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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Corrections

The subtitle for the article *Texas PUC Rejects SWEPCO Application for Renewables at Pirkey* in last week's newsletter incorrectly stated that Kathleen Jackson "joined" the commission. Jackson has been serving on the commission since August 2022, having been appointed by Gov. Greg Abbott. The text of the article correctly reported that her appointment was confirmed by the Texas Senate.

In the article *Report: Storage Projects Stymied at Distribution System Interconnection* in last week's newsletter, Avangrid's flexible interconnection pilot allowed the 15-MW Spencerport solar project to avoid extra costs for interconnection, but the project was not moved up in the queue, as reported.

FERC/Federal News

Lawmakers, White House Promise More Work on Permitting After Debt Deal

But Both Sides of Aisle Unsure of What that will Entail

By K Kaufmann

Even before the Senate on Thursday passed the Fiscal Responsibility Act (*H.R. 3746*) — the bipartisan deal to lift the U.S. debt ceiling that also included provisions related to energy infrastructure permitting — lawmakers on both sides of the aisle were talking about the work still ahead to truly streamline and accelerate the process and construction.

Signed by President Joe Biden *on Saturday*, the new law sets time and page limits on environmental reviews under the National Environmental Policy Act (NEPA) and calls for designation of a single federal agency to lead reviews and issue the final environmental evaluation, provisions that already had general bipartisan support. It also expands the use of "categorical exclusions" exempting projects from NEPA evaluations but does little to advance the buildout of vitally needed interregional transmission, a top Democratic and industry priority. (See *Debt Ceiling Bill Provides 'Mini-deal' on Permitting*.)

"As it sits right now, I feel like we just lost two years," Rep. Sean Casten (D-Ill.), co-chair of the House Sustainable Energy and Environment Coalition, told *E&E News* on Wednesday.

While crediting Biden for getting the deal done and averting a potentially disastrous U.S. default, Casten said White House negotiators "totally messed up the transmission piece, and they didn't deal with us on the level about what they had. And so, we didn't know how bad they botched it until after we saw the text."

Casten was referring to the FRA's call for a study on the need for transmission to support interregional transfers of power for grid resilience and reliability, which NERC and FERC now have two and a half years to complete.

"There is absolutely no good reason why anybody needs to spend two years studying a problem that has been asked and answered 15 times," Casten told E&E after his attempt to amend the bill was killed in the House Rules Committee.

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Casten was one of several lawmakers quoted in post-deal analyses of the next moves, if any, on "permitting reform," as the issue is commonly referred to.

On the Republican side, Sen. Kevin Cramer (R-N.D.) saw the permitting issue going "one of two ways."

"One way might be to check the box — 'We did this' — and then never think about it again," Cramer said, according to *The Hill*. "The other possibility would be that we create a little bit of momentum and say, 'OK, now let's get serious and drill down a little bit.' I hope it's the latter."

Similarly, Sen. Shelley Moore Capito (R-W.Va.), ranking member of the Senate Environment and Public Works (EPW) Committee, described the FRA as a "jumping point to start off again in our bipartisan talks," The Hill reported. Her particular target is "judicial reform": cutting down the six-year time frame now allowed for legal challenges to NEPA reviews, which the FRA did not include.

Industry trade groups also urged Congress to move ahead with more comprehensive initiatives on permitting and transmission.

Christina Hayes, executive director of Americans for a Clean Energy Grid, said her organization "believes that setting timelines for federal environmental reviews is a helpful first step but is only the beginning. While we do not believe that an interregional transmission study is needed, we hope that it can be completed quickly, building on efforts already underway at FERC, to ensure buildout of the transmission we need to keep the lights on."

The American Clean Power Association seconded the motion. "ACP is appreciative of the steps taken to include much-needed reforms to improve efficiency of the permitting process for clean energy projects," said CEO Jason Grumet. But "it's critical that Congress build upon these initial steps and tackle comprehensive, meaningful reform to improve our nation's clean power transmission capabilities and bring about the clean energy future America needs."

BIG WIRES Nixed

A drive for bipartisan permitting legislation had been a key focus in both the House and Senate in May, before the tense negotiations on the debt ceiling overwhelmed work on other issues in Congress and at the White House.

Biden issued a *fact sheet* outlining his permitting priorities, and Sen. Joe Manchin (D-W.Va.), chair of the Senate Energy and Natural Resources (ENR) Committee, declared his intention to have bipartisan legislation hammered out before Congress begins its August recess. (See *Podesta Lays out Biden's Priorities for 'Permitting Reform'*.)

House Republicans' original debt ceiling package, the Limit, Save, Grow Act (*H.R. 2811*), included a previously passed energy bill, the Lower Energy Costs Act (*H.R. 1*), with provisions that would accelerate permitting of fossil fuel projects, but without any mention of clean energy or transmission.

Capito and ENR Ranking Member Sen. John Barrasso (R-Wyo.) also introduced bills primarily focused on accelerating the leasing and permitting of oil and gas projects and slashing the window for NEPA legal challenges from six years to 60 days.

On the Democratic side, Manchin and EPW Chair Tom Carper (D-Del.) each introduced bills that called for two-year time limits on NEPA reviews but also contained provisions on transmission. Manchin's bill would cement FERC's authority to permit transmission deemed in the national interest. Carper's would authorize millions in federal funding to support broad community engagement in permitting processes, as well as training programs to ensure federal agencies are able to hire staff with the needed expertise. (See *Carper Throws Progressive Bill into Senate Permitting Debate*.)

Sen. John Hickenlooper (D-Col.) and Rep. Scott Peters (D-Calif.) added to the ongoing debate with their *Building Integrated Grids With Inter-Regional Energy Supply* (BIG WIRES) Act, which would require *transmission planning regions*, as defined by FERC, to be able to transfer at least 30% of their peak demand between each other. The bill calls on regions to pursue a range of options to achieve this target, from building new transmission and upgrading existing lines to cutting demand through energy efficiency.

BIG WIRES was on the table as part of the debt ceiling negotiations, according to *The Washington Post*, but was nixed by Reps. Cathy McMorris Rodgers (R-Wash.) and Jeff Duncan (R-S.C.), arguing that Republicans needed more time to review the bill. McMorris Rodgers is chair of the House Energy and Commerce Committee, while Duncan leads the committee's Energy, Climate and Grid Security Subcommittee.

The law's much-criticized transmission study was the result.

Without directly mentioning his bill, Hickenlooper expressed disappointment with the FRA's permitting provisions. "I don't feel that we got what I'd hoped we would get, and I feel like we gave up a little more than I would've wanted to give up," he told E&E.

Green Pivot Ahead?

The FRA's provisions calling for expedited completion of the Mountain Valley Pipeline (MVP) were another flashpoint during Senate debate on the bill Thursday. The 303-mile, 94% complete natural gas pipeline has been a top priority for Manchin, who until now had been unsuccessful in getting it into must-pass legislation.

Sen. Tim Kaine's (D-Va.) amendment cutting the project out of the bill was voted down, with some Democrats saying they agreed with Kaine but did not want to threaten quick passage of the FRA, *The Post* reported.

A key question now is whether, with completion of the MVP finally secured, Manchin will still push for a more comprehensive bipartisan permitting bill. As ENR chair, he has a formidable track record as a gatekeeper on issues and nominations he does not support, and he is facing a potentially *tough re-election campaign* against West Virginia Gov. Jim Justice (R) in 2024.

White House press secretary Karine Jean-Pierre on Friday included permitting in a list of issues Biden still hopes to tackle, but the president did not mention it in his *prime-time address* to the nation that evening.

Administration officials speaking at *The Economist*'s *Sustainability Week US* conference in D.C. on Wednesday stressed that work on permitting and transmission will continue.

"The job [on these issues] is definitively not done," said Andrew Mayock, federal chief sustainability officer. "Permitting remains a really important piece of the agenda … and I think it's safe to say that there is more to do, and the White House will continue to push on that until we get where we need [to be]."

Answering a question about the FRA-mandated transmission study, Gene Rodrigues, the Department of Energy's assistant secretary for electricity, said the study could have a positive impact by bringing "more people to the table to start thinking about what grid modernization means, and it's not changing out just poles and wires. It's about everything to do with how we plan, operate and invest in our system."

But, he said, "does that mean … everything else stops, and then we wait for that [study]

FERC/Federal News

to be done? Absolutely not. … Let's bring more people into the conversation, but let's continue moving forward with what needs to be done to support the reliability, resilience, affordability and security of America's grid."

Industry analysts ClearView Energy Partners even see a possible "green pivot" now that the debt deal is done and "the White House may not worry as much about alienating fossil-friendly Democrats or the GOP. … The White House may also seek to balance its support for MVP with new strictures on fossil fuels."

ClearView pointed to a *Friday notice* from the Interior Department withdrawing 336,404 acres surrounding *Chaco Culture National Historical Park* in New Mexico from potential mineral leasing and mining. The park marks the site of a once-thriving center of Pueblo culture, which existed between the 9th and 12th centuries.

'Reasonably Foreseeable'

The implementation of the FRA and its likely impacts on permitting and clean energy deployment in general also will likely become a matter of close political scrutiny in the months ahead, especially for GOP lawmakers.

While the bill calls for slashing time for NEPA reviews, from more than four years to two years for a full environmental impact study, hitting those deadlines may prove challenging.

The permitting provisions of the law are largely based on the Building U.S. Infrastructure through Limited Delays & Efficient Reviews (BUILDER) Act, which Rep. Garret Graves (R-La.) first introduced in 2021.

A chief GOP negotiator on the debt deal, Graves has said the new law would cut not only the time, but also the scope of NEPA reviews to "reasonably foreseeable environmental impacts," language taken from the BUILDER Act.

Speaking at a press conference announcing the deal May 28, Graves said, "NEPA has grown to just study all these things that don't have anything to do with the environment, which I would argue … has worked against the protection of the environment. So, we're trying to refocus the scope back on that, on the environmental impacts, and making sure we get the best environmental outcomes."

However, while the FRA incorporates many provisions of the BUILDER Act, it does not include that bill's definition of "reasonably foreseeable environmental impact." As defined in the *U.S. Code*, it is one that is "sufficiently likely to occur such that a person of ordinary prudence would take it into account in reaching a decision." Whether this definition is broad enough to include climate change or public health impacts will likely be a matter of ongoing debate and litigation.

The impact of the FRA's page limits also is uncertain. The law does limit each EIS to 150 pages, or 300 for "extraordinarily complex" projects, but it places no limits on appendices for such reports, which can run into hundreds or even thousands of pages. For example, the Bureau of Ocean Energy Management's recently released *final EIS* for the Ocean Wind 1 offshore wind project comes in four volumes, with 570 pages for the EIS itself (Vol. 1), plus 1,760 pages of appendices (Vol. 2-4). (See *BOEM: Major Visual, Scientific Impacts from NJ's 1st OSW Project*.)

Another question raised at *The Economist* conference was whether the FRA's clawback of $20 billion in Inflation Reduction Act funding for the Internal Revenue Service might affect the agency's ability to deliver the needed guidance for all the IRA's clean energy tax credits.

Heather Boushey, a member of the White House Council of Economic Advisers, cautioned that the clawback could send "a signal that that's maybe a cookie jar we can keep pulling from."

"It is clear in the short term — at least we are hearing from our Treasury colleagues — that they will be able to do their work, even with these cuts," Boushey said. "But I do think that we, as people who are concerned about climate, given how much of this is being done through the IRS, we need to be making sure that [Treasury] is on our checklist of agencies that we are watching very closely." ■

National/Federal news from our other channels

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DOE to Award $46 Million to 8 Commercial Fusion Developers — NetZero Insider

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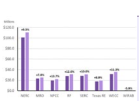
DOE Releases National Clean Hydrogen Strategy and Roadmap — NetZero Insider



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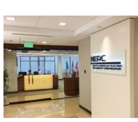

NERC's Standards Process Changes Pass on Second Ballot — ERO Insider

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FERC/Federal News

Robb Warns of 'Serious Disruptions' from Grid Transition

Senators Call for Reliability Focus in Power Transition

By Holden Mann

Testifying before the Senate Energy and Natural Resources Committee on Thursday, NERC CEO Jim Robb warned that operating the electric grid "ever closer to the edge" by relying on weather-dependent renewables will likely lead to "more frequent and more serious disruptions."

NERC CEO Jim Robb | *U.S. Senate*

Sen. Angus King (I-Maine) | *U.S. Senate*

Thursday's hearing focused on the reliability and resiliency of electric service in North America, and attendees often pointed to NERC's *Long-Term Reliability Assessment*, released last year, to illustrate their concerns.

The LTRA described most of the continent as at either high or elevated risk of energy shortfalls over the next decade, explicitly tying the shortages to the replacement of conventional generation with variable resources such as wind and solar power. (See *NERC Warns of Ongoing Extreme Weather Risks*.)

In light of the report, members took frequent potshots at EPA's recently proposed CO_2 emission standards for power plants, which some industry groups have criticized for potentially accelerating the retirement of coal power plants without equally reliable replacements. (See *Regan: New EPA Standards Designed to not Jeopardize Grid Reliability*.)

Republicans, including ranking member John Barrasso (R-Wyo.), also decried what he called the Biden administration's "reckless policies" that "are creating a reliability crisis."

Chair Joe Manchin (D-W.Va.) attempted to draw Robb on the subject, asking him "how frustrating is it to you, being the head of NERC, knowing that you're giving, basically, only the facts — you're not picking winners or losers, you're not getting involved in ... the fight that goes on [over climate policy], basically just dealing with the facts of how you're supposed to deliver the power, and no one pays attention?"

Sen. Joe Manchin (D-W.Va.) | *U.S. Senate*

Robb's reply was succinct: "It's frustrating."

Manchin brought up the *SPUR Act*, a bill introduced by Barrasso that would require NERC to comment on proposed EPA regulations and require the agency to "address NERC's comments before [issuing] a final rule." He framed the proposal as a way to force the EPA to account for the real-world impacts of its decisions.

"NERC and FERC [are] doing their job, but there's no teeth to it whatsoever," Manchin said. "Somehow you have to have reliability ... be the first and foremost ... to protect [people's] livelihoods and lives."

Robb's fellow witness Manu Asthana, CEO of PJM, called the SPUR Act "a great idea," adding that, "I think, actually, we can go further." In his opening statement, Asthana agreed with Robb that the "rapid rate" of dispatchable generation retirement, with replacement renewable generation coming online more slowly than anticipated, has the potential to cause "increasing resource adequacy risk."

King Says Transition Coming Late

Some committee members pushed back against the idea of slowing down the transition to renewable energy. Sen. Angus King (I-Maine) drew attention to the "irony and paradox" of witnesses and committee members calling the grid transformation "premature" and demanding the retention of conventional generation. Pointing out that the American Society of Civil Engineers attributes severe weather as the primary cause of customer outages, he argued that the reliability risks are as bad as they are because coal and natural gas generation was retained too long in the first place.

"We're talking about outages that are caused predominantly by severe weather, which is a result of climate change," King said. "So, the question is — [is the transition] premature? We should have been making this transition years ago, and we're trying to make it in a hurry, because we are in a crisis situation."

Robb acknowledged that the question of balancing the related harms of retaining carbon-emitting generation and moving to intermittent renewables is "a very tough policy problem," but he stopped short of offering a solution, calling it a "question of balance that policymakers need to figure out."

King pressed Robb for a timeframe in which older generation could be retired, but Robb would only say it should not be done until suitable replacements — such as renewable facilities with sufficient storage capacity to ride out significant grid disturbances — are available.

"The question is how fast can we develop the battery or the storage technology, whatever it is ... versus the contribution to the severe weather events" of thermal generation, King said. "We're talking [in] this hearing as if the only risk is lack of capacity, when in reality the risk is severe weather events." ■

Calif. Bill to Speed Tx Development Passes State Senate

Legislation Would Allow Some Projects to Choose CEC's Expedited Approval Process

By Robert Mullin

A bill to accelerate the development of new transmission lines in California passed the state Senate last week on a vote of 36-0 and is now headed for the lower house.

Senate Bill 619 would expand the authority of the California Energy Commission (CEC) by extending the agency's existing "opt-in" permitting process to include new transmission lines that require a capital investment of at least $250 million over five years — although many such projects would still be excluded.

While not part of Gov. Gavin Newsom's recently introduced legislative package to expedite the development of clean energy resources through looser permitting, SB 619 falls in line with the governor's efforts, which last month took on a new sense of urgency. (See *Newsom Stresses Role of Permitting in Calif. Energy Transition*.)

"California's efforts to build the clean energy supply of the future will fall flat if we rely on the grid of the past," bill sponsor Sen. Steve Padilla (D) said in a statement May 30. "We must act now, to approve new projects and expand our transmission capacity. The state needs to triple the size of our grid over the next decade, and we are falling behind every single day."

The CEC's opt-in process is the product of a 2022 law (*AB 205*) that authorized the agency to create a new certification and permitting program that allows developers of nonemitting energy resources and related facilities — including transmission — to optionally seek approval from the CEC instead of a local permitting authority.

To be eligible for the process, a project must qualify under California's Environmental Leadership Development Project program, which entails stringent environmental and labor provisions. SB 619 would expand the CEC permitting process to also include point-to-point transmission lines that function as more than just tie-ins for generating or storage resources.

'Substantial Delays'

Under current California law, developers of point-to-point lines are prohibited from beginning construction before obtaining a certificate of public convenience and necessity (CPCN) from the California Public Utilities Commission — or, in the case of publicly owned utilities (POUs), a permit from a local authority.

The CPUC's CPCN process includes both an environmental review under the California Environmental Quality Act (CEQA) and an evaluation of project need and costs. Critics — including Padilla — have blamed that process for the lack of needed new transmission in California.

SB 619 is intended to speed the development of new transmission lines in California by expanding the approval authority of the state's Energy Commission. | *© RTO Insider LLC*

"Despite the overwhelming need to expand our electrical grid, the California Public Utilities Commission has not authorized a new transmission project in over a decade," the senator's office said in its statement. "The current process requires multiple agencies, duplicative analyses, and permitting processes that take years to complete and create unnecessary cost overruns and substantial delays."

SB 619 would allow a subset of transmission developers to circumvent those processes by opting into CEC review. But even if it passes, the bill might have a limited role in spurring construction of new transmission. That's because it explicitly states that it will not contravene the CPUC's oversight over transmission lines proposed by any utility falling under CPUC jurisdiction, which includes Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric — the investor-owned utilities that serve more than half the state.

"The supporters of this bill acknowledge this limitation and recognize that additional work would be needed to make any changes to the existing CPUC's authority related to permitting transmission projects," said a *bill analysis* provided to senators before the floor vote. "Instead, this bill would capture a more limited set of transmission projects, those serving publicly owned utilities (POUs), which would otherwise be permitted by local governments."

According to the analysis, bill supporters include Clean Air Task Force, Clean Power Campaign, 350 Humboldt: Grassroots Climate Action, Elders Climate Action and San Diego Community Power.

"SB 619 is a much needed reform to expedite approvals of badly needed new transmission, to expand solar, wind, and batteries, and enhance affordability and reliability," V. John White, legislative director for Clean Power Campaign, said in a statement after last week's vote.

The Senate's advancement of SB 619 could herald the passage of similar bills from Newsom's legislative package. Those include proposals to *streamline* judicial review of certain clean energy and transportation projects by requiring that challenges under the CEQA be resolved within 270 days and a related *measure* to streamline procedures for the preparation of the public record for court review of CEQA challenges. ■

CAISO/West News

WEIM Wins FERC OK for Resource Sufficiency Changes

By Robert Mullin

FERC on Wednesday approved CAISO's proposed changes to the Western Energy Imbalance Market's resource sufficiency evaluation (RSE), including a provision to allow energy transfers to members who fail to meet resource obligations ahead of a trading interval (ER23-1534).

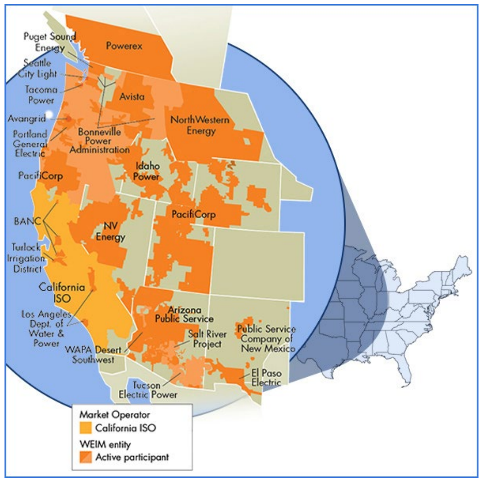
The package of changes was part of a second round of RSE-related tariff revisions, which were approved by the CAISO Board of Governors and WEIM Governing Body in December. (See *CAISO, WEIM Boards Back Reliability Enhancements*.)

The RSE test is designed to ensure that each WEIM participant enters a trading hour with enough capacity and ramping capability to cover its own needs and to prevent participants from "leaning" on the market to meet internal demand. A balancing authority area (BAA) that fails the test before an operating hour is prohibited from receiving WEIM transfers during that interval.

But meeting that requirement has become a challenge for some participants as the West faces a worsening shortage of generating resources and declining liquidity in the regional bilateral electricity market that typically helps provide short-term resource sufficiency — which stakeholders attribute to the expansion of the WEIM itself.

The RSE consists of four tests that measure feasibility, balancing, capacity and flexibility. The rule changes approved Wednesday relate to the capacity test, which determines whether a WEIM participant has provided sufficient incremental bid-in capacity to meet the imbalance among load, intertie and generation base schedules.

The first rule change will allow CAISO to establish a process by which participants that fail the RSE can obtain "energy assistance" transfers from within the WEIM. Any BAA that receives such assistance will be subject to a surcharge on top of the cleared price for energy assistance transfers.



The Western Energy Imbalance Market, which now covers about 80% of the load in the West, must deal with increasing energy shortages in the region. | *CAISO*

"The EIM assistance energy transfer surcharge is an after-the-fact charge designed to provide an alternative incentive for WEIM balancing authority areas to meet their resource sufficiency obligations during tight supply conditions while making additional supply available to other balancing authorities in the WEIM," FERC noted in its order.

CAISO plans to align the surcharge with the level of its soft ($1,000/MWh) or hard ($2,000/MWh) energy bid caps, depending on system conditions. It says energy assistance transfers will be voluntary for both the provider and recipient.

In approving the tariff revision, FERC concluded that CAISO's plan "provides increased flexibility to WEIM participants and can help WEIM balancing authority areas to meet their resource sufficiency obligations during tight supply conditions.

"We also find the proposal allows CAISO to optimally dispatch supply and provide access to resources that were not otherwise available," it said.

The rule change had particularly strong backing from WEIM member NV Energy. The Nevada-based utility faces increasingly critical shortages of resources during summer and has been seeking a legislative remedy to address the issue. (See *Bill Would Require NV Energy to Examine Market Reliance*.)

In a December letter to the CAISO and WEIM boards, Lindsey Schlekeway, NV Energy's market policy manager, noted that her company had asked the ISO to develop a mechanism to make excess supply available to a "distressed EIM entity at an appropriate scarcity price" and said "it is of critical importance not to delay the implementation of this reliability enhancement past the summer of 2023 for grid reliability."

Asymmetry Addressed

CAISO's second and third RSE rule revisions focus specifically on the ISO itself.

The second change will allow the grid operator to exclude from its own RSE calculation any real-time "lower priority" energy exports out of its BAA. Those exports are currently included in the calculation even though the ISO can freely curtail them to meet its own load obligations. At the same time, real-time WEIM transfers into the ISO are not factored into the RSE, representing an asymmetry in treatment of transfers, CAISO argued. Inclusion of curtailable exports has caused CAISO to fail RSE tests that it would have otherwise passed, the ISO said.

FERC said CAISO's proposal "helps mitigate this asymmetry and will improve the ability of the resource sufficiency test to more accurately reflect actual system conditions during periods of potential resource insufficiency."

The third rule change pertains to scheduling priority rules and E-Tag requirements for lower priority exports, with CAISO clarifying how it will interpret its scheduling priority tariff provisions to ensure that it can manually curtail lower priority exports in real-time to meet its own supply obligations.

"We find that these clarifications are consistent with CAISO's existing authority to apply the scheduling priorities and help provide better transparency for market participants," FERC wrote. "Further, we find that these clarifications could help operators identify lower priority exports and priority exports for scheduling and manual curtailment purposes." ■

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Wash. Looks to Sell 11M Allowances in 2nd Cap-and-Trade Auction

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CAISO/West News

WEIM Sees Record Q1 Benefits with Growth of Footprint

Four New Participants Help ISO Achieve Greater Economic Benefits

By Robert Mullin

CAISO's Western Energy Imbalance Market yielded members $418.82 million in economic benefits during the first three months of 2023, up 143% from the same period in 2022 and a first-quarter record.

Cumulative benefits since the 2014 rollout of the market have nearly doubled over the past year, reaching $3.82 billion after three consecutive quarters that smashed records, according to CAISO's first-quarter benefits *report*, released Thursday.

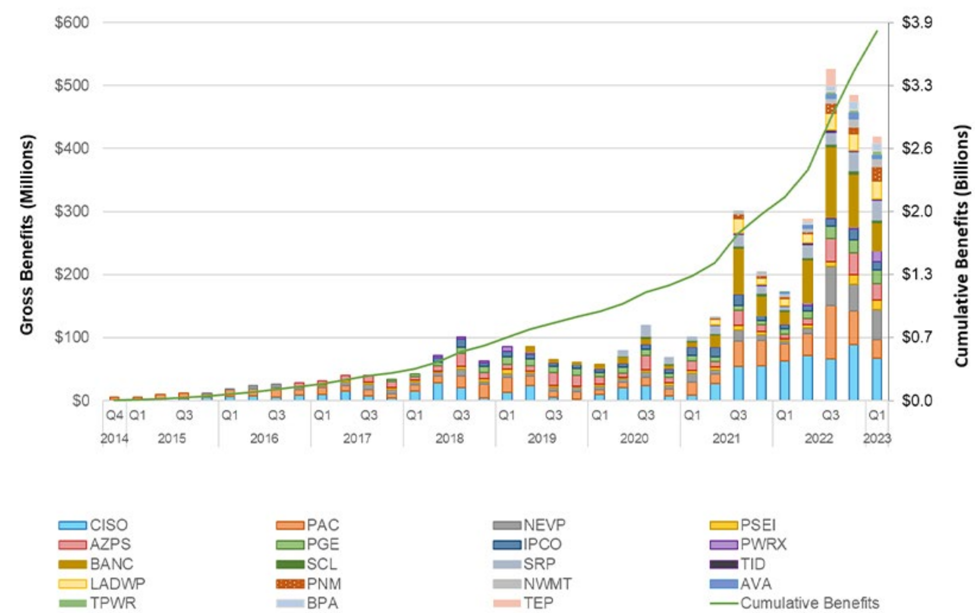
The sharp growth comes after four new participants entered the market last year: Avista Utilities, Tacoma Power, Tucson Electric Power and, most significantly, the Bonneville Power Administration, which operates 15,000 miles of high-voltage transmission — about 70% of the network in the Northwest.

The first-quarter benefits report was released about a month later than normal, which the ISO attributed to the need for more time "to review the benefits estimates and the underlying congestion observed in certain areas of the WEIM footprint," according to a *press release* accompanying the report.

"Ultimately, no changes to the current methodology have been implemented to estimate the first quarter benefits. The CAISO and its WEIM partners will continue to assess and determine if methodology enhancements are warranted based on various conditions of congestion," the ISO said in the release.

CAISO itself earned the largest share of benefits during the quarter, at $67.86 million, followed by NV Energy ($47.19 million), Balancing Authority of Northern California — or BANC ($44.63 million), Salt River Project — or SRP ($31.38 million), PacifiCorp ($28.94 million), and Los Angeles Department of Water and Power ($27.99 million).

BANC's balancing authority area includes the state's second-largest municipal utility, Sacramento Municipal Utility District, as well as Modesto Irrigation District, the cities of Redding and Roseville, and the Western Area Power Administration's Sierra Nevada region.



Cumulative economic benefits for each quarter by BAA | *CAISO*

CAISO was the largest net exporter of energy during the quarter, at 1,354,826 MWh, followed by SRP (510,350 MWh), NV Energy (478,330 MWh) and PNM (350,796 MWh). The ISO was also the second-largest net importer, at 848,513 MWh, exceeded only by British Columbia's Powerex, at 881,791 MWh.

CAISO was also the location of the most wheel-through transfers, at 760,999 MWh, followed by Arizona Public Service (587,198 MWh), the PacifiCorp-West BAA (314,838 MWh) and NV Energy (296,657 MWh). In years past, NV Energy consistently handled the highest volume of wheel-throughs, but the inclusion of more Pacific Northwest WEIM participants appears to be shifting a greater share of those transfers to California. Market members gain no financial benefit from facilitating wheel-throughs, with only the sink and source directly benefiting.

CAISO said WEIM operations helped reduce renewable curtailments by 53,002 MWh during the first quarter, helping to prevent emission of 53,002 metric tons (MT) of CO_2. The market has avoided 814,746 MT of carbon emissions since 2015, the ISO estimates.

With the inclusion of the Western Area Power Administration–Desert Southwest region and Avangrid in April, the WEIM footprint now covers 79% of the load in the Western Interconnection. CAISO expects the market to break $4 billion in total benefits this quarter. ■

West news from our other channels

Berkeley Seeks Rehearing of Gas Ban Decision

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

FERC Approves PG&E's Proposal to Spin off Generation

Utility Plans to Sell Minority Share in a Later Deal to Raise Capital

By James Downing

PG&E's San Francisco headquarters | *Minesweeper, CC BY-SA 3.0, via Wikimedia Commons*

FERC on Wednesday approved Pacific Gas and Electric's transaction to spin off its non-nuclear generation to a new subsidiary called Pacific Generation (*EC23-38*).

The firm plans to sell off up to 49.9% of the generation subsidiary so it can raise capital more efficiently than through the sale of additional stock in parent company PG&E.

Pacific Generation will become a certificated, cost-of-service public utility regulated by the California Public Utilities Commission in the same franchise territory as PG&E after the deal closes, providing cost-based generation to customers and selling some power into the CAISO market under a market-based rate tariff the firm will file with FERC.

The generators being spun off include 3,848 MW of hydro, 1,400 MW of natural gas units, 152 MW of solar and 182 MW of storage.

The proposal led to protests from the California Community Choice Association, the Transmission Agency of Northern California (TANC), Northern California Power Agency (NCPA) and Public Citizen. (See *Parties Protest PG&E Plan to Spin Off Generation*.)

The community choice aggregation association argued that without detailed information on which firm will buy the generation, its impact on vertical market power cannot be determined. FERC sided with PG&E, saying that spinning off the generation to a new subsidiary that does not provide any inputs to electricity products will not lead to vertical market power concerns.

While the utility promised to hold its customers harmless in the transactions, the city of Santa Clara, TANC, Public Citizen and NCPA said that was not enough to ensure that outcome. PG&E should look into less disruptive ways to raise capital, Public Citizen said.

TANC noted that PG&E wants to issue up to $2.1 billion in debt for the new firm, whose assets will value about $3.5 billion. It argued that FERC should require the company to show its accounting treatment and whether the deal would alter PG&E's equity ratio. The utility provided no information on which costs transmission customers will be held harmless, which makes it impossible to determine whether that will actually happen, TANC said.

FERC determined that the deal would not affect rates. When it comes to wholesale rates, the assets will be bid at market prices, which will not be impacted by the seller's cost-of-service retail rates.

Pacific Generation has yet to file a request for market-based rate authority; FERC said its approval is based on the new firm getting that authority before the deal closes.

"Failure by Pacific Generation to obtain market-based rate authority as PG&E represents in its application would constitute a material change in circumstances that we rely on in making our findings herein," FERC said.

The commission also said the protesters failed to show the deal would impact PG&E's cost of capital or transmission rates. The deal would not impact the firm's return on equity, its credit rating or its capital structure, so claims to the contrary lack a factual basis, the commission said. It noted, however, that if those change, then that would also represent a material change to the facts relied upon in its approval.

FERC also found the deal would not affect rates, as the new subsidiary and the utility will still be regulated by it on the wholesale side, and the CPUC on the retail side.

Public Citizen argued that the transfer of generation to private equity could impair state oversight, but FERC said that is beyond the scope of the proceeding because it focused on the spinoff, not any later sales.

The deal would not lead to any cross-subsidization issues, where benefits are transferred from captive customers to shareholders, because both the utility and Pacific Generation will be regulated by the CPUC, FERC said.

"A debt issuance by Pacific Generation for the benefit of its utility affiliate, PG&E, is not analogous to a situation where the assets of a franchised public utility with captive customers are used to finance its market-regulated utility affiliates or nonutility affiliates or their activities, which the commission has stated may raise concerns," FERC said.

Many of the protests argued that FERC should consider the spinoff and the subsequent sale of a minority interest in the generation at the same time, but the commission disagreed, saying expanding the proceeding to cover the second deal would be inappropriate. ■

CAISO/West News

FERC Approves New Rules to Enhance Battery Performance in CAISO

Opportunity Cost will Help Address Storage Timing Use Concerns

By James Downing

FERC on Thursday approved new rules for CAISO intended to improve the performance of energy storage resources and ensure reliability (*ER23-1533*).

The first of the four new rules will pay storage resources their opportunity costs when they get an exceptional dispatch to hold a state of charge for use later when they are most needed by the grid.

FERC also approved changes to the day-ahead default energy bid for storage to avoid a situation where mitigated bids were causing storage resources to be dispatched in the afternoon, rather than the evenings, when they are needed most. That will be fixed by adding an opportunity cost like the one used in the calculation of real-time default energy bids for storage resources.

The third change relates to how storage resources bid into ancillary services markets to ensure they have enough charge to provide what they bid for. Storage resources will have to submit accompanying energy bids in the real-time market that cover at least any capacity awarded for ancillary services from the day-ahead market.

If a resource deviates from the state of charge anticipated in the day-ahead market and is in danger of not meeting its ancillary services award, then the real-time bid will ensure the resource will still be able to charge or discharge.

FERC approved the first three proposed rules, which did not lead to any debates in the docket.

The final rule change makes it so storage resources are scheduled to provide only the regulation they are capable of, given their constraints.

Vistra, which owns two large storage facilities in CAISO, protested that last rule, saying it gives the ISO broad discretion to account for how regulation awards affect state of charge when determining regulation commitments without providing any detail regarding the parameters and rules that will be used to determine states of charge.

FERC agreed with CAISO that the revisions clarify its responsibility to provide storage resources with achievable regulation awards, given their constraints. The new rules clarify the ISO's responsibility to continue to refine its optimization software based on storage's inputs and operational experience in providing regulation, it said.

The commission was not persuaded by Vistra's protest, saying the language the ISO filed is similar to other parts of the tariff describing how the grid operator optimizes its system. Such provisions require the ISO to take numerous dynamic factors into account in market optimization, but they do not establish new static parameters or standards.

CAISO included examples of how the rule might work in its Business Practice Manuals, which FERC said are also consistent with current practices. The manuals are meant to be guides for internal operating procedures and to inform market participants of the ISO's practices.

The manuals do not affect any rates, terms or conditions, and the examples in question do not belong in the actual tariff as Vistra contended, FERC said. ■

Vistra's Moss Landing battery storage project in California | *Vistra*

ERCOT News

Clean Energy Escapes Texas Legislature's Wrath

2023 Session Could Have Been 'Very, Very Bad' for Renewables

By Tom Kleckner

With the 88th Texas Legislature's regular session in the history books last week, and a 30-day special session already underway, the state's clean energy industry can breathe a little easier again.

"Members, I hope you enjoyed your summer. I sure did," House Speaker Dave Phelan (R) said as he gaveled his chamber back to business May 30.

The consensus is that the industry, which an Austin-based research firm says *reduced wholesale electricity costs* in the state by almost $28 billion from 2010 to 2022, fared better than recent gloomy predictions. (See *Uncertain Future for Texas' Renewables Industry*.)

"It could have been very, very bad," Stoic Energy principal Doug Lewin, a close observer of the Legislature, told *RTO Insider*. "The threats were serious and real, and it's still not great … the worst stuff, the permitting, the cost allocation … that didn't pass."

"While more than a dozen anti-renewable energy bills were filed this session, only a few ended up making it through the process," said Luke Metzger, executive director of Environment Texas. "Some of the measures that would have been most harmful to renewables … thankfully died."

For that, Metzger and others can thank a broad coalition of environmentalists, industry organizations and business groups, along with House representatives beholden to their constituents, for preventing the renewable energy sector from being kneecapped.

After the Senate tacked on language from bills that had yet to make it out of committee as amendments to the must-pass bill reauthorizing the Public Utility Commission (*House Bill 1500*), the interest groups worked over the Memorial Day weekend with legislators to again eliminate or water down the more onerous language.

Out went language from *Senate Bill 624* that would have required wind and solar facilities to acquire special permits from the PUC, a requirement that thermal generators wouldn't face. A firming mandate that would have required renewables to pay for other energy sources when wind and solar aren't producing was pushed back to the end of 2027 and its

Texas legislators burned the midnight oil last weekend during the last days of the 88th Legislature. | © *RTO Insider LLC*

cost increases tied to generation portfolios, rather than individual units.

"Over at the legislature, those people are accountable to consumers and voters. They just can't ignore what consumers want," said attorney Katie Coleman, who represents Texas Industrial Energy Consumers.

"I think the language that ended up in 1500 is heading in the direction of trying to have some reliability for renewables in their output, but it's not as punitive as some of the other proposals," Lewin said. "I think there's a lot of what they're calling firming going on in the market anyway. So, kind of pushing that along, but I don't think it is going to really be that detrimental to the industry."

Rather than make renewables pay higher ancillary services fees, HB1500 instead requires that a study first be conducted. It would also end Texas' renewable energy requirement, or portfolio standard. However, the state met that requirement years ago.

HB1500 also adds a $1 billion annual net cap to the performance credit mechanism (PCM), which since PUC Chair Peter Lake pushed it through in January has been criticized by almost everyone connected to the market — except the large generators that would benefit from it. Various studies have pegged the PCM's cost at between $5 billion and $12.7 billion a year, which ERCOT has said would flow down to consumers. (See *Texas PUC Submits Reliability Plan to Legislature*.)

Lake said the commission would wait to see what direction the Legislature offered before pursuing the PCM's implementation. The PUC got that direction with HB1500, which requires ERCOT to complete an updated assessment of the reliability program and submit a report on its costs and benefits to the commission and Legislature.

The bill also includes 14 requirements to be met before the PCM can be implemented, including one that mandates that ERCOT add real-time co-optimization and ancillary services to the market before implementing the PCM. That would push the latter back to 2025 or 2026.

Other HB1500 requirements related to the PCM include:

- Central procurement of performance credits to prevent market manipulation by affiliated

ERCOT News

generation and retail companies;

- Not assigning costs, credit or collateral for the program such that it provides a cost advantage to load-serving entities that own, or whose affiliates own, generation facilities;
- Establishing a penalty structure providing a net benefit to load for generators that bid into the PCM's forward market but do not meet the full obligation;
- Not allowing generators to receive credits that exceed the amount of their bid into the forward market;
- Removing the bridge solution by the end of the PCM's first year; and
- Setting a single ERCOT-wide clearing price that does not differentiate payments or credit values based on locational constraints.

"There really hasn't been a lot of support for [the PCM] from any group other than actual existing generators and leadership with the PUC and ERCOT," Coleman said. "We all want more reliability. Always. I think the Legislature wanted to put some pretty strict parameters around the limits of it. That was something that we worked really hard to get done, along with a pretty broad range of groups."

Hard Sell

Where this leaves the PCM is anyone's guess.

During a virtual press conference Wednesday, ERCOT CEO Pablo Vegas said the grid operator's staff are reviewing legislation that passed and analyzing its impact on the grid. He promised to share more details publicly, "like we often do in our in our open board meetings," once staff understand the bills better.

Texas Rep. Todd Hunter and Texas Sen. Charles Schwertner celebrate the passage of House Bill 5. | *Sen. Charles Schwertner via Twitter*

"We're not at a place where we're ready to discuss that in any detail right now," he said. "But I can tell you that we share the same goal that the Legislature does, which is to continue to support a reliable and stable grid now and long-term into the future. We'll continue to work closely, too, with the Legislature to enact what they passed this session."

The ERCOT Board of Directors next meets June 19-20.

"I think it's going to be a hard sell to come back and say, 'Hey, we've done this analysis and now the PCM is going to cost $2 billion or $3 billion or $4 billion.' That's going to be hard, hard argument to make," Coleman said.

The Legislature also sent *SB2627* to Gov. Greg Abbott's desk. The bill provides $5 billion to $10 billion in government low-interest loans and completion bonuses to builders of new gas plants. However, SB6, which would have ordered the construction of 10 GW of gas-fired generation at a cost of $10 billion to $18 billion, didn't make it. Texans will get a chance to pass judgment on SB2627 when they vote on it as a constitutional amendment.

Another bill, *HB5*, a corporate incentive program to boost infrastructure investment, excludes wind and solar development from tax abatements.

"The landmark legislation package passed this evening will ensure our economic miracle continues into the mid-21st century and beyond," Lt. Gov. Dan Patrick, who controls the Senate, said in a *statement* after the bills' passage.

Lewin points out that very little of the legislation addresses the root causes of ERCOT's capacity shortfalls during the two most recent storms of 2021 and 2022: the failure of gas supplies to show up in frigid temperatures.

He said a friend asked him after the regular session ended whether the Legislature's actions meant the grid is fixed.

"No. Not even close," Lewin said he responded.

"One of the points I'm trying to make leaving this session is that if you don't focus on the root cause, if all the focus is on renewables, you're causing problems, which is really where the focus was," he said. "There was very little focus on the actual problems facing the grid. We're just going to continue to have a grid that is problematic and leaves us all kind of white-knuckling it through the through the next winter storm." ■

ERCOT News

ERCOT Monitor Recommends New Market Design in Report

Grid Operator Unveils Additions to Notification System

By Tom Kleckner

The ERCOT Independent Market Monitor's annual market report on the Texas grid released Wednesday recommends resurrecting a multi-interval, real-time design similar to those used in other markets and re-evaluating and prioritizing it for future implementation.

The Monitor notes that real-time markets rely primarily on online and quick-start resources. It says a real-time market efficiently dispatches online resources and sets nodal prices that reflect energy's marginal value of energy at every location, but that ERCOT lacks the software and processes to facilitate efficient commitment and decommitment of peaking resources that can start within 30 minutes.

"This is a concern because suboptimal dispatch of these resources raises the overall costs of satisfying the system's needs, can distort the real-time energy prices and affects reliability," the Monitor says in its *2022 State of the Market report*. "For these reasons, other markets have implemented this type of look-ahead process to optimize short-term commitments of peaking resources."

The Monitor says the value of access to and optimally using fast-starting dispatchable resources will only grow as do ERCOT's more intermittent wind and solar resources. A multi-interval dispatch model can meet these increasing ramp requirements by recognizing system needs further into the future and beginning to move dispatchable resources to optimally satisfy, it says.

ERCOT evaluated the model's potential benefits in 2017 but decided not to move forward because the costs were greater than the projected benefits, according to the IMM. "Much has changed since" then, it says, pointing to a higher level of renewable resources available to the grid operator.

"We believe benefits will be much higher in the future, and this capability will become essential for managing the growing renewable fleet," the Monitor says.

The proposal is one of five new recommendations added to eight holdovers. Other new suggestions include:

- instituting a 100% claw-back of excess market revenues for reliability unit commitments, as the incentives for self-committing resources have changed "dramatically" with the increased frequency of RUC instructions under ERCOT's more conservative operations posture;
- allowing transmission reconfigurations for economic benefits, instead of just for reliability;
- changing the linear ramp period for emergency response service summer deployments to three, down from the current 4.5-hour parameter that artificially inflates the reliability deployment price adder; and
- modifying the lookback period for operating reserve demand curve mean and standard deviation calculations to a rolling five-year period, which would have saved more than $160 million last year.

ERCOT CEO Pablo Vegas | *ERCOT*

The IMM also says real-time co-optimization (RTC), which was postponed after the February 2021 winter storm, should be prioritized, "given its promise to improve pricing during supply shortages" and to better use the existing generation fleet. The grid operator is expected to restart the RTC project this summer, with a new potential go-live of 2026.

The market report finds ERCOT's markets performed "competitively" and "little evidence" that suppliers exercised market power, with one exception: It says the nonspinning reserve market became less competitive as higher procurements caused large suppliers "to frequently be pivotal," raising the reserve product's costs from $385 million to $480 million from August 2021 through December 2022.

ERCOT's average load grew 9.5% from 2021 and average real-time prices fell to roughly $75/MWh in 2022, down more than 50% from 2021 ($167.88/MWh), almost entirely because of the February storm's effects. Prices reflected a real-time energy value of $32.2 billion last year.

New Grid Notifications Added

ERCOT on Wednesday rolled out a new notification system it said will provide "clear and reliable" communications with the public and greater transparency on grid operations.

The *Texas Advisory and Notification System* (TXANS) provides another means for the public to follow ERCOT operations and grid conditions that do not indicate emergency conditions are expected. It introduces two new notifications before NERC-mandated energy emergency alerts (EEAs): an ERCOT weather watch and a voluntary conservation notice.

The weather watch will be issued when possible severe weather and high demand is forecasted in three to five days. It is intended to alert the public to plan ahead in reducing their energy use during higher-demand periods.

"This earlier lookahead gives the public notification of possible higher demand due to forecasted conditions," ERCOT CEO Pablo Vegas said during a virtual press conference. "We're then asking Texans to keep an ear out for more information should conditions change."

The voluntary conservation notice will be issued when higher demand and lower energy supply are forecast. It will ask Texans to voluntarily conserve power, if it's safe to do so. ERCOT will also request that local government agencies implement programs that reduce energy use at their facilities.

TXANS notifications will not replace EEA notices.

"All of the new notices that we are releasing at this point … are times when the grid is in stable and normal conditions and that they're not in an emergency," Vegas said. "We want to just help people be aware and informed on what's going on. We want to be more transparent; we want to be more open and get people more comfortable with hearing from us under conditions that are not emergency conditions." ■

ERCOT News

Carbon-capture Plant Coming Back into Service

Petra Nova Facility Mothballed Since 2020

The Petra Nova carbon-capture facility's owner has told ERCOT that it plans to bring the plant out of mothballs and into year-round service this month.

Japanese oil and gas company JX Nippon filed a notification May 28 with the grid operator that it intends to bring the world's largest carbon-capture plant back June 28. The plant has been shut down since 2020, during the height of the COVID-19 pandemic and in the face of slumping oil prices. (See *NRG to Mothball Petra Nova CCS Plant*.)

Petra Nova has a summer capacity of 71 MW and was retrofitted at a cost of $1 billion to capture carbon from one of the nearby W.A. Parish Generating Station's coal-fired units. NRG Energy, which operates Parish, must complete repairs on the unit Petra Nova is connected to before it can return to service.

The Petra Nova plant is coming back online. | *NRG Energy*

NRG and JX were partners in the carbon-capture project. JX bought NRG's 50% stake for $3.6 million and closed the deal shortly after Congress passed the Inflation Reduction Act last August. The legislation includes a significant increase for the carbon-capture tax credit.

Petra Nova went online in December 2016. It sequestered more than 3.9 million tons of carbon dioxide in three years, despite frequent outages.

Also last month, Calpine *said* four gas units at its Deer Park Energy Center near Houston will be converted from generation resources to settlement-only, transmission self-generators as of Oct. 27. The resources each have a summer seasonal rating of 190 MW. ■

— Tom Kleckner

ERCOT News

Texas PUC's Lake Steps Down as Chair

Governor Praises Lake, Who Touts Grid Reliability Work

By Tom Kleckner

Peter Lake, appointed to restore the Texas Public Utility Commission's credibility after the disastrous 2021 winter storm, said Friday he is stepping down as PUC chair.

His resignation comes after he apparently lost the faith of Texas lawmakers. Lake pushed forward a complicated and novel market design, the performance credit mechanism (PCM), that would benefit primarily thermal generation. The Texas Legislature took little action on the PCM during its recently concluded session other than proposing guardrails that would reduce its financial benefits. (See *Clean Energy Escapes Texas Legislature's Wrath*.)

Gov. Greg Abbott announced Lake's resignation late Friday afternoon, a time normally reserved for dumping bad or uncomfortable news and hoping it goes unnoticed over the weekend. Abbott, who appoints members to the five-person commission, promised to name a new chair "in the coming days."

Lake will leave the PUC July 1, two months before his term expires.

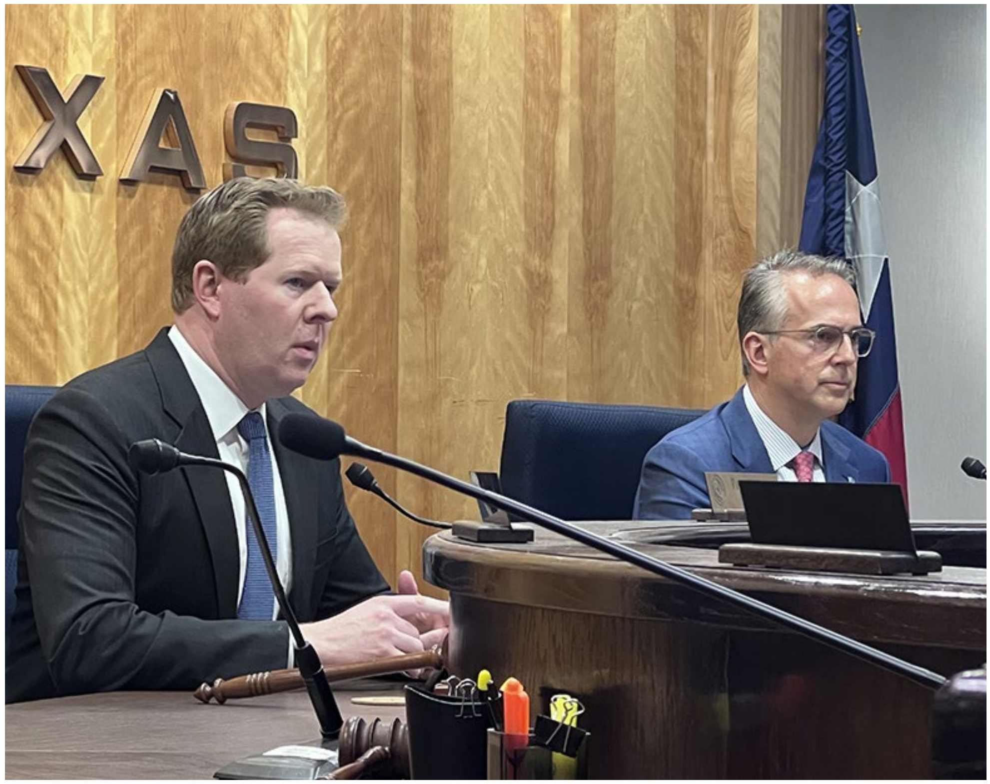
"The most surprising unsurprising news," said one industry insider, who wondered whether Lake really enjoyed his job.

Other ERCOT stakeholders weighed in as well.

Attorney Katie Coleman, who frequently testifies before the PUC and represents Texas Energy Industrial Consumers, *tweeted* that she and Lake disagreed on market policy, but that he "had good intentions, tried to bring a fresh perspective, and put in a lot of long hard hours for the state."

"He will be remembered for his lack of knowledge of simple microeconomics, unexplained support of the anti-market and pro-oligopoly PCM model, and attempting to implement an authoritarian power structure by removing stakeholders from the ERCOT process," *tweeted* another interested observer, who uses the ERCOT Traders Anon handle.

The grid operator's market participants have been largely sidelined by 2021 legislation that replaced the previous board, composed of market participants and independent directors, with eight independent directors selected by the state's political leadership. The board then created a reliability and markets subcommittee that creates another layer of separation between stakeholders and the directors.



Peter Lake (left) with ERCOT CEO Pablo Vegas during recent press conference | *Texas Public Utility Commission*

Asked about the PCM's fate, a PUC spokesperson said it would be "premature" to discuss any legislation's effect until it becomes law.

Abbott selected Lake to lead the PUC in April 2021, saying he was confident Lake would "bring a fresh perspective and trustworthy leadership to the PUC."

Lake replaced DeAnn Walker, who resigned under pressure following the February winter storm that nearly collapsed the ERCOT grid and led to days of blackouts that killed hundreds of Texans and caused billions in financial damage. (See *Abbott Appoints New Texas PUC Chair*.)

In a statement provided by the PUC, Lake thanked Abbott for the "incredible opportunity" to serve the state.

"When I arrived at the [PUC] in April 2021, our electric grid was in crisis," he said. "Thanks to the hard work of the teams here and at ERCOT, and my fellow commissioners, today our grid is more reliable than ever. While there are challenges ahead, I know the [PUC] is well positioned to continue the incredible progress we've made."

During Lake's tenure, the PUC ordered weatherization requirements for generators and transmission facilities, made it easier to build transmission facilities, and directed ERCOT to make several tweaks to the market. However, as with the PCM, he also focused on dispatchable, or thermal, generation and highlighted renewable energy's intermittency.

Abbott praised Lake for being a "true public servant who stepped up during a critical time in our state" to rebuild the PUC and "Texans' trust in those charged with providing reliable power."

"With Lake at the helm of the PUC," Abbott said, "we have ensured that no Texan has lost power due to the state grid" since legislation passed in the wake of Winter Storm Uri.

Lake previously chaired the Texas Water Development Board, which provides planning for the state's water resources and wastewater services. He brought a financial background with him, having led business development at Lake Ronel Oil and special projects for equity firm VantageCap Partners. ■

ISO-NE Increases Peak Load Forecasts

Transportation, Building Electrification to Drive Demand

By Jon Lamson

HOLYOKE, Mass. — ISO-NE has upped its predictions for summer and winter peak loads over the next 10 years, staff told the NEPOOL Power Supply Planning Committee on Wednesday.

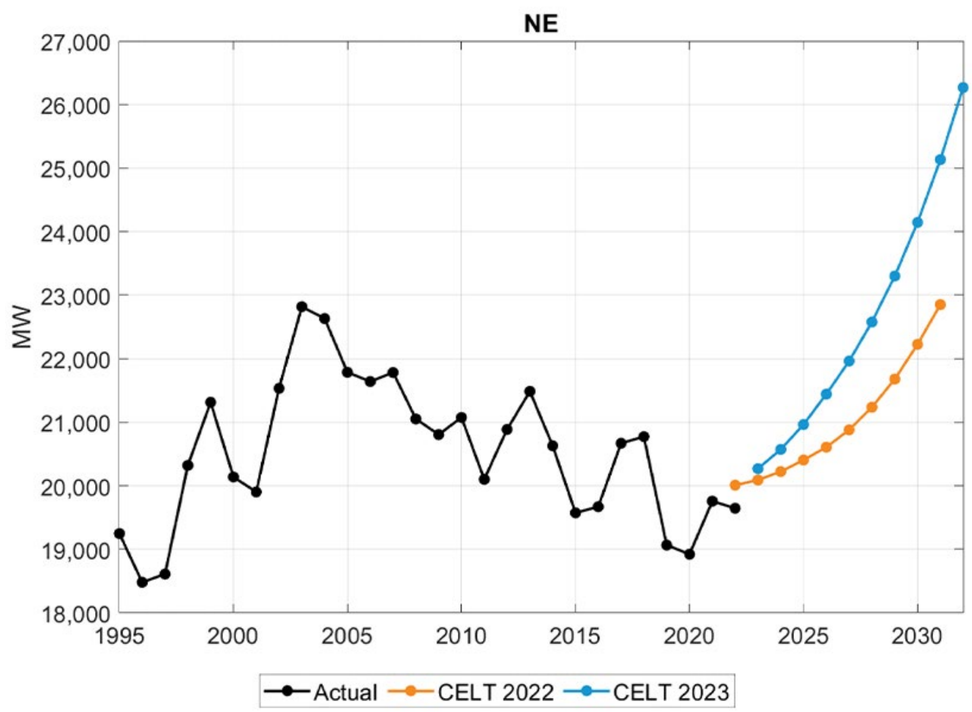
The updated forecasts are part of ISO-NE's annual Capacity, Energy, Loads and Transmission (CELT) *report*, which projects electricity demand over the next 10 years. They are used by the RTO to help with transmission planning, determining resource adequacy requirements, evaluating the reliability and performance of the grid, and coordinating maintenance.

The most significant changes for this year's projections related to updates in the methodology of forecasting electrification across the region, with major increases in the projected demand from electrified heating and transportation compared to the 2022 report.

The RTO boosted its projection for winter transportation demand for 2031 from 1,497 MW to 2,820 MW, while the summer projection increased from 1,082 to 1,927. The 2031 winter heating demand projection increased from 1,831 MW to 2,521 MW.

For the heating projection, this year's report looked at electrification within the commercial building sector, which was not included in last year's, based on extensive data from the National Renewable Energy Laboratory.

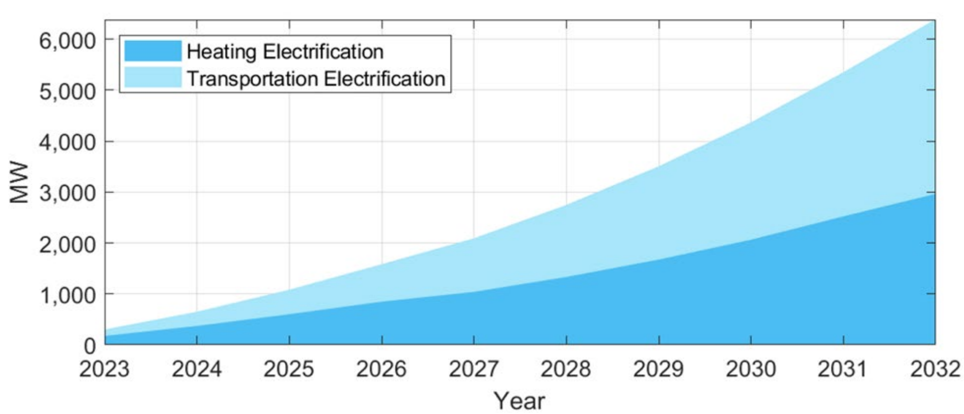
The transportation demand increase reflects the myriad new federal, state and local policies aimed at spurring the transition to electric vehicles. The figure was based on input from state regulatory agencies to assess the extent to which nonmandated electric vehicle targets will be met. The modeling assumes all state EV adoption mandates will be met.



Winter peak net load forecast: 2022 vs. 2023 projection | *ISO-NE*

The RTO also adjusted its projections to better account for the effect of cold weather on EVs.

"Energy and demand impacts of personal [light-duty vehicles] were revised to more dynamically incorporate the impacts of weather," said Victoria Rojo, lead data scientist of load forecasting and system planning for ISO-NE.



The projected increase in demand from electrified heating and transportation | *ISO-NE*

Peak demand is calculated using historical weather data for the winter and summer weeks with the highest typical demand. The RTO calculates a gross load forecast — which does not account for the impacts of energy efficiency programs or behind-the-meter solar — as well as a net load forecast, which subtracts these factors from the gross load.

ISO-NE increased its winter gross peak demand for 2031 by about 7% compared to the previous report and increased its summer projection by about 2%. The winter net peak projection for 2031 is approximately 10% higher than the 2031 projection from the previous report, while the summer net peak projection is about 5% higher than that from the previous report.

ISO-NE now projects net summer peak demand to increase to 26,505 MW in 2031, compared to the 24,605 MW the RTO projects for this summer. For net winter peak demand, ISO-NE projects 25,133 MW in 2031, compared to 20,269 MW for this winter.

The data indicate that winter peak load will grow faster than summer peak load and that winter peak load could pass summer peak load in the coming years. ■

MISO News

FERC Accepts MISO's Pledge for Annual Capacity Ratio Calculation

MISO's Dec. Calculation Error Led to Undervalued Planning Resources

By Amanda Durish Cook

MISO control room | *MISO*

FERC last week accepted a MISO tariff revision that promises an annual update of unforced capacity-to-intermediate seasonal accredited capacity ratio the RTO uses to determine supply ahead of its capacity auction (*ER23-1223*).

The ratio disrupted MISO's first seasonal capacity auctions and delayed the opening of its offer window by about a month. (See *1st MISO Seasonal Auctions Yield Adequate Supply*.)

FERC said the grid operator's pledge to calculate the ratio on an annual basis is reasonable and "provides greater notice to market participants regarding the timing" of its calculation.

"We expect that the schedule MISO develops with its stakeholders will incorporate sufficient time to work with market participants to validate and confirm [seasonal accredited capacity] values before finalizing the ratio," the commission said. "We encourage MISO to continue working with its stakeholders to improve its processes from lessons learned."

The grid operator's December calculation of the systemwide ratio in December produced an incorrect value. A computer error that counted previously excused maintenance outages against some planning resources undervalued their contributions.

This year, MISO and its Independent Market Monitor decided against reworking the ratio ahead of the spring capacity auction. They reasoned that the oversight wouldn't harm reliability, there wasn't enough time to rerun numbers, and market participants had already relied on the inaccurate ratio to enter bilateral supply contracts outside of the voluntary auction.

However, FERC found MISO in violation of its tariff and issued a show-cause order that had staff rehashing the calculation and delaying its first seasonal capacity auctions. (See *FERC Terminates MISO Show-cause Order*.)

After the ordeal, the grid operator updated its tariff to state that it will calculate the ratio on a standardized timeline, despite the determination requiring multiple rounds of market participants' data submission and staff's review and confirmation. MISO said its pledge to run the ratio annually is part of its lessons learned in moving to a seasonal capacity environment. It didn't specify when it plans to publish the ratio, saying it will settle on dates with stakeholders and include them in a business practice manual.

Commissioner James Danly said in a partial dissent that MISO should commit to a more specific timeline in its tariff and name dates.

"Given that there is so much at stake in the inputs to the Planning Resource Auction (PRA), the date of the annual establishment of the systemwide ... ratio for each planning year is fundamental to the mechanics of the market," he wrote. "This ratio ultimately informs load serving entities and resources of their accredited capacity in advance of the [PRA]. While there could be debate on this, I believe that the rule of reason compels us to require the date's inclusion in the tariff rather than the business practice manual." ■

MISO News

Experts Urge MISO to Consider New 765-kV and HVDC Lines

DNV Executive Notes VSC-HVDC Use in Europe for Climate, Reliability

By Amanda Durish Cook

CARMEL, Ind. — MISO's future is all but certain to contain more 765-kV and HVDC transmission lines, experts predicted during a special two-day meeting of the Planning Advisory Committee last week.

"The magnitude and scope of possible system challenges point to the need for a higher-voltage, higher-capacity superhighway or backbone of either 765 kV or HVDC," said Energy Systems Integration Group's James Okullo, citing the volatile ramping needs, increased congestion, larger energy transfers and voltage stability issues the resource transition will bring.

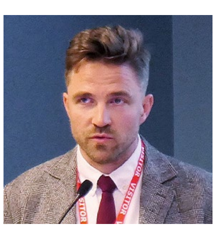
He pointed out that MISO is planning for a system with 80% annual renewable penetration within 20 years.

Multiple experts said MISO could use grid-forming voltage-sourced converter (VSC) HVDC lines and include them in the second portfolio of its long-range transmission planning (LRTP) effort. They praised VSC-HDVC's ability to deliver power-flow control, inherent reactive power and voltage support, dynamic stability, and synthetic inertia, and its potential to provide black start system restoration.

MISO planners have said they're not ruling out recommending a 765-kV or HVDC line in the second LRTP portfolio. (See *MISO: Long-range Tx Needed for 369 GW in Interconnections*.)

"VSC today is not as exotic a thing as it was 15 years ago, and with good reason," Minnesota Power's Christian Winter said.

Winter said VSC-HVDC is "uniquely suited for the clean energy transition" because it can move power across long distances while supplying ancillary services. He also said VSCs on the receiving end of transfers can function like dispatchable power plants and can be placed where retiring baseload generation is located.



Power System Advisory Vice President Cornelis Plet | *© RTO Insider LLC*

Cornelis Plet, vice president of power system advisory at DNV, said VSC-HVDC is becoming "the technology of choice" in European countries to achieve reliability while meeting ambitious climate goals. It allows the connection of different synchronous zones and can connect remote loads and remote generation. Europe is finding HVDC technology so useful that total installed HVDC capacity will more than triple in the next decade, he said. While the continent is so far building point-to-point lines, an overlay grid of HVDC lines will realize the full benefits.

VSC converters | *Siemens Energy*

VSC has become the "workhorse" of HVDC lines, and the use of line commutated converter technology is disappearing, Plet concluded.

Brattle Group Principal Johannes Pfeifenberger said MISO is "in the best position to take advantage" of VSC-HVDC as it plans its second LRTP portfolio.

"Tranche 2 is the opportunity for MISO to get its feet wet and offers a unique opportunity for MISO to gain the necessary planning, market integration and operational experience with VSC-HVDC technology for possible larger-scale future deployments," he said.

Pfeifenberger said Europe has discovered that VSC is "so compelling in what it can do" and has cemented itself as the dominant converter technology. He said grid planners struggle with placing a value on the resilience that HVDC can deliver. A well placed 2,000-MW HVDC line would help Texas address its AC stability limits when it transfers power from the western portion of the state.

"It's future-proof in a way that would be very expensive to address with AC technology," Pfeifenberger said. He recommended that MISO adapt its markets to be able to dispatch HVDC lines to capitalize on the "incredible advantage" of alleviating congestion by controlling power flows.

American Transmission's Bob McKee, representing MISO's transmission owners, said the RTO's current 240-GW interconnection queue shows the fleet transition is gearing up. He said he was delivering a "call to action from the TO sector" and encouraged MISO to "be bold" in its planning and consider all transmission solutions.

"I think Winter Storm Uri and Winter Storm Elliott are fresh in our minds, and we realize the importance of a robust transmission system," McKee said.

McKee also said electrification "just isn't coming; it's already here."

"This is our opportunity to identify a set of facilities that will fit our needs," he said. ■

MISO News

MISO Puts 2 Tx Planning Improvement Suggestions on Hold

By Amanda Durish Cook

CARMEL, Ind. — MISO last week said it will salvage two to-do items from its effort a few years ago to better link up interconnection trends with annual transmission planning.

But the RTO warned that it will likely be years before it has the time to work out possible solutions for them.

The grid operator will keep two unaddressed stakeholder *suggestions* on hold: one to develop more robust analyses to recommend alternative projects to transmission owners' proposals, and another to devise a method to evaluate network upgrade projects for potential regionally allocated market efficiency projects.

Jeanna Furnish, MISO's director of expansion planning, said the two items are the only ones left unaddressed from the project it launched a few years ago to better match its annual transmission planning with the projects that generation developers submit to the interconnection queue. (See *MISO Begins Bid to Merge Tx, Queue Planning*.)

Since then, MISO has begun recommending and planning portfolios under its long-range transmission planning (LRTP) initiative, satisfying most of the endeavor. The RTO had suggested dropping the listing altogether as part of a cleanup of old stakeholder recommendations, but the Environmental Groups sector protested the deletion. (See *MISO Proposes Review of Improvement Ideas' 'Parking Lot'*.)

"At this time, we don't foresee having enough resources to be able to work on this until at least 2025," Furnish warned stakeholders at the Planning Advisory Committee meeting Wednesday. She said MISO's LRTP effort is already dominating the manpower needed to create an alternatives or evaluation process. It will consider the recommendations "inactive" until 2025.

Earlier in spring, the Sustainable FERC Project's Natalie McIntire argued the concerns that gave rise to MISO's retired Coordinated Planning Process Task Team (CPPTT) remain:

| © RTO Insider LLC

"MISO has no process to evaluate whether a transmission project required for either generator interconnection or a transmission service request also meets the criteria" of a baseline reliability project or market efficiency project. She argued that the RTO's tariff demands due diligence across its planning practices.

McIntire said she believes MISO has a duty under FERC Order 1000 to look for more cost-effective transmission alternatives that combine planning needs. But she said MISO simply assures stakeholders it is already doing that, though not much is known about the process.

"MISO must comply with its tariff and create a process by which projects can be evaluated to see if they meet the criteria of other project types," McIntire said.

The RTO closed out the CPPTT in 2020 when it began working on the first of its LRTP portfolios. At the time, it reasoned that the hefty, comprehensive transmission portfolios would cover the need for an examination into the depth and interconnectedness of its transmission planning amid the clean energy transition.

McIntire said her concerns would be assuaged if MISO committed to conducting the LRTP on a regular basis, but the RTO has not said it has a frequency in mind for long-range planning. She also said LRTP studies take multiple years to finish, making a cadence difficult to establish. Interconnection requests in the intervening years between LRTP studies could turn up network upgrades that would be better suited as regional or reliability projects, she said.

MISO's newly revived Stakeholder Governance Working Group is working on how it can have a structured process for closing out stakeholder-submitted ideas for improvement. Today, the RTO doesn't have a formal process for removing stakeholders' recommendations from its to-do list. ■

Midwest news from our other channels

Michigan County Approves Moratorium On Major Renewable Projects

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MISO News

MISO Wants Tougher Obligations on Queue Entry and Exit

By Amanda Durish Cook

MISO's Andy Witmeier | *© RTO Insider LLC*

CARMEL, Ind. — Faced with an exponential rise in interconnection requests, MISO last week announced that it is aiming to make its queue a more exclusive club through new rules.

The grid operator said it needs stricter requirements for developers to enter and exit the generator interconnection queue so it can make its studies more manageable.

"We need to govern the rules for exit and entry. We believe that will improve our queue," MISO's Andy Witmeier said at the Planning Advisory Committee's meeting Wednesday. He said that if MISO imposes more requirements on land ownership, restricts the conditions for penalty-free withdrawals and increases some fees, it will shrink annual queue entrant classes.

Witmeier said 2022's 171-GW queue class alone eclipses the typical systemwide 123-GW summer peak. MISO is bracing for another record-setting queue volume in 2023.

"It's significantly more generation than would ever be built in MISO over the next few years, and there are concerns over how to study it," Witmeier said. "More requests mean more points of interconnection and more study. There are more [hypothetical] overloads because of the sheer amount of capacity. That requires more engineering study."

If MISO could cut down on the amount of "speculative requests," it would result in study assumptions that better resemble the actual future dispatch, he said. "Smaller queue sizes mean faster results."

Witmeier said it currently does not cost that much to enter MISO's queue. And he said the RTO's penalty-free withdrawal policy allows most interconnection customers who withdraw requests to get most of their money back. The $4,000/MW first milestone payment MISO requires of its projects is a "low bar" and represents only about 4% of the RTO's approximate $100,000/MW financial feasibility threshold for the cost of network upgrades, he said. MISO's deposits were last upped in 2018 and need to be increased, he said.

MISO will propose a package of alterations at the Planning Advisory Committee meeting in July, Witmeier said. After that, the RTO hopes to file a proposal with FERC in the third quarter and receive approval with enough time before year-end to close the 2023 queue application window. The RTO said it will keep the deadline open-ended until it receives FERC approval on the changes.

MISO was already planning to postpone the application deadline for its 2023 cycle of projects past its usual September cutoff. (See *MISO: No Deadline Yet for 2023 Queue Applications*.)

Witmeier said MISO is aware that enacting stricter requirements on queue entry can be perceived as it hindering generation development. But he said the real impediment to generation development is the flood of requests — with uncertain project plans among those — that bog down the study process and shift network upgrade costs to other projects. He added that only about 20% of the interconnection requests that enter the queue ever become realized generation projects.

Brattle Group Principal Johannes Pfeifenberger asked if MISO was worried that by restricting the entry of interconnection customers, it will raise the costs of network upgrades because there are fewer generation developers to split them.

Witmeier said he does not believe MISO will encounter that problem because it performs adequate backbone transmission planning through its long-range transmission plan (LRTP) portfolios. He said MISO avoids using its interconnection queue as a means to build major transmission. He also said the first, $10 billion LRTP portfolio likely drove up interconnection requests in 2022.

Witmeier said he plans to reach out to stakeholders to get their ideas on how to make queue entrances and exits less heavily trafficked.

The Sustainable FERC Project's Natalie McIntire said she is concerned that MISO plans on privately discussing the changes with individual stakeholders.

"I think there needs to be a fairly lengthy stakeholder dialogue on this, and not behind closed doors," McIntire said.

"We need to be able to work expediently on this. This is not a full-fledged redo of the queue," Witmeier responded. "However, because we have so many requests, we have issues with speed and cost certainty. So, we have to adjust those rules."

Witmeier said MISO's penalty-free withdraw provision is akin to being able to play see the "river" card in Texas hold'em poker without matching a bet. "That's just not right." ■

PJM News

PJM Capacity Auction Week away with No Answer on Delay

By Devin Leith-Yessian

PJM's scheduled date for the 2025/26 Base Residual Auction (BRA) is next week, and it still does not have an order from FERC on whether it will be permitted to delay the auction (ER23-1609).

The RTO on April 11 asked FERC for permission to indefinitely postpone the auction, currently scheduled for June 14, to allow it to implement market rule changes now under stakeholder consideration through the Critical Issues Fast Path (CIFP) process. The following three auctions would also be delayed under the proposal, with the schedule returning to its normal three-year advance time frame for the 2029/30 BRA in May 2026.

Under Federal Power Act Section 205, if FERC does not issue an order within 60 days, the filing will go into effect by operation of law. That period ends on June 10, the date on which PJM asked that the changes go into effect. The RTO had said that if the commission does not approve the filing prior to June 10, it will proceed with the auction as scheduled.

PJM had requested expedited consideration with the hope of receiving an order by May 19, which the RTO said would allow it to provide market participants with advanced notice of any delay to the auction and allow them to focus their efforts on the CIFP process.

The filing did not include exact auction dates for the four delayed auctions to give PJM flexibility to incorporate any changes arising from the CIFP process, but it did include an illustrative timeline. Under that timeline, the 2025/26 BRA would be held in June 2024, and the following three auctions would be held every six months after.

Steve Lieberman, American Municipal Power's vice president of transmission and regulatory affairs, said market participants are having to make decisions about their offers with little clarity about what the future of the auction holds, making it difficult to properly manage where they should focus their time and resources.


Mark Takahashi, PJM Board of Managers | *© RTO Insider LLC*

"I think we're all in a tough place here, and it would be good to get some direction one way or another from FERC," he said. "Nobody in our markets likes uncertainty."

Comments submitted to the commission on the filing were split, with opponents arguing that a delay would disrupt state procurement auctions and undermine the goal of giving confidence to generation owners about their potential revenues. Opponents also said that the filing was based on speculation that the CIFP process will yield a proposal ultimately accepted by FERC. They argued that the proposal was overly broad by not including the specific dates to which PJM would delay the auctions.

"In theory and practice, it's clear that shortening the lead time between the auction and the delivery year helps incumbent resources and muddies the market signal needed to incent new generation," the Organization of PJM States Inc. protested.

Supporters argued that delaying the auction would allow the changes to the capacity market to be implemented with the aim of improving the accuracy of the price sent by the auction.

"While P3 has not traditionally supported delaying important [capacity] auctions, given the need to conduct future capacity market auctions under just and reasonable rules, P3 supports PJM's filing as an unfortunate necessity," the PJM Power Providers (P3) Group said in its comments. "The commission's approval of the PJM filing will allow PJM to address the capacity market concerns and reliability issues in PJM so that auctions for the delivery years 2025/26 and beyond will appropriately send price signals to capacity resources to remain on, retire from or enter the market."

PJM defended its filing by stating the impact of December 2022's Winter Storm Elliott and reliability concerns found in its February "Energy Transition in PJM" white paper highlight the need to send price signals that will encourage the generation needed for resource adequacy through 2030.

"While PJM does not take any delay of the capacity auctions lightly, on balance, a limited delay of the upcoming [Reliability Pricing Model] auctions is necessary and appropriate at this time given the region's recent experience with Winter Storm Elliott and the imminent reliability concerns identified in the Energy Transition '4R' white paper," PJM said in a May 10 reply comment. "This delay is necessary because sending the correct capacity market price signal is better than continuing to establish inaccurate price signals in an attempt to rush the auction and establish a clearing price for the capacity auction as early as possible."

The Sierra Club and Citizens Utility Board commented that although they do not have an opinion, they believe the white paper had a flawed outlook on resource adequacy over the coming years. In an affidavit, economist James Wilson argued that it ignored the price signals that future capacity auctions would send as resources retire to construct new generation.

"The [white paper's] model fails to account for the core feature of the PJM capacity market intended to anticipate and address future potential shortfalls: the capacity market price as determined by PJM's sloping demand curve," the comments state. ■

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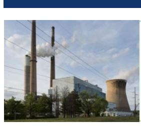

W.Va. Coal-fired Plant May Experiment with Hydrogen to Avoid Demo

NetZero Insider

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PJM Urges FERC to Deny Winter Storm Complaints

RTO Argues they Would Undermine Key Aspects of Reliability

By James Downing

PJM last month issued its first official responses to an onslaught of complaints at FERC from generators over Capacity Performance charges during the cold snap over the holidays, arguing that they knew what risks they were facing when they took capacity payments.

The winter storm led to many nonperformance charges Dec. 23 and 24, which have led to 12 separate complaints filed at FERC. PJM responded to seven of those May 26.

The storm, also known as "Elliott," led to outages in neighboring grids and nearly did in PJM, though its operators were able to keep the lights on despite the nonperformance of many generators.

"These failures could have had life-and-death consequences had events played out differently," the RTO said. "As it was, PJM operators preserved reliability while contending with unprecedented difficulties and uncertainties that were exacerbated by complainants' nonperformance. In short, the lights stayed on despite extremely stressed conditions brought about by capacity resources failing to meet their obligations."

PJM filed responses to the "Nautilus Entities" (EL23-53); generators in the ComEd zone (EL23-54); a coalition of capacity resources including Competitive Power Ventures and Talen Energy (EL23-55); Lee County Generating Station (EL23-57); Sun Energy (EL23-58); Lincoln Generating Station (EL23-59); and Parkway Generation Keys (EL23-60), though comments came in to all 12 dockets.

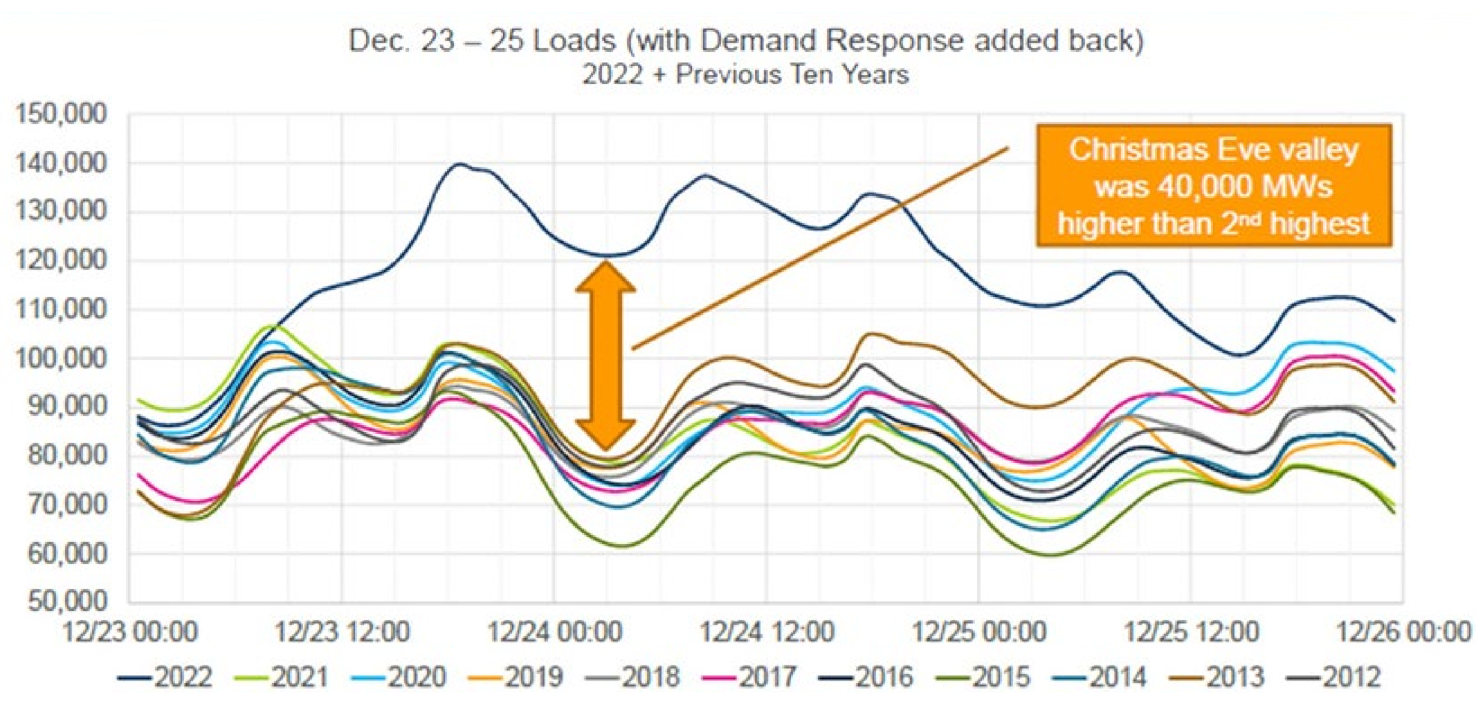
The only ways generators can avoid nonperformance charges during emergency events are if they are on a planned outage approved by PJM or the RTO did not schedule them. CP holds resources with restrictive operating limits to the same standards as those without them. Natural gas generators are responsible for procuring natural gas deliveries despite pipeline outages.

"Capacity market sellers should assume that their resources will be needed, at a minimum, any time the PJM region is under a declared emergency for capacity shortages," PJM said. "If capacity market sellers need to purchase natural gas and self-schedule to ensure that their capacity resources can be available when needed, then sellers of gas-fueled capacity resources should engage in such forward-looking behavior."

PJM argued that the generators' failure to perform cannot be excused by claiming the grid operator's actions were invalid, by asserting there was no emergency or by arguing that their performance was not actually needed to address that emergency.

"Complainants urge the commission to become the Monday morning quarterback and super-operator of the grid, which are both roles the commission has been careful to avoid in the past," PJM said. "The regulatory process will rapidly unwind with perpetual litigation, and reliability will be undermined, should the commission choose to disregard the real-time flexibility regional transmission organizations must have to manage emergencies and to substitute its judgment with the luxury of perfect hindsight."

Some of the complaints criticized PJM for helping neighbors that were shedding load; siding



A graph PJM produced showing how much higher demand was compared to historical norms during the late December winter storm. | *PJM*

PJM News

with those arguments would chill cooperation between neighboring systems in future emergencies, the RTO argued.

The group of generators in ComEd's territory argued that their islanded section of PJM lacked any real emergency, but the RTO said they do not get to determine when emergencies exist. PJM declares emergencies, and the 6,110 MW of generation in northern Illinois the generators failed to provide represents 21.5% of the reserves it was relying on during the storm, it said.

"PJM recognizes that there remain valid issues associated with the lack of synchronization between the natural gas nomination cycles and the real-time nature of electric system dispatch," the RTO said. "This lack of synchronization is not new and existed at the time these unit owners submitted their bids into the capacity Base Residual Auction."

One of the recommendations from FERC and NERC's joint report on the February 2021 winter storm that knocked out power in Texas and surrounding states was to improve electric-gas coordination. The North American Energy Standards Board has been assigned that work.

Concerns over electric-gas coordination are national in scope, and FERC should not try to resolve them via proceedings on one winter reliability event in the Eastern Interconnection, PJM said.

Other Parties Weigh in

Sierra Club filed a response to several of the complaints, noting that they arose from the first application of the CP rules, which are also the subject of stakeholder proceedings looking into future changes. The organization said it is important to remember that a central objective of the rules was to get generators to change their behavior and investment decisions in ways that would improve reliability.

"Taking on a capacity obligation in PJM — in exchange for hundreds of millions of dollars in revenue — is not and should not be a risk-free enterprise," Sierra said. "For the Capacity Performance system to work, suppliers must be held to the rules they agreed to when taking on and accepting payments for capacity obligations."

Sierra had some sympathy with one of the complainants: SunEnergy1, a solar farm that wants relief going forward to excuse solar from the risk of nonperformance when the resource has little availability — and is paid less to reflect that. But natural gas generators should not be excused from the penalties because of "the inflexible gas supply arrangements" they prefer to make.

"Where penalties cannot drive better performance, a resource's nonperformance should not incur penalties," Sierra said. "In contrast, penalties should apply where resources can take steps to improve performance, such as weatherizing equipment or procuring gas in order to fulfil their capacity obligations — as the commission concluded after considerable discussion back in 2015."

Constellation Energy Generation argued that FERC should dismiss the complaints because customers in PJM pay billions per year to ensure generator availability and the suppliers who failed to show up during Elliott knew what they were risking before the storm.

"PJM's tariff is clear, unambiguous and strict: Penalties are mandatory when a CP resource fails to meet performance expectations during an emergency action declared by PJM," Constellation said. "The exceptions are intentionally narrow."

While generators face risks, they are allowed to include them in their capacity offers, along with the costs of investments to mitigate them. Generators also have the option to only participate in the energy market and avoid CP entirely.

"With full knowledge of the risks and obligations of accepting a capacity commitment, complainants bid into the capacity auction, received capacity commitments and cashed checks from ratepayers," Constellation said. "But when their capacity was needed, they failed to deliver. Now they don't want to pay the resulting penalties."

Vistra told FERC that the markets performed as designed during Elliott, with some generators underperforming and others overperforming, while PJM maintained reliability.

"The complaints invite the commission to second-guess PJM's operational decisions during emergency conditions and/or disrupt the market outcomes designed to flow from those decisions pursuant to the filed rate," the company said. "Vistra respectfully submits that both invitations are perilous and, to maintain both the integrity of the market and the proper incentives needed for system reliability, the commission should view the complaints with skepticism."

Even if FERC sides with the complaints, it should affirm the continued validity of the CP rules, Vistra said. ■

PJM News

PJM Stakeholders Complete 2nd Phase of CIFP

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM last week wrapped up the second phase of its Critical Issue Fast Path (CIFP) process to address resource adequacy concerns with two meetings about proposed changes to the RTO's capacity market.

At May 30's meeting, Constellation Energy *proposed* shifting to a prompt capacity auction held closer to the corresponding delivery year; the Consumer Advocates of the PJM States (CAPS) *discussed* states' priorities and concerns around overhauling the Reliability Pricing Model (RPM); and American Municipal Power (AMP) *presented* changes to its conceptual design.

PJM also *provided* additional information about its contemplated switch to an expected unserved energy (EUE) model for measuring risk. (See *PJM Presents Lessons Learned from Elliott, More CIFP Presentations*.)

Thursday's meeting saw presentations from the Natural Resources Defense Council on *creating* a seasonal capacity market; a former market design architect from ISO-NE providing *information* on a conceptual market design; Cornerstone Research's Roy Shanker on his *concerns* about the current market structure; and Vistra on *creating* a credit market to value resource upgrades providing added reliability.

Stakeholders will begin developing formal packages during the third CIFP stage beginning June 14, when PJM will present its proposal.

Constellation Proposes Tighter Auction Schedule

Constellation's Bill Berg said many of the inputs to the capacity auction could be more accurate and price signals could be improved if PJM holds capacity auctions six months to a year in advance of a delivery year. The status quo of holding auctions three years in advance makes it difficult to accurately forecast load and for generators to be sure whether they can procure firm fuel supply — a parameter PJM is considering having generators report prior to the auction.

Several stakeholders said the rationale for holding auctions three years in advance has been to allow the reference resource, currently a combined cycle generator, to be built between the auction clearing and the start of the delivery year to shore up capacity procurement shortfalls. Berg said investors monitor resource needs regardless of auction timing and are likely to make investments if they believe a region will be short on generation, regardless of auction timing.


Consultant Roy Shanker | © *RTO Insider LLC*

Ryann Reagan, of the New Jersey Board of Public Utilities (BPU), questioned how a shortened time frame would interact with state retail auctions, noting that New Jersey has a three-year forward capacity product.

Berg responded that there's a balance between price certainty and accuracy, which he believes is best weighed in favor of accuracy. Resources participating in state auctions with a longer lead time than a prompt auction would have to estimate PJM capacity prices when participating in state markets.

Constellation also suggested that compensating capacity resources at the end of the delivery year could improve performance incentives and lead to higher collections of any performance penalties the generator may accrue over the year.

While Berg said his company supports PJM's proposal to set a minimum number of performance assessment intervals (PAIs) each year, market sellers must be able to reflect all risks and avoidable costs in their capacity offers.

CAPS Executive Director Greg Poulos said expanding the costs included in capacity market offers could run afoul of FERC's 2021 order on PJM's market seller offer cap (MSOC). (See *Judges Skeptical of Capacity Sellers in PJM Offer Cap Dispute*.)

"This seems like a dead-end to us because FERC already ruled on this," Poulos said.

Berg also urged stakeholders to consider changes to the energy market, where he said PJM has put the onus of addressing reliability risks posed by forecast uncertainty and resource constraints, but it has had to resort to out-of-market actions to maintain operational reliability.

CAPS Outlines Advocate Concerns

As stakeholders discuss an overhaul of the capacity market, Poulos said state advocates are concerned about the Base Residual Auction (BRA) schedule, as well as how to ensure that market power is kept in check, performance incentivized and proper price signals are sent.

Advocates also lack firsthand insight into how the markets functioned during the December 2022 winter storm, also known as Elliott, making it difficult for them to evaluate proposals being discussed in the CIFP process, he said.

When considering changes to Capacity Performance (CP) penalties, Poulos said, it's important to balance having penalties so high that generators risk bankruptcy after one event and having them so low that they don't lead to better performance during future emergencies. Though performance was an issue during both the 2014 polar vortex and Elliott, he said CP likely did lead to increased readiness.

"The goal is not to bankrupt people — that is not helpful — but if you can't perform, I don't know what your value in this mix is," Poulos said.

AMP Presents Revised Proposal

AMP revised the proposal it has been building throughout the CIFP process, which would replace the CP construct with a process for testing generators and penalizing them if they are not able to meet the amount of capacity they cleared. The changes aired May 30 would marry that concept with the proposed reworking of the performance penalty structure endorsed by the Members Committee last month but rejected by the PJM Board of Managers.

The revisions would shift the penalty rate and annual stop loss from being based on the net cost of new entry (CONE) to the BRA clearing price. AMP championed the language in the MC as a way of aligning market sellers' capacity revenues with any penalties they're assessed, while retaining an incentive to perform throughout the year.

Opponents of the language when it was before the MC argued that it would pose a reliability

PJM News

risk by cutting the penalty rate and stop loss by 90% without adding to requirements like winterization requirements.

PJM Presents Risk Modeling Analysis

PJM presented preliminary results of its analysis on the impact of switching to a reliability requirement based on an EUE model, which measures the amount of load that would go unmet during outages. The RTO currently uses a loss-of-load expectation (LOLE) model, which is a count of the number of outages expected. (See *PJM, Stakeholders Present Initial Capacity Market Proposals to RASTF*.)

In past CIFP discussions, PJM has proposed shifting the metric as part of its effort to improve risk modeling.

PJM's analysis found that the EUE equivalent to the current one-day-in-10 reliability threshold would be around 1,800 MWh of lost load, with 96% of the outage risk concentrated in winter. Under the LOLE model, PJM estimates that 78% of the risk is in the winter, with the remainder being in summer.

PJM's Patricio Rocha Garrido said winter outages tend to last longer and lead to more lost load, which he said is captured as increased winter risk through the EUE model.

The largest summer supply loss represented in the data was about 15 GW in July 2012, Rocha Garrido said, while 46 GW of generation was lost during Elliott.

James Wilson, a consultant to state consumer advocates, argued that the change would exaggerate risk and said that if being conservative in resource adequacy is a goal, that should be done through policy rather than modeling. He noted the analysis shown May 30 doesn't account for climate change, which he said is likely to reduce the amount of risk in winter relative to summer by leading to warmer temperatures in both winter and summer.

Pat Bruno, PJM | © *RTO Insider LLC*

PJM's Pat Bruno said the RTO plans to continue improving the modeling, including by incorporating climate change into the data. He added that PJM had run sensitivities that found that climate change was unlikely to move the needle much for the type of modeling under discussion. Future analysis is also likely to include the impact on the installed reserve margin (IRM) and resource accreditation.


Patricio Rocha Garrido, PJM | © *RTO Insider LLC*

Bruno said the planning and market structures are currently based on an assumption that risk is concentrated in the summer, but the analysis suggests that a rethinking of those rules may be needed to maintain future reliability.

Vistra Presents Credit Market for Reliability Upgrades

During Thursday's CIFP meeting, Vistra presented a proposal to create tradable credits to be awarded to generators that make investments to increase their performance, which would also raise their capacity accreditation.

Erik Heinle, Vistra's director of PJM market policy, said that such investments may not lead to more capacity clearing in the BRA; however, it will increase a generator's performance obligation, making it more likely to be subject to penalties and less likely to receive bonus payments.

The credits would be tradable in a PJM market and could be used by a buyer to excuse a performance shortfall equal to the increased capacity accreditation. PJM would create weekly risk assessments based on factors such as load and intermittent forecast variation, outages and fuel supply surveys, which buyers and sellers could use to determine their estimates of being subject to penalties.

Credits would only be awarded for facility upgrades on a list PJM would create during each quadrennial review.

Heinle said the proposal would add a financial product to allow generators to mitigate their non-performance risk, while still retaining an incentive to invest in upgrades.

Vitol's Jason Barker said similar transactions exist today through bilateral transactions or within larger companies that maintain generation portfolios containing resources that can offset each other's risks. Heinle said a PJM marketplace would increase transparency and improve price discovery.

Vistra's Muhsin Abdur-Rahman said the proposal could also reduce the Capacity Performance quantified risk (CPQR) component of generators' capacity offers to correspond with the reduced risk.

PJM Capacity Market Fuel Assurance Accreditation Concept

PJM's Brian Fitzpatrick discussed a possible addition to the proposal being crafted by PJM that would create tiers of fuel security paired with the effective load-carrying capability (ELCC) model for each level. The proposal is currently focused on natural gas but would

PJM News

likely be expanded to other resource types as well.

Generators participating in the BRA would be required to indicate whether they will have dual fuel, single fuel with firm supply or single fuel without firm supply.

Fitzpatrick said the proposal is meant to help identify a lack of capacity on a gas pipeline or encourage greater fuel subscription to incentivize pipelines to expand, rather than creating another penalty structure for gas generators.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said fuel supply needs to be looked at holistically, incorporating issues being addressed by the Electric Gas Coordination Senior Task Force and examining other fuel types as well.

NRDC Proposes Seasonal Market

The NRDC presented a series of priorities it believes CIFP proposals must address around managing resources' performance risk, including accurately accrediting resources and avoiding double-penalizing resource characteristics through CP and accreditation.

Tom Rutigliano, senior analyst for the NRDC, said accounting for resources' characteristics through accreditation is the most effective option, rather than creating eligibility criteria for capacity resources, penalties or combining approaches. He supported PJM's proposal to expand the use of the ELCC model to all resource types on the basis that it can weigh generators' performance against the disparate risks the grid faces for each hour throughout the year.

Creating a system like ELCC to evaluate multiple gas generators fueled by a single pipeline to determine the marginal capacity value could also improve accreditation by revealing whether a pipeline is likely to be oversubscribed during an emergency, he said.

Though he said it would likely be topic to explore after the CIFP process, Rutigliano suggested moving to a seasonal capacity market to resolve some of the issues that expanding ELCC would not address, including variable transmission constraints, price signals incentivizing winterization investments, and treatment of planned and maintenance outages.

Rutigliano said that subjecting resources, particularly intermittent ones, to penalties for underperformance owing to characteristics already priced into their accreditation amounts to penalizing them twice. During Elliott, he said, wind and solar both performed as expected, but solar resources were generally assigned penalties, while wind resources receive bonuses based on attributes included in their ELCC analyses.

Shanker Highlights Concerns with Market Structures

Consultant Shanker presented a series of suggestions for stakeholders to consider throughout the CIFP process impacting all proposals, including:

- how the must-offer requirement relates to auction planning parameters and performance obligation during PAIs;
- how power exported from PJM during emergencies affects the balancing ratio;
- who is the beneficiary of export premiums if the capacity benefit of ties is removed;
- how many of these issues result in hidden future transmission charges; and
- how stochastic generation and common mode outages could cause locational impacts adverse to reliability.

The forecast pool requirement (FPR) and associated IRM are determined with the assumption that all resources holding capacity interconnection rights (CIRs) will offer into the capacity market; however, excepting intermittent resources from the must-offer requirement skews both parameters, Shanker said.

Shanker cited Independent Market Monitor studies showing that about half of such resources hold CIRs but have not been offering in auctions. Because the variable resource requirement (VRR) curve is derived from the FPR and IRM, this leads to overstatement of the reliability of the capacity procured through the BRA. He said the calculation of the capacity emergency transfer objective (CETO), capacity emergency transfer limit and locational deliverability areas' reliability requirements cause the same issue. The issue also raises market power issues regarding holding CIRs but not using them, he contended.

Shanker also said that many market components, including the FPR, IRM and CETO, incorporate an infinite transmission assumption, which can also lead to overstated reliability by not taking location and intermittency into account, causing additional hidden transmission costs.

Shanker also called for eliminating the capacity benefit margin (CBM) and capacity benefit of ties (CBOT) when determining PJM's reliability requirement in order to ensure the RTO can meet its own needs at a capacity price that matches the cost of resources required to reliably meet grid requirements. He noted that this should logically change the price of emergency assistance and that associated export revenues would flow to native load rather than into any potential penalty and bonus structures added to the current CP design.

Conceptual Capacity Market Exchange Presented

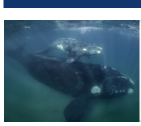
Dick Brooks of Reliable Energy Analytics presented how PJM could use an always-on capacity exchange (AOCE) with further development of the concept.

A former software architect of ISO-NE's forward capacity market clearing engine, Brooks said the project was developed as a strawman design for the clean energy transition and was being brought before the CIFP to demonstrate that other paradigms are being created.

The market would use a shorter auction advance timeline with capacity prices determined using an exchange and clearing price similar to day-ahead energy markets. Capacity resources would be approved by the RTO and enter offers into the market to be bid on by customers.

The RTO would continue to determine the total amount of capacity needed for a location and time, which the RTO would issue its own reliability bids to meet needs in the short or long term. Bids exceeding the total amount of capacity needed wouldn't be cleared to receive capacity payments. ■

Mid-Atlantic news from our other channels



NJ Legislators Probing Whale Deaths Hear No Clear Conclusions

NetZero Insider

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

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Reject PJM Synch Reserve Manual Change; RTO Overrides

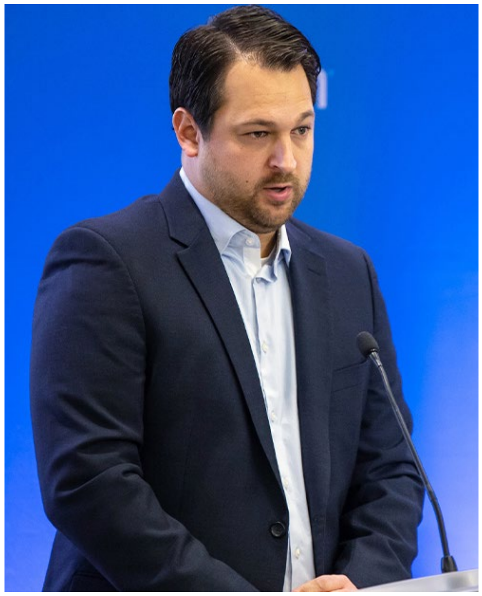
VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee voted 54% to reject *manual changes* that sought to clarify how the RTO can exercise unilateral power to increase the synchronized reserve requirement, with stakeholders opposed arguing that such action should require a FERC filing and doesn't address the root cause of underperforming reserve resources.

On May 11, PJM announced that it would be doubling the requirement, but the increase was removed May 16 and replaced with a smaller 30% increase May 19, which PJM Senior Vice President of Operations Mike Bryson said was done to reflect stakeholder feedback regarding the initial increase. (See "PJM Doubles Synchronized Reserve Requirement," *PJM OC Briefs: May 11, 2023*.)

The proposed language would have specified that "PJM may schedule additional contingency reserves on a temporary basis in order to meet the largest single contingency, as necessary to account for resource performance" to meet ReliabilityFirst requirements. Senior Vice President of Market Services Stu Bresler said it was hoped stakeholders would be in consensus with PJM but that PJM plans to move forward with implementing the manual changes and the 30% increase unilaterally.

The response rate from synchronized reserve resources fell by an average of about 20% following the implementation of an overhaul of the reserve market in October that consolidated the Tier 1 and 2 products, according to a previous *presentation* to the Markets Implementation Committee. Bryson said PJM has a responsibility to procure reserves that can match the largest single contingency the grid faces, and it is working with Independent Market Monitor Joe Bowring to identify other solutions to address the low performance, including possibly referring resources to FERC for tariff violations.

Senior Dispatch Manager Donnie Bielak said the poor performance could be responsible for a potential violation of NERC disturbance control performance standards during the December 2022 winter storm, when PJM took just over the 15-minute window to recover



Donnie Bielak, PJM | © *RTO Insider LLC*

from a drop in the area control error. The response rate has been stronger from former Tier 1 reserve resources, which were online through economic dispatch and able to increase output within 10 minutes, but PJM said their response will fall off in the future as their operations reflect that they are not receiving added compensation for that response above the going LMP.

The 30% increase is composed of 20% to account for the nonperformance, plus a 10% increase for uncertainty around the future response from uncommitted reserve (former Tier 1) resources. The increase amounts to a synchronized reserve reliability requirement of 2,080 MW, an increase of 480 MW. PJM's Phil D'Antonio said the 200% increase could be brought back if it is determined to be necessary to meet the contingency reserve requirement, but that PJM will not go above that mark.

Old Dominion Electric Cooperative's Mike Cocco said increasing the amount of reserves procured to account for underperforming resources is an "inelegant solution" and questioned what a long-term solution looks like. D'Antonio said PJM plans to bring a problem statement and issue charge around August.

Gregory Carmean, executive director of the Organization of PJM States Inc., said he believes the change would affect rates and thus requires FERC authorization, to which Bresler said the PJM tariff sets out a formula including synchronizes reserves and authorizes the RTO to set the reserve requirement.

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned if the response rate could be affected by an interaction between the October market change and PJM's software, data input or the ancillary service optimizer. He said it doesn't make sense that reserve resources aren't responding to LMPs but noncommitted resources are.

"There seems to be a mismatch between what you're describing and what's actually going on here," he said.

Presenting the Monitor's perspective on the proposed language, Bowring said he doesn't believe PJM has the authority to make the changes on its own and the focus should be on perfecting supply, rather than increasing demand. Resources providing synchronized reserves have stated to him that they have issues with the supply curve and that they're not able to provide what they're being committed and paid for. While he said the must-offer requirement needs to be enforced, which could include FERC referrals, that is not the optimal way of getting the desired performance.

Bowring cited as possible reasons for the low performance the accuracy of PJM's ramp rates, ambient rates, fuel availability, demand response performance, resources failing to follow dispatch, incorrect eco max and spin max parameters, and discontinuities in the offer curves.

Stakeholders Discuss Way Forward on Circuit Breaker

PJM *presented* a first read of its proposal to create a "circuit breaker" to limit high prices over an extended period, continuing deliberations on a topic that divided stakeholders and yielded a half dozen proposals before the frontrunners were rejected by the MRC in December. (See "Two Proposals on 'Circuit Breaker' Fail," *PJM MRC/MC Briefs: Dec. 21, 2022*.)

The proposal unveiled Wednesday was built off PJM's previous Package F, which was formed in the Energy Price Formation Senior Task Force and would administratively cap LMPs to $2,000 after PJM has been in an RTO-wide operational emergency, defined as a NERC Level 3 energy emergency alert (EEA) event, and shortage price is in effect because of manual load dump or a voltage reduction. The trigger also includes a step in which PJM will evaluate how activating the circuit breaker would affect reliability and will not implement it if any concerns are identified. The circuit

PJM News

breaker would end once PJM is no longer under EEA 2 or 3 conditions and the shortage pricing is no longer in effect.

PJM's previous proposal did not include an administrative review as part of the price cap trigger, and it would have terminated after a five-day period. Senior Director of Market Design Becky Carroll said the changes were made to ensure the circuit breaker didn't harm operations and would not end while an emergency was potentially ongoing.

"We really are concerned about creating adverse impacts to system operations, and we don't want to do that," she said.

Carroll said the proposal is still in flux, and additional details on components, such as when the circuit breaker would be triggered, could change by the time tariff language is drafted. Bresler said PJM plans to bring the language directly to the Board of Managers without a stakeholder endorsement, as the issue has already been brought through the full stakeholder process without being able to reach consensus.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said the impact of the February 2021 winter storm on ERCOT underscored the need to create a price cap for many advocates, and he encouraged PJM to consider how other regions have reacted. He also said PJM should consider the components in the joint stakeholder package, sponsored by ODEC, Southern Maryland Electric Cooperative and Northern Virginia Electric Cooperative, given that the PJM proposal never advanced to the senior committee level. The joint package and a competing proposal from Calpine were both rejected by the MRC on Dec. 21, while five other *proposals* did not advance from the EPFSTF. (See "Support for Circuit Breaker Remains Mixed," *PJM MRC Briefs: Oct. 24, 2022*.)

David "Scarp" Scarpignato said that under the status quo, the scarcity adder gives a buffer over the inflexibility of incorporating fuel costs into offers, which wouldn't be possible under the uplift provided by the circuit breaker based on those offers. Most generator offers don't fully represent fuel costs because of how that would administratively burden resource owners, he said. The circuit breaker could create a disparity between the pricing run and the dispatch run, creating a challenging reliability situation for PJM if it's not sending the proposal signals for generators on how to operate.

The board called for the continuation of the process of creating a circuit breaker in a *March 10 letter* and asked that a proposal be brought to it by July.

PJM, Monitor Review IROL-CIP Proposals

PJM's Darrell Frogg presented a first read of the RTO's proposal to create a cost-recovery mechanism for investments required under NERC's interconnection reliability operating limits (IROLs) under its Critical Infrastructure Protection (CIP) standards. The proposal was endorsed by the Operating Committee on March 9, receiving 89% support, while the Monitor's proposal receive 11%. (See *PJM OC Briefs: March 9, 2023*.)

The proposal would function similarly to PJM's existing black start cost-recovery mechanism, with generators submitting costs to the RTO and Monitor to review and reviews collected through charges to market participants. Supporters speaking during the OC argued that having a facility declared critical by NERC and required to make reliability upgrades is outside of their control, can carry significant costs and is unpredictable.

The MRC is slated to consider voting on the proposal during its June meeting. Assuming stakeholder endorsement, PJM plans to file a Federal Power Act (FPA) Section 205 filing around August.

Members Committee

PJM Launches Webpage for Tracking Resource Adequacy Concerns

PJM Vice President of State and Member Services Asim Haque told the Members Committee the RTO is planning to launch stakeholder processes on many of the issues discussed during a panel on reliability at its annual meeting.

A *page* on the RTO's website has been created to track ongoing studies and detail how it plans to address future reliability and resource adequacy. (See "Panel Discusses Future Reliability Landscape," *PJM CEO, Panelists Address Reliability During Annual Meeting*.)

Haque discussed the three timelines the overarching concerns fall into: the immediate need to support resource performance, the near-term need to ensure resource adequacy, and the upcoming concern for maintaining and attracting essential reliability services.

Public Power Decries Override of MC Endorsement on CP

Representing the PJM Public Power Coalition, Customized Energy Solutions' Carl Johnson said it's concerning that the PJM board has opted to disregard stakeholders' endorsement of a proposal to revise the Capacity Performance (CP) construct to reduce the penalties generators face for not meeting their obligations during emergencies.

The MC voted May 4 to endorse a proposal redefining the penalty rate and annual stop-loss limit as being derived from the Base Residual Auction clearing prices, rather than the net cost of new entry, as well as tightening the circumstances under which PJM can declare a performance assessment interval (PAI). Later that month, the board announced that it would only be including changes to the PAI trigger in a FERC filing. (See *PJM Board Rejects Lowering Capacity Performance Penalties*.)

Johnson expressed his displeasure that PJM chose pieces of a larger package supported by stakeholders to present to FERC, particularly as work continues in the Critical Issues Fast Path process to create proposals overhauling the capacity market.

"It puts groups like mine in a really difficult position when we're looking to build consensus on a proposal in the future," he said.

American Municipal Power's Lynn Horning said there's open space for stakeholders to consider rules and more specificity around when packages can be partially advanced to FERC.

Avangrid Renewables' Kevin Kilgallen said the proposal would have injected uncertainty into delivery years for which capacity auctions had already been run. The language would have been effective through the 2024/25 delivery year.

"To change the product definition without there being an urgent need to do so ... between the auction and the delivery year, we thought that's very bad policy, and it adds another level of uncertainty," he said.

PJM CEO Manu Asthana said staff and the board don't take the decision to override stakeholders lightly, but the RTO holds the authority to make changes under FPA Section 205 and has an obligation to make filings it believes will uphold reliability.

"I don't want to keep doing this, but I think it's a two-way street: We recognize where the stakeholders have ... rights, and we give deference as much as we can," he said, noting that stakeholders hold the rights to make changes related to the Operating Agreement. ■

— Devin Leith-Yessian

SPP News

NextEra Gets Final OK for Kansas-Missouri Tx Line

Kansas Regulators Grant NEET Southwest Siting Authority

By Tom Kleckner

Wolf Creek Nuclear Generating Station lies at one end of the Wolf Creek-Blackberry project. | *Office of Nuclear Energy*

The Kansas Corporation Commission (KCC) last month granted a siting permit for NextEra Energy Transmission (NEET) Southwest's preferred route for the *Wolf Creek-Blackberry 94-mile, 345-kV project*, clearing the way for construction to begin.

The KCC said in a May 24 order that NEET Southwest had "met the requirements" for the siting permit, subject to an alternative reroute, micro siting — i.e., minor modifications to the route and infrastructure placement — and other small modifications agreed upon with a landowner (*23-NETE-585-STG*).

"The commission finds that the method that NEET Southwest used to select its route and the route proposed by NEET Southwest are reasonable and that the siting permit requested by NEET Southwest complies with all statutory requirements and should be granted," the KCC wrote. It said the project "is needed and will have a beneficial effect on customers by lowering overall energy costs, removing inefficiency, relieving transmission congestion, and improving the reliability of the transmission system."

The agency last August issued NEET Southwest a limited certificate of convenience and necessity as a transmission-owning utility for the 94-mile, single-circuit project, which will run from the Wolf Creek Generating Station in Kansas southeast into Missouri. In December, the Missouri Public Service Commission granted Southwest a CCN for the project's nine-mile portion in Missouri. (See "Missouri PSC Grants CCN for NextEra Project," *MISO, SPP Fall Short in 5th Try for Interregional Projects*.)

The project has received pushback from landowners and other critics who say the power will be shipped out of state. Florida-based NextEra is already in county district court litigation over its utility status in Kansas. The company expects the project to be in service by the end of 2024, barring any legal setbacks.

SPP granted the competitive project in 2021 to NEET Southwest over six other bids. The NextEra Energy subsidiary estimated the project will cost $85.2 million. (See "Expert Panel Awards Competitive Project to NextEra Energy Transmission," *SPP Board of Directors/Members Committee Briefs: Oct. 26, 2021*.)

Commissioner Andrew French, who sits on SPP's Regional State Committee comprised of state regulators, joined KCC Chair Susan Duffy in the 2-1 decision. The commission noted a need for SPP to allow state involvement earlier in projects' design process and said it intended to investigate the principles and priorities for future siting dockets. ■

FERC Partially Approves PSCo's Queue Changes

Rule Revisions Aimed at Limiting Speculative Projects

By James Downing

FERC on Friday partially approved Public Service Company of Colorado's (PSCo) proposal to amend its generator interconnection process with changes intended to prevent unready projects from clogging the queue (*ER23-629*).

The Xcel Energy subsidiary in 2019 received commission approval to transition its interconnection process to a cluster study approach, but projects not ready to move forward have continued to slow the process for those that are ready. The unready projects end up withdrawing, leading to problems such as unreliable study results, cascading restudies and delays.

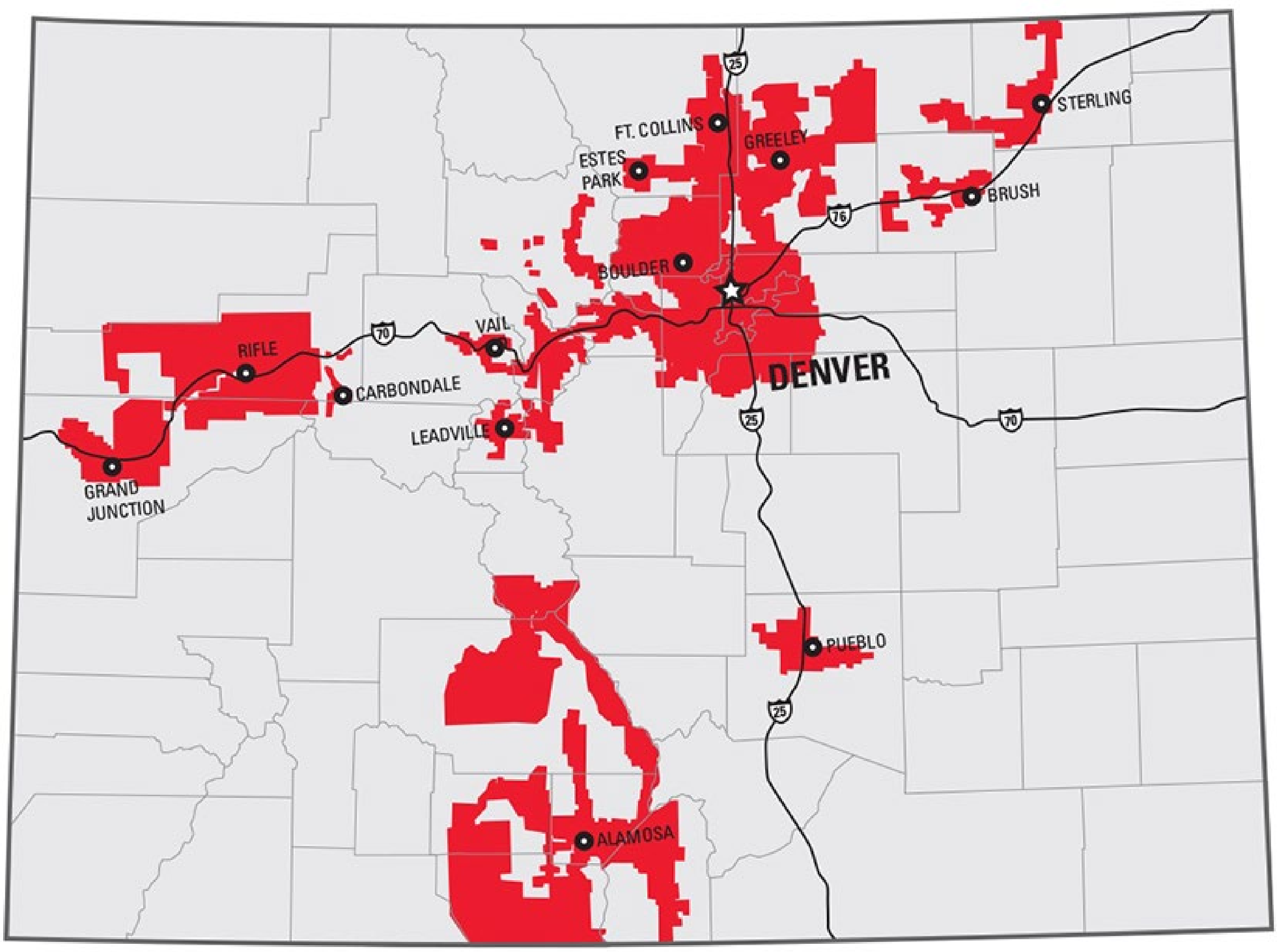
The most recent study cluster has been delayed for two years, PSCo noted, preventing the utility from meeting customers' requested in-service dates and hindering future projects from estimating their interconnection costs.

Under PSCo's existing rules, projects can qualify for the queue if they have offtake agreements, are part of a resource plan or have an in-service date. Developers can also enter a project into the queue if they submit additional security in lieu of making a "readiness demonstration."

In its initial filing, PSCo sought to remove the option for projects to submit additional security, contending that developers picking that option have often wanted to use a large generator interconnection agreement to market their projects but wound up subverting the goal of a speedier processing of interconnection requests, even causing more advanced projects to withdraw from the queue process altogether.

The initial proposal would have replaced the security option with a "generation deployment plan" that would require a developer to have a plan to secure permits, build the facility and finance it. The generation deployment option would also include a $7.5 million deposit, along with withdrawal penalties that vary by project size and rise the later in the queue a project pulls out.

The Solar Energy Industrvies Association, Avangrid and HQC Solar argued the changes were too stringent and would prevent inde-



The Public Service Company of Colorado footprint | © *RTO Insider LLC* pendent power producers from entering the utility's queue. But they did win support from NextEra Energy, which said that while the outcome would be more restrictive than FERC's *pro forma* rules, the changes make sense in Colorado, where generators generally transact with load-serving entities that can trigger clusters of resources in the queue.

PSCo came back with a later filing that added an option for developers using the generation deployment option to pay a $7.5 million security payment and face the heightened withdrawal penalties, without requiring them to meet the other requirements, effectively restoring the security option — which SEIA said was better than the first proposal.

The proposal led to a deficiency notice from FERC, with staff asking how PSCo would evaluate what constitutes a reasonable permitting plan under the generation deployment plan. The utility said it would accept permitting plans that demonstrate an understanding of the land use and environmental permitting process in Colorado.

Staff also asked how the utility arrived at the $7.5 million security amount and associated withdrawal penalties. PSCo said the old withdrawal penalties were capped at $2.5 million, which was not enough, and that $7.5 million is still lower than average interconnection costs.

Security Option Remains

FERC rejected PSCo's initial proposal, but it accepted the alternative in which projects can put up $7.5 million in lieu of being ready to deploy.

"We find that PSCo's proposal to require interconnection customers to either meet the requirements under the proposed generation deployment option or one of PSCo's three existing, unchanged, commercial readiness demonstration options alone is likely too stringent for independent power producers to meet," FERC said. "Based on the record in this proceeding, many independent power producers currently use the security in lieu of a commercial readiness demonstration option in PSCo because it is difficult for them to meet the requirements for the other existing commercial readiness demonstration options."

FERC also agreed with protesters that the milestones in the generation deployment option might be misaligned with typical development cycles and business practices for IPPs.

But allowing projects to post $7.5 million and raising withdrawal penalties will help speed up the queue because PSCo has shown that speculative projects are slowing the process down, FERC said. The higher security requirement will cut the number of speculative projects and thus the associated withdrawals and restudies.

In the two clusters run in 2020, projects representing 66% of the requested interconnection capacity withdrew from the queue, as did 30% the next year, which shows that the current security and withdrawal penalties are not enough to deter unviable projects from getting in line.

Other Penalties

PSCo had also asked to increase to $5 million the security and penalty for projects that sign an interconnection agreement but do not enter service (except for those posting the higher $7.5 million security). It had penalized such projects under a formula of nine times study costs, which topped out below $1 million.

FERC approved the $5 million figure, saying it will increase the likelihood that projects with an interconnection actually get built. The amount is justified because projects that pull out are especially problematic because they cause more restudies than earlier withdrawals, the commission found.

None of the new fines or security requirements will go into effect until 120 days after the rules become effective, which FERC said gives projects that entered the queue under the old rules enough time to pull out in light of the new risks. PSCo initially filed for a 30-day transition, but then offered the 120 days in a subsequent filing to avoid favoring its own generation when it holds upcoming resource solicitation that projects presently in the queue can participate in, FERC said.

Commissioner Allison Clements concurred with the order, saying further changes might be needed to make PSCo's interconnection process fairer when it comes to how penalties are distributed. Withdrawal penalties are currently used to fund generation interconnection studies, but the tariff does not address how such funds should be distributed when they exceed relevant study costs — a risk that is now higher, she said.

"I encourage PSCo to assess whether further changes to its [large generator interconnection procedures] may be necessary in light of the commission's approval of increased withdrawal penalties," Clements said. "If PSCo's proposal renders its existing mechanism for distribution of withdrawal penalties unjust and unreasonable and further changes are not forthcoming, then action pursuant to Section 206 of the Federal Power Act may be appropriate." ■

Company Briefs

NRG Sells Stake in Texas Nuclear Plant; Stock Falls

NRG Energy is selling its stake in the 2,645-MW South Texas Project nuclear power plant to Constellation Energy for $1.75 billion, the companies said last week.

Pending approval from the Nuclear Regulatory Commission, Department of Justice and the Public Utility Commission, Constellation plans to take over NRG's 44% stake by the end of the year.

Following the announcement, NRG's shares dropped by 4%.

More: *Houston Chronicle*; *S&P Global*

Pleasants Power Retirement Delayed Again

The Pleasants Power Plant was set for retirement last week after more than four decades of service, but potential buyers have put those plans on hold.

According to a letter from Energy Harbor to PJM, the company said it intends to keep the Pleasants Power Plant operational through July while negotiations continue between Energy Transition and Environmental Management (ETEM) and other companies regarding its future. Energy Harbor is seeking to change the status of the two coal-fired units from "retired" to "mothballed" and estimates that the status would continue through July 31.

The West Virginia plant is being considered by two different potential buyers. Two FirstEnergy Corp. subsidiaries, Monongahela Power and Potomac Edison, are in talks with ETEM to lease the plant for a 12-month period while it considers closing another power plant and buying Pleasants Power.

More: *The Weirton Daily Times*

Toyota to Invest $2.1B More in NC Battery Plant

Toyota last week said it will invest another $2.1 billion in an electric and hybrid vehicle battery factory that is under construction near Greensboro, N.C.

The investment brings the total investment in the plant to $5.9 billion to meet the company's goal of selling 1.8 million electric or hybrid vehicles in the U.S. by 2030.

The plant, which will begin production in 2025, will supply batteries to the company's complex in Georgetown, Ky., which will build Toyota's first U.S.-made EV.

More: *The Associated Press*

Federal Briefs

Appeals Court Halts EPA Effort to Impose Air Pollution Plan in Missouri

The 8th U.S. Circuit Court of Appeals last week put on hold an EPA regulation aimed at reducing air pollution in Missouri.

Attorney General Andrew Bailey announced that the court granted his request for a stay, preventing the EPA from imposing the regulation until the appeals process plays out. It was not immediately clear whether the EPA would appeal.

At issue is a "good neighbor" provision of the Clean Air Act that requires states to submit a plan detailing how they will address air pollution that can drift to neighboring states. The EPA deemed Missouri's proposal inadequate and in March finalized its plan for the Ozone National Ambient Air Quality Standard.

More: *The Associated Press*

Judge Says Oregon Youths' Climate Lawsuit Against US Can Proceed to Trial

U.S. District Court Judge Ann Aiken last week ruled that a lawsuit brought by young Oregon-based climate activists can proceed to trial years after they first filed the suit to hold the nation accountable for its role in climate change.

Aiken ruled that the plaintiffs can amend their case, known as Juliana v. United States, and go to trial. The 21 plaintiffs, who were between the ages of 8 and 18 when the lawsuit was filed in 2015, will move forward on the question of whether the federal government's fossil fuel-based energy system, and resulting climate destabilization, is unconstitutional.

A previous trial was halted by U.S. Supreme Court Chief Justice John Roberts days before it was to begin in 2018.

More: *The Associated Press*

BLM Seeks Comment on Nevada Solar Project

The Bureau of Land Management is seeking public comments on the Bonanza Solar Project in Clark and Nye counties, Nevada.

If approved, the project would generate up to 300 MW of solar energy and include 300 MW of battery storage on half of the 5,133-acre application area on public lands approximately 30 miles northwest of Las Vegas.

Construction is expected to take 12 months.

More: *Bureau of Land Management*

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NY Green Bank Surpasses $2B in Financing

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State Briefs

CALIFORNIA

PG&E Reaches $50M Settlement with Shasta County in 2020 Zogg Fire

Pacific Gas and Electric will pay $50 million in a legal settlement with Shasta County for its role in the 2020 Zogg fire.

As part of the settlement agreement, which awaits final approval by a judge, criminal charges against PG&E that were filed by the Shasta County district attorney in 2021 will be dropped. The settlement includes $45 million for improving fire safety and emergency preparedness, as well as paying for permanent memorials to the people killed in the fire.

The fire tore through several rural communities, killing four people and burning more than 56,000 acres.

More: *Los Angeles Times*

State Farm to Stop Offering Homeowners Insurance

State Farm, which insures more homeowners in California than any other company, last week said it will stop accepting applications for most types of new insurance policies due to a "rapidly growing catastrophe exposure."

The company said that while it recognized the work of state officials to reduce losses from wildfires, it had to stop writing new policies "to improve the company's financial strength."

More: *The New York Times*

ILLINOIS

ComEd Proposes $119M Expansion of Energy Efficiency Investments

ComEd last week filed a request with the Commerce Commission for a $119 million increase to ICC-approved rates from January, all for further efficiency investment.

If approved, further changes would add approximately 56 cents to the monthly bills of the average residential customer beginning in 2024. However, further investments will only be approved if the ICC finds new costs to be prudent and reasonable for customers.

The ICC's review should take about eight months.

More: *Daily Energy Insider*

MARYLAND

Barve Sworn in as New PSC Commissioner

Kumar Barve was sworn in as a member of the Public Service Commission last week after being appointed by Gov. Wes Moore.

Prior to his appointment, Barve had served in the House of Delegates since 1991.

Barve will succeed Patrice Bubar, who had served since May 18, 2022.

More: *Maryland PSC*

MINNESOTA

Xcel Shuts Down Prairie Island Nuclear Generator After 'Unusual Event'

One of Xcel Energy's two Prairie Island nuclear generators remained shut down after the company reported an "unusual event" to the Nuclear Regulatory Commission on June 1.

Multiple fire alarms — which were not verified as false alarms within the required 15 minutes — went off in a reactor containment building, triggering the unusual event declaration. However, there was no fire and no threat to the public or plant workers, Xcel said in a notification to the NRC. The alarms went off at Unit 2 after an external transformer malfunctioned.

The company said it planned to power up Unit 2 after finishing work on the transformer and completing standard procedures.

More: *Star Tribune*

Xcel to Reassess Investments After PUC's Rate Hike Decision

Xcel Energy last week said it will reconsider significant investments in Minnesota after the Public Utility Commission approved a three-year rate increase that was much less than what the utility wanted.

The PUC approved a $306 million (9%) increase, which also was less than the Department of Commerce and an administrative law judge recommended. Xcel was most recently asking for $440 million over three years.

Xcel said it will ask the PUC to reconsider its rate decision, but in the wake of the PUC's decision, it will re-evaluate its planned investments.

More: *Star Tribune*

Minneapolis Bans New Heavy-polluting Industries, Limits Existing Facilities

The Minneapolis City Council last week voted unanimously on a ban that will, in part, prohibit types of new high-polluting industrial facilities from opening in the city and bar the expansion of existing ones.

The ban, which was passed as part of a zoning code revision, will enforce a citywide prohibition on new scrap metal industries, chemical manufacturers, commercial laundries, combustion powered energy facilities, and foundries. Existing facilities such as the Hennepin Energy Recovery Center and Smith Foundry will be grandfathered in but will be unable to expand operations that contribute to pollution.

The ordinance is part of the city zoning code approved in the 2040 Comprehensive Plan, originally passed in 2018.

More: *Sahan Journal*

NORTH CAROLINA

TW Solar Planning Solar Farm in Davidson County

Spanish renewable company TW Solar is looking to build a $9 million solar project in Davidson County.

The 10.75-MW Thomasville Solar facility, which would sit on 69 acres, would be the largest in the county.

The project is awaiting approval from the Utilities Commission.

More: *Winston-Salem Journal*

NORTH DAKOTA

Canadian Nuclear Project Could Locate Near State Border

SaskPower, a Canadian utility company, is in the process of siting a small nuclear reactor that could be just on the other side of the North Dakota border.

SaskPower is narrowing down potential sites for a GE-Hitachi BWRX-300 small modular reactor, with one possible location in the Estevan region and the other near Elbow. Site selection should be finalized by 2025, with licensing finished by 2029.

More: *Inforum*

Industrial Commission Approves Blue Flint Carbon Storage Project

The Industrial Commission last week approved a carbon storage project that will capture carbon dioxide emissions from Midwest AgEnergy Group's Blue Flint Ethanol plant and transfer them to the underground Broom Creek Formation.

The pipeline from the plant to the storage site will be 3 miles long, and storage will cover about 11 square miles. It will be the second active CO_2 injection well in North Dakota.

More: *The Bismarck Tribune*

OKLAHOMA

OG&E Files Proposal to Increase Power Supply

Oklahoma Gas and Electric (OG&E) last week asked the Corporation Commission to approve its plans to replace two aging generation units at the Horseshoe Lake Power Plant with more efficient units.

The Horseshoe units being replaced are the oldest in OG&E's fleet at 60 years old. OG&E will replace the gas-fired steam units with new gas-fired combustion turbines that will provide about 450 MW.

The project is expected to cost $331 million and will result in an increase of $2.20 per month for the average residential customer — but not until the units begin providing power in late 2026.

More: *OGE Energy*

OREGON

Pacific Power Submits Plan to Achieve Net-zero Emissions by 2040

Pacific Power last week filed plans with the Public Utility Commission to eliminate greenhouse gas emissions for all electricity sold to state consumers by 2040.

Pacific Power also filed its updated integrated resource plan, which advances its trajectory toward net-zero emissions, calling for nearly four times the company's current wind and solar resources. The plan also continues investments in emissions-free technologies, including advanced nuclear and non-emitting peaking resources.

More: *KTVZ*

TEXAS

Boiler Explosion at Luminant Plant Kills Contractor

A contractor was killed when a boiler exploded at a Luminant power plant on May 31, according to a company spokesperson.

The blast occurred around 8 a.m. at the Oak Grove Power Plant, which has remained in operation.

The cause of the explosion is under investigation.

More: *The Associated Press*

VIRGINIA

Appalachian Power to Face New Regulatory System

Beginning in July, the State Corporation Commission will review Appalachian Power's rates and earnings every two years following legislation that significantly changes how the utility is regulated.

Many of the changes in the new law, which will give the commission greater leeway in setting rates, are mirrored in other legislation that changed the regulatory framework for Dominion Energy.

Previously, state law had a system for when rates could and could not be increased. If Appalachian Power or Dominion earned within 0.7% of their allowed profit margin, rates stayed the same. If their earnings were below the lower end of the earnings collar, rates increased. If they were above the upper end of the collar, part of the excess earnings had to be refunded to customers. If the company is found to have over earned, all excess earnings must now be returned to customers. Previously, only 70% had to be refunded.

More: *Virginia Mercury*

Dominion Shuts Down Chesterfield Coal Units

Dominion Energy last week deactivated its two remaining coal units at Chesterfield Power Station.

The units, which have been operational for more than 50 years, are the third and fourth units to be taken offline at Chesterfield in the last decade. The previous two were retired in 2018.

A full decommissioning of the units will follow.

More: *Martinsville Bulletin*

WEST VIRGINIA

DOJ Sues Justice's Coal Companies, Son Over Mine Cleanup Penalties

The U.S. Department of Justice last week sued 13 Gov. Jim Justice family-controlled companies and his son, James Justice III, in federal court, saying they haven't paid more than $5 million in penalties assessed by the Office of Surface Mining Reclamation and Enforcement.

The suit claims the companies and Jay Justice failed to pay uncontested penalties after being cited for more than 130 violations from 2018 to 2022. The Justice Department estimated the penalties and reclamation fees, plus interest and administrative expenses, total roughly $7.6 million.

The lawsuit does not name Gov. Justice.

More: *Charleston Gazette-Mail*

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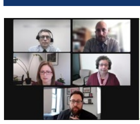

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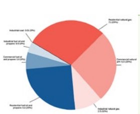

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