Tom Kleckner

Company Briefs

US Banks Abandon 'Bare Minimum' Environmental Standards Project

Four of the world's biggest banks — Citi, Bank of America, JPMorgan Chase and Wells Fargo — have left the Equator Principles, a set of minimum industry standards and safeguards for financial institutions addressing environmental and social risks in countries where they finance fossil fuel and mining projects.

The Equator Principles have been around for more than 20 years. While not enforceable, they provide a framework of environmental standards that banks agreed would underpin financing deals on pollution-causing extractive projects.

Spokespeople for the four banks all said they would continue to be informed by those principles, but their names have been removed from the list.

More: *The Guardian*; *Reuters*

Rivian Pauses Construction of $5B Georgia Electric Truck Plant

Electric Vehicle maker Rivian on March 7 announced that it is pausing construction of its $5 billion manufacturing plant in Georgia to speed production and save money.

Rivian planned to start building its new R2 midsize SUVs at the Georgia site, but CEO RJ Scaringe said production of the R2 will instead begin at its existing plant in Normal, Ill. He said the move would allow Rivian to produce the R2 more quickly and save $2.25 billion in capital spending.

The company did not give a timetable for restarting work on the Georgia plant, saying, "The timing for resuming construction is expected to be later."

More: *The Associated Press*

SRP Board Approves More Ambitious Sustainability Goals

The SRP Board of Directors last week approved revisions to its 2035 Sustainability Goals establishing more ambitious targets to reduce carbon emissions, increase energy efficiency and electrification, conserve water and improve forest health.

The goals include, among others, reducing the amount of CO_2 emitted from generation by 82% from 2005 levels by 2035 and achieving net-zero carbon by 2050, as well as supporting adoption of 1 million EVs in SRP's service territory and managing 90% of EV charging by 2035.

Originally approved in 2019, the goals are updated every five years.

More: *SRP*

Federal Briefs

25 States Join GOP Lawsuits Challenging New EPA Soot Rule

Twenty-five Republican-led states and a host of business groups filed lawsuits March 6 challenging EPA's new rule setting tougher soot pollution standards.

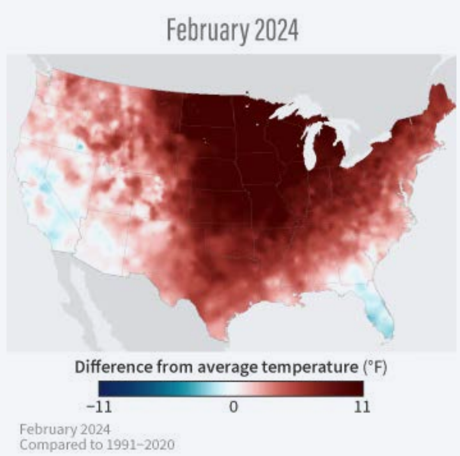
Twenty-four states filed a joint challenge stating the rule would raise costs for manufacturers, utilities and families and could block new manufacturing plants and infrastructure. Texas filed a separate suit, as did business groups led by the U.S. Chamber of Commerce and National Association of Manufacturers.

The EPA rule sets maximum levels of fine particle pollution at 9 micrograms per cubic meter of air, down from 12 micrograms as established under the Obama administration.

More: *The Associated Press*

US Records Hottest Winter on Record

The lower 48 states experienced their warmest winter on record this year, according to new National Oceanic and Atmospheric Administration data.



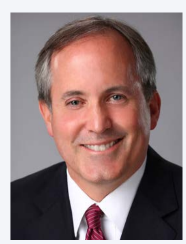
For the country, the meteorological winter (December, January and February) had an average temperature 5.4 degrees F above average for the season, beating out the winter of 2015-2016. Meanwhile, parts of the Upper Midwest had temperature anomalies more than 10 degrees above the 20th century average.

The average temperature across the U.S. in February was 41.1 F, 7.2 degrees above the 20th-century average and ranking as the third-warmest February in NOAA's 130-year climate record.

More: *NOAA*

Texas Sues EPA over Finalized Methane Rule

The state of Texas last week sued the Biden administration over an EPA rule restricting methane emissions.



A lawsuit was requested in late January by the Texas Railroad Commission while the rule was still being finalized. In a request to Attorney General **Ken Paxton**, the commission asked for legal action on the rule. The commission called the rule "extremely unreasonable, and time-consuming, given that there have been vast improvements with reduced methane emissions in the state."

EPA estimates the rule could cut up to 58 million tons of methane emissions by 2038.

More: *The Hill*

State Briefs

IOWA

Summit Wants to Add 340 Pipeline Miles

Summit Carbon Solutions plans to expand its statewide carbon dioxide pipeline footprint by about 50% (about 340 miles) to connect to more ethanol plants, according to filings with the Utilities Board.

The company is awaiting approval of its initial proposal from the board to lay the backbone of its pipeline system. That plan includes about 690 miles of pipe that would connect to a dozen ethanol plants, transporting their captured carbon dioxide to North Dakota for underground storage.

Summit's project was initially rejected in the Dakotas, but North Dakota is reconsidering, and the company plans to reapply in South Dakota.

More: *Iowa Capital Dispatch*

KENTUCKY

Senate Committee Advances Bill to Create Energy Needs Commission

The Senate Natural Resources and Energy Committee on March 6 advanced a bill forming a commission to assess statewide electric generation capabilities and energy demands.

The Energy Planning and Inventory Commission's role would include reviewing state utilities' plans to retire power plants, and its findings and recommendations would be submitted to the state Public Service Commission. Its 18 members would mostly be appointed by the governor and confirmed by the Senate.

The proposal now goes to the full Senate and would still need House approval.

More: *The Associated Press*

LOUISIANA

Entergy Proposes Floating Natural Gas Station

Entergy on March 8 filed a request with the Public Service Commission for the approval of the Bayou Power Station, a $411 million, 112-MW floating natural gas power station.

Situated atop a barge across from a substation in Leeville, the power station would help support surrounding areas through a microgrid. The project includes the construction of Bayou Power Station, expansion of the Leeville substation and transmission connections.

More: *Power Engineering International*

MAINE

CMP Seeks $162M Storm Recovery Reimbursement

Central Maine Power on March 4 asked the Public Utilities Commission to approve $162 million in recovery costs following multiple major storms last year.

CMP spokesperson Jon Breed said storm recovery costs would be paid for by rate increases.

More: *Maine Public Radio*

MINNESOTA

PUC Approves Great River Plan for 90% Carbon-free Power by 2035

The Public Utilities Commission on March 7 approved Great River Energy's plan to sell 90% carbon-free electricity by 2035.

At the heart of Great River's plan is its relationship with Coal Creek Station, which it sold in 2022 to Rainbow Energy Center. Before the deal, Great River planned to close the plant. Instead, it struck a deal to buy from Rainbow much of the power Coal Creek produces. Still, Great River plans to follow existing contracts that slash the amount of power it buys from Rainbow over time until its agreements expire in 2031. The approved plan would replace the power with energy from wind farms, and by adding battery storage and solar plants.

More: *Star Tribune*

NORTH DAKOTA

PSC Approves New Tx Lines

The Public Service Commission on March 5 approved two high-voltage power line projects for Basin Electric Power Cooperative that it says will help alleviate power congestion in northwest North Dakota and the Bakken region.

The shorter line is a nearly 15-mile, 345-kV line in Williams County. The other would be a 32.5-mile line in Dunn and McKenzie Counties. The total cost is $105 million.

Basin plans to start work on the lines this spring.

More: *Prairie Public Broadcasting*

OREGON

Legislature Passes Bill to Rid Public Retirement System of Coal Investments

The state Senate on March 5 passed a bill directing the state Treasury to divest the Public Employee Retirement System of nearly $1 billion in coal mining and energy investments.

The bill passed the Senate in a 16-13 party-line vote after a partisan vote in the House in February. The proposal would direct the Treasury to "try to ensure" the state's $94 billion Public Employee Retirement System does not hold stock in companies that derive 20% or more of their revenue from coal production. It also would direct the Treasury to limit new investments in such companies.

The bill heads to Gov. Tina Kotek (D).

More: *Oregon Capital Chronicle*

PacifiCorp Ordered to Pay Wildfire Victims Additional $42M

A jury on March 5 ordered PacifiCorp to pay more than $42 million to 10 victims of wildfires on Labor Day 2020.

Last June, a jury found PacifiCorp liable for negligently failing to cut power to customers despite warnings from top fire officials. The jury determined the company should have to pay punitive and other damages — a decision that applied to a group including the owners of up to 2,500 properties. The latest decision was the third verdict applying last year's ruling to a specific set of plaintiffs.

PacifiCorp is appealing.

More: *The Associated Press*

RHODE ISLAND

Providence City Council Aims for Carbon-neutral City Buildings by 2040

The Providence City Council on March 7

passed a law requiring municipal buildings to be carbon-neutral by 2040.

The ordinance, sponsored by 10 of the body's 15 members, encourages energy efficiency and urges that buildings be equipped with "electric heating and cooling systems, electric hot water heating, 100% renewable energy consumption, maximum on-site renewable energy production, thermal energy networks, and biofuel or battery-electric emergency backup facilities."

More: *The Providence Journal*

State Sees Rise in GHG Emissions from Power Plants

According to EPA data, emissions from the state's major natural gas power plants increased by more than a million short tons last year.

Four out of five reporting facilities saw emission increases between 52 and 72%, as the five plants produced about 3 million tons of greenhouse emissions in 2022 and about 4 million tons in 2023.

State officials say the retirements of other New England power plants often result in ISO-NE asking more of Rhode Island's natural gas plants.

More: *ecoRI*

TEXAS

Xcel Energy Says Equipment May Have Started Smokehouse Creek Fire

Xcel Energy on March 7 acknowledged that its power equipment may have caused the Smokehouse Creek fire in the Texas Panhandle, the largest in state history.

"Based on currently available information, Xcel Energy acknowledges that its facilities appear to have been involved in an ignition of the Smokehouse Creek fire," the company said in a statement.

Xcel said it is cooperating with investigations into the blaze. It also disputed allegations it was negligent in maintaining and operating its equipment.

More: *The Washington Post*

VIRGINIA

Assembly Passes Bills to Charge Customers for SMRs

Bills that would allow Dominion Energy and Appalachian Power to seek approval to charge customers for the costs of developing small modular nuclear reactors won final approval in the House of Delegates and Senate and are now headed to Gov. Glenn Youngkin (R).

Floor amendments made by the House to Sen. David Marsden's (D) bill were approved by the Senate in a 26-14 vote. Originally, Marsden's bill applied to both Dominion Energy and Appalachian Power, but Appalachian was removed because HB 1491, a similar bill introduced by Del. Israel O'Quinn (R) that passed both chambers in February, covers Appalachian.

All approved costs would be recovered through a rate adjustment clause amortized over the greater of the period when costs were incurred or five years.

More: *Cardinal News*

Charlotte County Approves Solar Projects

The Charlotte County Board of Supervisors

on Feb. 14 approved two solar projects.

The board voted 6-1 to approve the Charlotte Solar 2 Austin Goldman project and 5-2 to approve the Charlotte Solar 1 Gibson project.

More: *The Charlotte Gazette*

Halifax County Halts Applications for New Solar Projects

The Halifax County Board of Supervisors on March 4 voted 7-1 to put a halt on solar project applications.

Election District 1 Supervisor Pete Riddle made the motion to table any conditional-use permit applications for solar projects "until we figure this out."

Prior to the supervisors' vote, several residents spoke out against future solar development in the community.

More: *The Gazette-Virginian*