ISSN 2377-8016 : Volume 2024/Issue 44 ▪ November 5, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Susquehanna nuclear power station (*Page 26*) | *Talen Energy*

RTO Insider

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In this week's issue

FERC/Federal News

FERC Dives into Data Center Co-location Debate at Technical Conference

By James Downing

A common refrain at FERC's technical conference on the co-location of data centers held Nov. 1 was that the issue is just part of the broader problem of how to meet growing demand as older power plants retire and new ones are often delayed from coming online (*AD24-11*).

While many speakers made that argument, co-location itself could either help or hinder the industry's efforts to ensure resource adequacy.

Chair Willie Phillips opened the conference by laying out how ensuring data centers are built in the U.S. is a major policy priority, alongside reshoring manufacturing.

"In my opinion, data centers, artificial intelligence [and], indeed, the full panoply of information-related technologies that are transforming the world are national resources with generational significance and vast national security and national economic consequences," Phillips said. "They belong in the United States, and I believe that the federal government, including this agency, should be doing the very best it can to nurture and foster their development."

Large data centers are willing and able to pay for the new capacity needed to integrate them reliably, he added. The sector could help anchor the infrastructure that the grid needs to maintain reliability, he argued.

But they are coming online on a grid with a shrinking reserve margin, with Commissioner Mark Christie noting that PJM has warned it could be short on supply by 2030.

"One of the big issues here, of course, is resource adequacy," Christie said. "And one of the questions to be asked is, if you're taking dispatchable resources — and when we talk nukes, we clearly are talking dispatchable resources — if you're taking them out of the supply stack, what does that do to resource adequacy? That's a huge issue that needs to be explored."

Another issue is fairness to consumers, such as whether they will pay the non-bypassable charges all retail customers face if they are behind the meter at a nuclear plant, Christie said.

Pulling resources off the generation stack to serve data center load can have major cost impacts on the rest of the market, Maryland Sen. Katie Fry Hester (D) said. She quoted an *analysis* from PJM's Independent Market Monitor estimating the cost of redirecting 1,000 MW from the Calvert Cliffs plant to serve a data center.

"They found that removing 1,000 MW of power from Calvert Cliffs, which was their approximation for a co-located data center, would increase the cost to Maryland in the 2025/26 [capacity auction] by $332 million," Hester said. "I mean, that is a shocking number. And when the companies sit up here and say they're paying their fair share, they may be paying for their immediate energies, but they're not taking into account what it's going to cost us to build the transmission for everybody else who's no longer served by this power."

Google: Speed to Market the Main Reason for Co-location

Google is not trying to avoid the costs of plugging into the grid with its exploration of co-location deals, said Brian George, the company's U.S. federal lead on global energy market development.

"Co-location in the context that we're talking about right now is really just a response to a market inadequacy, right?" George said. "We're trying to figure out how we can get new loads onto the system in a way that meets our growth objectives. And so, I think that is important because it's driven by the need to access the market."

Google is not trying to avoid transmission and distribution costs by locating data centers behind the meter at power plants, he added.

"It is really kind of our preference to see the grid planned in a way that meets our needs, in collaboration with our utility partners, with our RTO partners; that it's baked into forecasts. We're sending resource adequacy signals," George said. "That is where we want to go."

Constellation Energy, the owner of Calvert Cliffs and the largest fleet of nuclear plants in the U.S., sees the growth in data centers and co-location as a way to ensure those assets stay profitable and producing power for decades, said Mason Emnett, senior vice president for public policy. It was only recently that nuclear plants were starting to retire because of low wholesale power prices.

"That led to a number of state programs and then ultimately a federal program that will be rolling off right as 40% of our fleet is turning over their 20-year licenses," Emnett said. "So, from our perspective, the opportunity to serve this critically important load creates a long-term commercial pathway to relicensing."

The kind of long-term deals that data center clients are interested in could help provide the financial backing to eventually add new nuclear plants to the grid, he added.

Constellation wants to serve more customers through traditional power purchase agreements as well, and Emnett said co-located load should pay its fair share.

"What does 'fair' mean for a load that has no ability to pull power from the grid?" he said. "It's not gross load. ... We can have a conversation about that, but when you have litigation positions that are so far apart, then it makes it difficult, and ultimately, it's the job of the regulator to call balls and strikes."

That litigation involves the firm that Constellation was spun off from in 2022, Exelon, with the two and other generators and utilities lining up on opposite sides of pending FERC cases on co-location. (See *Exelon, Constellation at Loggerheads over Data Center Co-location*.)

Co-location's Impacts on Resource Adequacy

Exelon supports co-location, which is not a new process, said Vice President of Transmission Strategies David Weaver.

But the issue is that the recent deals Constellation has pursued in Exelon utility territories have not followed the rules in their tariffs.

Proposed data centers can range in demand up to 1 GW, while each of Exelon's utilities on average serve about 6.4 GW of load.

Why This Matters

FERC has started the process of looking into what issues it needs to resolve around co-located data centers, such as ensuring the facilities pay for any benefits they still derive from the grid. But the issue that is behind it all is declining resource adequacy, and what impacts removing cheap, nuclear power from serving other customers can have.

FERC/Federal News

"There's a number of potential reliability impacts and reliability studies that have to be performed, right?" Weaver asked. "You've got not only the thermal flow issue that the protection is in place for, but you've got stability issues ... short-circuit issues, and all those things that have to be considered."

Ultimately, even resources behind the meter at a nuclear plant rely on the grid, and Weaver argued they should have to pay their fair share of its costs.

PJM Monitor Joe Bowring also said co-location does not mean the plants are off the grid and agreed that the issue is a sideshow to the main issue facing the RTO now.

"The issue is reliability," Bowring said. "At the moment, PJM is right on the edge and talking about … adding 10 [thousand MW] or 20,000 MW of load on a system that is already very tight."

PJM is working on rules to help get more supply onto the system, including a process to get power plants that can increase reliability to the front of the queue. (See *Stakeholders Divided on PJM Proposal to Expedite High-capacity Generation*.)

"It makes sense to think really hard and try to be effective about getting new resources online," Bowring said. "But from a static perspective, it does not make sense to add 10,000 MW of load behind some of the most critical generators on the system, the nuclear power plants."

Adding 20 GW of data centers would represent most of PJM's nuclear capacity, which are important facilities around which the entire grid has been planned, he added.

Co-located load brings up questions such as whether the customer is using the transmission system, how much the facility benefits from ancillary services and whether a retail sale is involved, said Copper Monarch Principal Vincent Duane, former general counsel for PJM. But that misses the bigger question of what impacts such deals are having.

"Whether we have a data center connecting in front of the meter, or whether we're connecting that data center behind the meter, we are going to see more or less similar impacts and consequences on the system, whether we're talking about reliability impacts or the supply-and-demand impacts, or the system needs, including the need for new transmission upgrades," Duane said.

Data center load growth in Virginia and power plant retirements in Maryland led to billions of dollars of need for new transmission in PJM's most recent regional plan. The impact of taking capacity from an existing plant to serve a data center is functionally equivalent to a retirement, Duane said.

FERC hosts a panel of representatives from states during the data center co-location technical conference on Nov. 1. | *FERC*

Independent Consultant Mike Kormos, who wrote a paper for Constellation filed in one of the dockets noticed in the technical conference, said co-location deals already take many of those issues into account.

"The risk is on the generator in the data center," said Kormos, former COO of PJM and senior vice president for Exelon. "They are obligated to pay for network service upgrades."

PJM has been clear that it will turn down co-location arrangements if they do not deal with reliability issues on the power grid, he added. For data centers that plug into a utility's distribution system, the RTO has no such power.

Co-location's Impact on Grid Operations

Some have questioned whether data center load can truly be isolated from the grid; Talen Energy Executive Vice President Cole Muller said that was certainly possible.

His firm's Susquehanna nuclear plant has a co-located data center owned by Amazon, the expansion of which brought the debate before FERC. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC*.)

Before Muller was at Talen, he worked on nuclear submarines for the U.S. Navy.

"We had protective relays in place to protect the reactor in case extraordinary circumstances happen and really high-consequence scenarios," Muller said. "And so, if we are able to rely on relay schemes for a national security asset like a ballistic missile submarine, we should be able to rely on these kind of schemes for protecting the grid from co-located load."

Even if the data centers are only taking power from the nuclear plants, they can still have operational impacts on the grid, said Howard Gugel, NERC vice president of regulatory oversight.

"What happens if you lose the load, that generation is now over-generating on the system?" Gugel said. "What do you do then? Do you back down the generation? Do you trip the generator? How do you restore from that? So there's other scenarios I think that need to be taken into account here."

Large data center loads operate very differently than other kinds of load, Gugel said. He compared them to inverter-based resources, which NERC has been dealing with for years and can have cascading events where many go offline at once, exacerbating grid disturbances. This summer, a single line-to-ground fault on a 230-kV transmission line took out 1,550 MW of nearby data centers.

"It was interrupted normally on the line, at 1/28 of a second the breakers operated; the line was taken out," Gugel said. "But because of that voltage perturbation that occurred, you had a significant amount … of load, over 25 substations and about 60 different providers, that saw the impact from that. All the interruptions occurred behind the meter. It wasn't any action that was taken by any utility or any ISO."

Until the industry gets better modeling and more experience operating the grid with more data center load, it is going to be difficult to understand their impact on reliability, he added.

Figuring out how data centers are going to impact the grid is more difficult because the facilities differ significantly.

"I think one of the things that I'm very concerned about is each one of these data centers is going to be a snowflake," MISO Vice President of System and Resource Planning Aubrey Johnson said. "And so, they're going to have their own design, their own issues, their own concerns, their own configuration that they'd like to meet."

Most have backup generation, even those behind the meter at a nuclear plant, but that comes with questions on how long that can run under state air permits. The design of an interface between a co-located data center and the grid can have a major impact too, such as whether it just blocks power from serving the load or whether it can also let power flow out in a demand response situation, Johnson said.

"So, if we want to think about a set of rules, I think they either need to be very, very specific and start creating a formulaic approach to how you work behind the meter, and/or you have to think about making them broad enough to be simply a set of guidelines we should already be paying attention to," Johnson said. "I think fundamentally we ought to lean in on reliability and have that be the basis upon which we build off." ■

FERC/Federal News

Rosner Hopeful for Consensus on Order 1920 Rehearing

EEI, DOE Talk Supply Chain at WIRES Fall Meeting

By James Downing

FERC Commissioner David Rosner hopes the rehearing order on Order 1920 will win broader support than the 2-1 split vote that produced the original.

Speaking at the WIRES Fall Member Meeting, Rosner said that based on the comments in the docket and discussion with his colleagues, many stakeholders agree on some modest changes to the original that are still in line with its intent to expand the transmission grid.

"I'm really hopeful that we can get five votes on a rehearing order, but I don't know, we'll see what happens," Rosner said. "I mean, all I can really guarantee is one vote, but I'm committed to work through that."

One area Order 1920 did not address much was interregional transmission, Rosner said, adding that he would be happy to implement anything Congress manages to pass. Expanded authority over interregional transmission is part of the Energy Permitting Reform Act that cleared the Senate Energy and Natural Resources Committee this summer and could move forward in a lame duck session after the election. (See *Manchin-Barrasso Permitting Bill Easily Clears Committee*.)

NERC CEO Jim Robb's argument at the recent FERC reliability technical conference that interregional transmission can help the grid deal with emerging issues resonated with Rosner, he said. (See *FERC Grills Grid Stakeholders on Reliability*.)

WIRES Executive Director Larry Gasteiger (left) and FERC Commissioner David Rosner | *WIRES*

"I think interregional is really important," Rosner added. "I also don't have any updates on commission action on that, but I will leave it at, I think it's really important. … We have a good record open already on this, and we have lots to think about."

Supply Chain's Impact on the Grid

While FERC has plenty of work to do on its own to ensure grid reliability, some issues largely fall outside of its purview, which includes supply chain disruptions, such as during the COVID-19 pandemic, noted Hailey Siple, director of national security policy for the Edison Electric Institute.

The first weeks of the pandemic were some of the busiest of Siple's career, she said, as she had to work to help manage the industry's response.

"While we were doing that, that is the first time that I remember really sitting down and thinking about supply chain, the energy supply chain in particular, as a national security threat," Siple said. "And I think the conversation changed very much at that point. So, we had really no immediate impacts those first couple weeks or months, but a few months down the road, we had first one of our chief procurement officers come and say, 'Hey, we're seeing some long lead times.'"

EEI started to hear from more and more of the industry that the pandemic was stretching supply lines thin, so it started working to help address the issue along with the rest of the industry and the Department of Energy.

"There is a fantastic relationship between industry and not just EEI, but all segments of the industry, and the Department of Energy through the Electricity Subsector Coordinating Council," Siple said. Once the worries about the supply chain were known, ESCC set up a team to work on the issues, she recalled.

Now DOE itself has set up its Office of Manufacturing and Energy Supply Chains to help coordinate the issue, said its chief strategy officer, Arthur Haubenstock.

Why This Matters

Commissioner Rosner is hopeful FERC can come together and agree on a rehearing order for Order 1920. The commission is expected to act on rehearing in the coming months.

"A good chunk of what we are programming is in transmission, because it is the lifeblood of our energy system, and will increasingly be so as we work on industrial decarbonization, which is another area that our office is responsible for," he added.

The need to get energy supply chains right will also be important to deal with the strains being placed on the grid, whether it is from climate change or increased demand, Haubenstock said.

Increased demand from data centers, and the utilities looking to plug them into the grid, has been a huge change for Siemens Energy, one of the main suppliers of electric transmission infrastructure, said Anthony Zito, the company's director of sales operations.

Customers are increasingly aware of the strains and trying to book equipment a decade ahead of time for sites that are not even on the drawing board now, Zito said. But with the need for data centers, the equipment will definitely be used.

"We had one data center customer that, four years ago, we were the sole supplier to them globally," Zito said. "We now can't serve more than 20% of what they say their need is for the next couple years."

Demand is so high, some data center developers and utilities have approached Siemens to buy out all its capacity for the next five or 10 years, he added. The firm has declined such offers because of the risk that a single customer's business plans could change.

"What happens if they go bankrupt, or they decide they're not building anymore, and now you've alienated every other customer, every other utility, data center customer, renewable customer?" Zito said. "So, we look at sort of a mitigation strategy to spread the love around." ■

FERC/Federal News

Federal Judge Tosses Out Texas' ROFR Law in Non-ERCOT Regions

By James Downing

A federal judge found Texas' law instituting a state right of first refusal (ROFR) law violates the Commerce Clause and prohibited its enforcement in non-ERCOT regions, in an order issued Oct. 28.

Judge Robert Pitman of the U.S. District Court for the Western District of Texas in Austin handed down the ruling on remand from the 5th U.S. Circuit Court of Appeals in the case of *NextEra Energy Capital Holdings v. Kathleen Jackson* in her official capacity as a commissioner of the Public Utility Commission of Texas. (See *5th Circuit Finds in Favor of NextEra's ROFR Appeal*.)

The 5th Circuit decision also was appealed to the Supreme Court, which declined to take up the case in December 2023. (See *SCOTUS Won't Take up Texas Appeal of ROFR Law*.)

The Texas Legislature passed SB 1938 after FERC Order 1000 removed federal ROFRs but required ISO/RTOs such as MISO and SPP, which serve the parts of Texas in the Eastern Interconnection, to respect state ROFR laws.

The law caused NextEra to lose a transmission project in East Texas that it had won in MISO's competitive planning process and another project it had tried to buy from an incumbent in SPP's territory.

The *Commerce Clause* of the U.S. Constitution gives the federal government the power to regulate interstate commerce. State laws can get around it if they have legitimate policy reasons. But the judge knocked down all the arguments ROFR supporters brought up in the case.

Texas claimed the law codified existing practices. But NextEra was able to build in the state prior to enactment of the ROFR law, as it did in the Competitive Renewable Energy Zone law. Another justification was to clean up statutory language after the CREZ lines were opened to out-of-state firms. The judge found that was not a valid reason to get around the Commerce Clause.

Texas also wanted to avoid federal rate regulation, but the judge shot down that reasoning.

"Balkanizing a state from interstate commerce is the very problem the Commerce Clause is meant to guard against … and so Texas' desire to avoid the interstate market — and the federal regulation that comes with it — is not a legitimate local interest," the court ruling said.

The final reason was an alleged impact to reliability because the competitive bidding process adds time to transmission development. But SPP transmission lines that are needed quickly can get around the competitive process. And MISO does not have a competitive process for lines that are needed solely for reliability.

"The federal bidding process does not undermine reliability by substantially delaying projects because these projects already take years to plan," the court ruling said. "The type of transmission lines defendants are concerned about are proposed through federal regional planning bodies to promote long-term transmission development. Even without a competitive bidding process, the procedure for identifying those types of regionally planned transmission lines is time consuming."

Texas can ensure reliability with the PUC's certificate process, and the regulator continues to have authority when lines are in service to ensure they are operated reliably, the judge said.

"If those processes are insufficient to ensure reliability, then Texas could enact new laws that add reliability mandates," the decision said. "The constitutional solution to Texas' issue of ensuring reliability is to evenhandedly increase reliability standards, not to treat all out-of-state entities as necessarily unreliable."

When it comes to competitive processes, FERC requires transmission planners to consider reliability. MISO found NextEra's proposal for the Hartburg-Sabine project had adequate plans and infrastructure in place to ensure reliable operation. NextEra has a pending case before the D.C. Circuit Court of Appeals to try to get that project back, though MISO and FERC have since said it is no longer needed. ■

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Notable Quote

"Balkanizing a state from interstate commerce is the very problem the Commerce Clause is meant to guard against," U.S. District Court Judge Robert Pitman said in his ruling.

FERC/Federal News

EPRI Launches DCFlex Initiative to Help Integrate Data Centers on the Grid

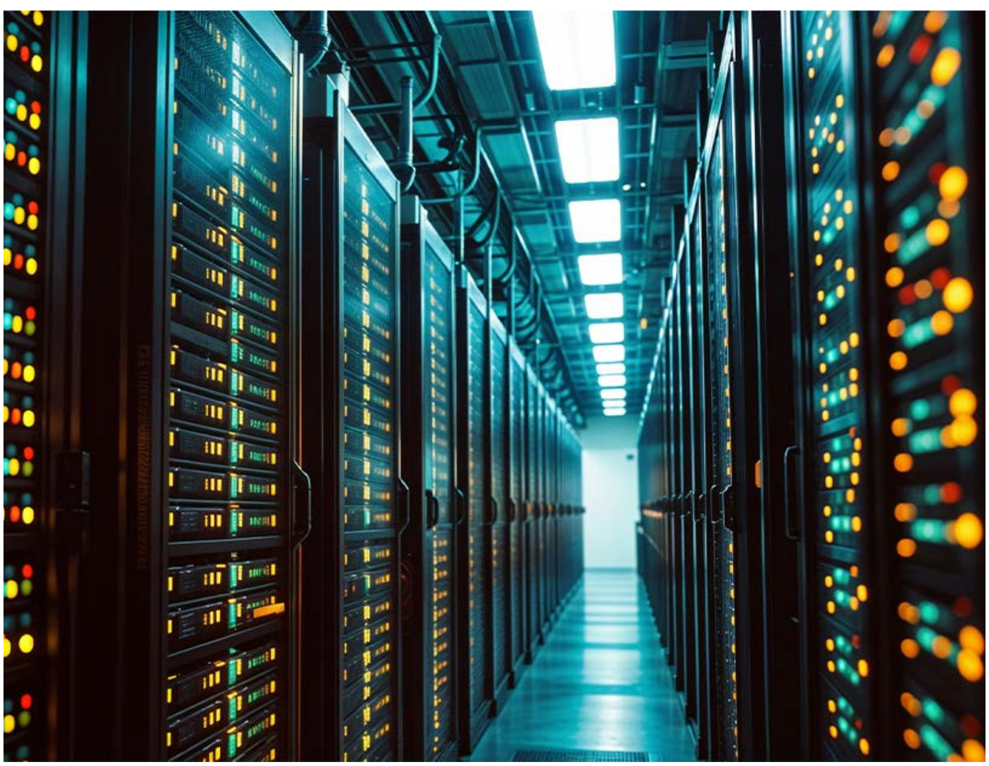
By James Downing

The Electric Power Research Institute has launched its "DCFlex" initiative that will explore how data centers can support the grid, enable better asset use and support the clean energy transition.

The initiative's founding members include Compass Datacenters, Constellation Energy, Duke Energy, ERCOT, Google, Meta, New York Power Authority, NRG Energy, NVIDIA, Pacific Gas and Electric, PJM Interconnection, Portland General Electric, QTS Data Centers, Southern Company and Vistra.

DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit consumers.

The initiative announced Oct. 29 will set up five to 10 flexibility hubs, demonstrating strategies that enable operational and deployment flexibility, streamline grid integration and transition backup power solutions to grid assets. Demonstration deployment will start in the first half of 2025 with testing running through 2027.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Why This Matters

Demand from data centers is at a scale of load growth not seen since just after World War II. The new initiative to maximize their load flexibility can make the interconnection process run more smoothly and help ensure reliability when data centers are operating.

"One of the key areas where people are talking a lot, but not doing a lot, is the area of understanding how flexible data centers can be, and how we actually make that happen," EPRI's Principal Technical Executive Tom Wilson said in an interview. "And so that was the motivation."

EPRI is a nonprofit that works to address challenges in the energy industry. The DCFlex initiative was born out of *discussions* at the U.S. Secretary of Energy's Advisory Board about how it could help power data centers. EPRI spoke with 50 experts from the power industry and the data center industry, Wilson said.

Data centers can respond to signals in the grid in two ways — some of their computational tasks can be shifted around in time and to other data centers, and backup power generation at the facilities can be used instead of the grid, Wilson said. Diesel generation dominates their backup power now, but cleaner options more regularly could respond to grid signals without violating state air permits.

"In terms of computational flexibility, I'd say, you know, if you're at an ATM trying to get money out, and you get the answer that you can't get your cash until the electricity prices are lower or there's more electricity available, you won't be happy," Wilson said. "And so, there are a lot of functions of data centers that you do have to have real time. Basically the customer-facing things that data centers do. Other things like indexing the web and activities like that are potentially more flexible in where they occur and when they occur."

The customer-facing aspects of artificial intelligence also need to be ready for use whenever, but AI models require training, and that energy-intensive process can be shifted in time, Wilson said.

Google, for example, has shifted computing demand to where cheap, clean power is available at its different data centers for the past five years, he added.

"At Google, we see this moment as a generational opportunity for the public and private sector to work together to meet energy demand responsibly and unlock significant benefits for people, the economy and the planet," Google's Global Head of Energy Market Development and Innovation Caroline Golin said in a statement. "Through the leadership, expertise and convening power of EPRI, DCFlex will be an important collaboration vehicle to align our common goals, as we work together to build a stronger electrical grid for all."

Data centers have helped transform the demand for power. The U.S. had flat growth for roughly two decades, but with data centers being added in the hundreds of megawatts, reshoring of industry and efforts to electrify other uses of energy, that has changed dramatically in the past year, Wilson said.

It used to be easy to plug a data center into the grid, but the growing demand has slowed the process. In 2022, Dominion put a moratorium on new connections in its territory, which includes the largest concentration of data

FERC/Federal News

centers in the world, called Data Center Alley in Loudon County, Va., Wilson said.

A 500-MW data center is equivalent to tens of thousands of homes being added to the grid much more quickly than more granular demand growth from an expanding population or a growing economy. Flexibility can help the grid absorb major new loads more quickly.

"In many cases, if you have transmission issues, it may just be that I can provide the power you want for 350 days a year," Wilson said. "For 15, I can't guarantee it for every hour in those days because of congestion, peak temperatures or higher, low — different issues. And if you have that response, is there a way to get around providing that powerful 15 days for the data centers in order to connect it now?"

When it comes to data flexibility, being able to dial back the demand from a 500-MW data center offers a significant source of demand response for the grid, he added.

"Or if it's able to turn on backup generation and take its load entirely off the grid, that's a huge amount of capacity that can come online," Wilson said. "Historically, we've seen this with aluminum smelters and other large industry right where they've traditionally gotten a phone call that said, 'Can you guys turn off these hours, these days?'"

Another key is better planning around when and where data centers want to connect to the grid, said Wilson. It takes time to stand up a new data center.

"Better coordinating those ramp up schedules is really important for an understanding where both parties really are in terms of their needs and ability to respond," Wilson said. "Because, you know, if you're talking a gigawatt data center or 500-MW data center that's a large amount of load, and it can be in over eight years or three years or two years. It makes a big difference."

Constellation, which has worked with Microsoft to reopen a Three Mile Island nuclear plant to serve a Microsoft data center and has discussed co-locating data centers at its other nuclear plants, welcomed EPRI's initiative.

"Data centers are integral to our daily lives, economy and national security," Constellation CEO Joe Dominguez said in a statement. "Our energy system is built to handle the extreme demands of our hottest summer days and coldest winter nights but is often underutilized. The real challenge isn't a lack of energy for data centers but managing the peak demand hours. The ability of data centers to flex during these critical periods is crucial." ■

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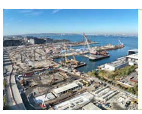

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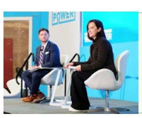

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CAISO/West News

BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits

E3 Analysis Provides 'More Context and Nuance' for Final Market Decision, Agency Says

By Robert Mullin

New findings from a much-anticipated study have "not shifted" Bonneville Power Administration staff's recommendation that the agency choose SPP's Markets+ over CAISO's Extended Day-Ahead Market (EDAM), BPA said Oct. 31 — despite results showing greater financial benefits from EDAM.

"Right now, the economic analysis from production cost model studies leans toward EDAM and the additional analysis from E3 [Energy and Environmental Economics] provides more context and nuance that will be factored into our final decision," Rachel Dibble, BPA vice president of bulk marketing, said in a press release announcing publication of the *study*, which is posted on the agency's website.

Release of the E3 analysis comes three weeks after The Brattle Group published a study — not commissioned by BPA — estimating that, by 2032, the agency would earn $65 million in benefits from participating in EDAM versus an $83 million net loss in Markets+. (See *Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW*.)

"We continue to believe Markets+ is a superior market design for Bonneville and our customers, which includes a truly independent governance model," Dibble said, reemphasizing a point agency staff made in issuing its "leaning" in favor of the SPP market in April. (See *BPA Staff Recommends Markets+ over EDAM*.)

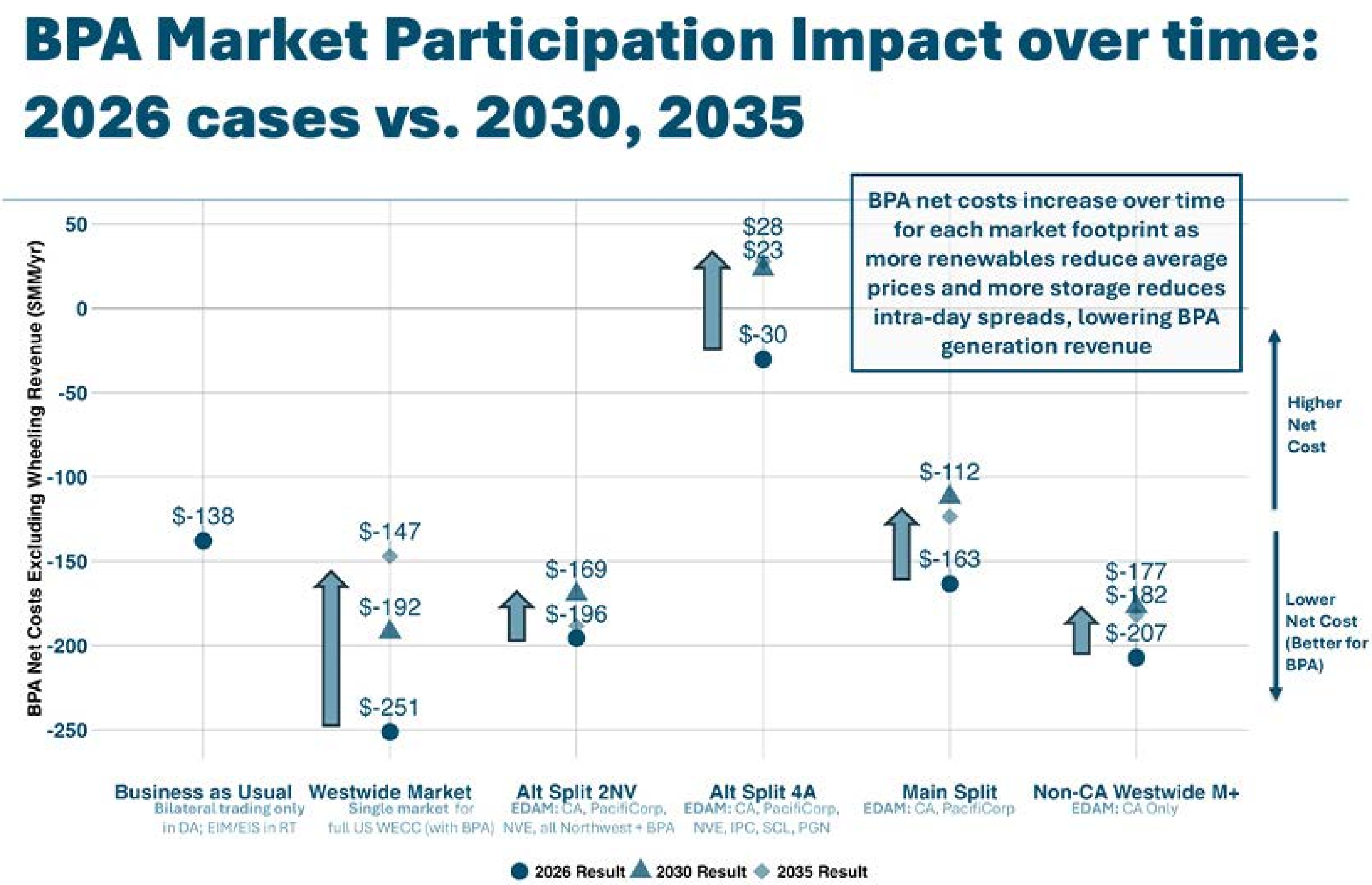
Dibble said BPA "understands the gravity" of its day-ahead market decision "and remains committed to an open and transparent evaluation of market options."

BPA plans to discuss the results during its Nov. 4 day-ahead market participation workshop, the first such meeting since announcing it would delay its market decision until 2025 and since the resignation of the executive leading its day-ahead efforts, former Director of Market Initiatives Russ Mantifel. (See *BPA Markets+ Support Intact Despite Exec's Resignation, Agency Says*.)

The new study consists of "supplemental production cost modeling analysis and sensitivities of cost benefit results regarding BPA's potential participation" in either market, BPA said in its release.

The analysis builds on the 2023 Western Markets Exploratory Group (WMEG) study E3 performed for BPA last year. (See *Study Shows Uneven Benefits for California, Rest of West in Single Market*.)

The 2023 study offered a mixed picture, with BPA expected to incur financial losses compared with the status quo from participating in either market due to an expected sharp reduction in wheeling revenues. BPA questioned



E3's supplemental study on day-ahead market participation for BPA includes net-benefit estimates for the agency in multiple market footprints over three time frames. | *E3*

CAISO/West News

that finding, contending that most of those revenues derive from long-term contracts likely to be maintained for the foreseeable future. By restoring those wheeling revenues into the study's modeling, BPA found it would realize gains from participating in either market and that its net benefits from EDAM would exceed those in Markets+ by nearly $106 million annually.

Supplemental Scenarios

The 2023 WMEG study for BPA examined two scenarios, including an "EDAM Bookend" case in which the entire West participates in the EDAM, and a "Main Split Footprint" scenario, which assumed EDAM membership for only PacifiCorp, Los Angeles Department of Water and Power, Balancing Authority of Northern California, Turlock Irrigation District and Imperial Irrigation District, with the rest of the West joining SPP's Markets+. Both scenarios were measured against a "Business as Usual" (BAU) case in which CAISO's Western Energy Imbalance Market retains its current membership and day-ahead trading in the West outside CAISO continues to occur in the bilateral market.

A *presentation* prepared by E3 for BPA's Nov. 4 workshop shows the new supplemental study retains the BAU and Main Split cases, while the EDAM Bookend case is renamed "Westwide Market" and refers to a scenario in which nearly all of the Western Interconnection, excluding British Columbia and Alberta, participates in a single, unspecified market.

The supplemental also includes three other scenarios:

- "Alt Split 2NV," in which the EDAM includes California, NV Energy, PacifiCorp and the entire Pacific Northwest, including BPA.
- "Alt Split 4A," in which the EDAM includes California, NV Energy, PacifiCorp, Portland General Electric, Seattle City Light and Idaho Power, all of which either have committed to or are likely to join the CAISO market.
- "Non-CA Westwide M+," in which only California entities participated in EDAM while the rest of the West joins Markets+.

The study estimates BPA's benefits under each scenario for 2026, 2030 and 2035.

In its press release, BPA said the analysis shows "a wide range of outcomes, with results pointing to Markets+ providing lower load costs and EDAM providing greater generation revenue potential driven by higher prices."

The agency said the results show "EDAM having greater volatility in benefits than Markets+, although most scenarios still pointed to EDAM having the greatest generation revenue potential. The results also show market benefits declining for both markets in future timeframes, with EDAM depicting a greater decline in benefits, but still maintaining more net benefits than Markets+."

> ### Why This Matters
>
> E3's latest day-ahead market benefits study for BPA is likely to provide fodder for EDAM supporters and turn up the heat on the already contentious debate over which market the agency should join.

Slide 18 in the E3 presentation plots out those findings, showing that under the Westwide Market scenario, BPA would realize $251 million in net benefits in 2026, declining to $192 million in 2030 and to $147 million in 2035.

Under the Alt Split 2NV scenario, BPA would earn net benefits of $196 million in 2026, falling to $169 million in 2030, but returning to close to the 2026 level in 2035.

The Non-CA Westwide M+ scenario shows BPA realizing $207 million in benefits in 2026, $182 million in 2030 and $177 million in 2035, although that scenario is unlikely given utilities' existing and tentative commitments to EDAM.

BPA's worst outcomes occur in the Alt Split 4A scenario, in which it would see $30 million in benefits in 2026, but incur $23 million and $28 million in costs, respectively, by 2030 and 2035.

The study also includes sensitivity cases for each scenario in 2026 to estimate benefits under "dry hydro" and "stress load" conditions.

"Dry hydro regional conditions reduce quantity of generation that BPA has to sell but increases regional prices; BPA net costs are least sensitive to these changes in Alt 4A," E3 notes in its presentation.

E3 said also stress load conditions are applied for only two weeks a year and have only "modest impact" for BPA's net annual costs, although estimated prices "may not reflect full potential scarcity conditions."

Other sensitivity cases cover improved market-to-market (M2M) coordination between EDAM and Markets+ over time and increased transmission availability between the Northwest and Southwest in the future.

"The results provide BPA with another data point in its day-ahead market decision and will be shared at a Nov. 4 workshop," BPA said. "Other factors the agency is evaluating include governance, attribution of greenhouse gas emissions to the federal system, statutes and reliability."

Initial Reactions

Michael Linn, director of market analytics for the Public Power Council (PPC), which has urged BPA to join Markets+, told *RTO Insider* that while the PPC still is reviewing results of the supplemental analysis, its "preliminary view" is that BPA's participation in a day-ahead market will provide benefits to the agency's customer base of publicly owned utilities.

Linn said the various scenarios show "the production cost benefits to BPA can vary wildly depending on a range of assumptions."

"Varying market footprints and hurdle rates appear to show a two-market footprint with BPA in Markets+ can produce benefits at levels similar to BPA participating in EDAM," he said. "These results reinforce PPC's perspective that while production cost studies are important and show directional benefits of day-ahead market participation, when determining the best path for BPA and preference customers, it is equally important to place significant emphasis on real-world differences in market design and governance that have real impacts but may not be readily quantified or reflected in production cost studies."

Seattle City Light (SCL), which largely has been alone amongst Northwest publicly owned utilities in urging BPA to join EDAM, had a different take.

"BPA has a fiduciary obligation to carefully weigh the variables and impacts to its customers before making any market decision," an SCL spokesperson said in an email. "BPA's own analysis shows that Markets+ is $221M in fewer benefits for BPA and its customers. BPA's statement that the updated E3 results have not shifted its recommendation to join Markets+ indicates that customer benefits impacts are not an important consideration in its [day-ahead market] decision."

The spokesperson said SCL, which operates its own balancing authority area, has yet to decide on a day-ahead market and will make a choice only after receiving its own benefits study results from The Brattle Group later this year. ■

WAPA Sierra Nevada Region to Advance with EDAM

Move Smooths Way for BANC to Sign Implementation Agreement

By Robert Mullin

The Western Area Power Administration said Oct. 30 that its Sierra Nevada (SN) region will pursue "final negotiations" to join CAISO's Extended Day-Ahead Market (EDAM), notching another — if expected — victory for the ISO in its competition with SPP's Markets+.

SN already participates in CAISO's Western Energy Imbalance Market (WEIM) through its membership in the Balancing Authority of Northern California (BANC).

BANC and its largest member, Sacramento Municipal Utility District, were last year among the first entities to announce their intent to pursue membership in the EDAM, after PacifiCorp. (See *BANC Moving to Join CAISO's EDAM*.) BANC members Modesto Irrigation District and the cities of Redding and Roseville have since committed to joining the market.

A commitment from SN would clear the way for BANC to sign an EDAM implementation agreement with CAISO, a well-placed source told *RTO Insider*.

With WAPA's approval, BANC expects to join the EDAM in the spring of 2027, the BA said in an Oct. 30 press release.

As part of federal power marketing administration (PMA) WAPA, SN sells low-cost power to irrigation districts, joint power agencies, cities and towns, public utility districts and other public entities from hydroelectric dams operated by the Bureau of Reclamation in the Central Valley Project, including Shasta (676 MW), Trinity (359 MW), New Melones (283 MW) and Folsom (199 MW).

"Working closely with the Balancing Authority of Northern California and our Sierra Nevada customers every step of the way, my staff and I look forward to engaging with CAISO through final negotiations to join this promising day-ahead market development," WAPA Administrator Tracey LeBeau said in a separate release. "Our dedicated staff will continue to solidify our working partnerships with BANC, customers and CAISO and resolve technical implementation details while ensuring the best possible outcomes for our customers and other stakeholders."

"We have concluded that participation in EDAM provides the best benefit for BANC and its WEIM participants while leveraging the investment we have made, and preserving the benefits we see, in WEIM," BANC General Manager Jim Shetler said in a statement. "This decision is also consistent with BANC's position that evolutionary development of markets in the West provides the most long-term durability. BANC looks forward to collaborating with WAPA-SN and our members as we move forward with EDAM implementation."

Shetler is a member of the West-Wide Governance Pathways Initiative's Launch Committee, which for the past year has been developing a proposal to establish an independent "regional organization" (RO) to assume governance of CAISO's WEIM and EDAM. SN's membership in EDAM could have at least a minor impact on the governance of the proposed RO, given that the most recent Pathways proposal reserves one seat for PMAs on the RO's Stakeholder Representatives Committee in either the WEIM or EDAM sectors. (See *Revised Pathways Proposal Focuses on Sector Issues*.)

In addition to marketing generation from the Central Valley Project Dams, SN also controls portions of the 500-kV Pacific Northwest-Pacific Southwest Intertie, which links the Bonneville Power Administration's territory in Eastern Oregon with Los Angeles, and the 500-kV California-Oregon Transmission Project linking Southern Oregon with California's Central Valley. Both lines are vital for moving energy back and forth between the Pacific Northwest and California and the Desert Southwest.

Altogether, the agency operates 884 miles of transmission ranging from 69 to 500 kV and 18 substations.

"Integrating WAPA's Sierra Nevada region along with BANC into EDAM is a crucial step towards realizing the vision of a fully integrated regional market," said Elliot Mainzer, president and CEO of CAISO. "Uniting resource-diverse utility partners across the West will enhance reliability, affordability and transmission connectivity. We are thrilled to see our valued partners taking these steps to solidify their position in this market at such a pivotal time." ■

Why This Matters

WAPA's decision to allow its Sierra Nevada region to move ahead with EDAM continues the momentum for CAISO in its competition with SPP's Markets+.

WAPA's Shasta Dam in Northern California | *WAPA*

CAISO/West News

California Labor, (Possibly) Public Power to Sponsor Pathways Bill

Sharp Turnabout for 2 Groups Staunchly Opposed to Prior CAISO 'Regionalization' Efforts

By Robert Mullin and Ayla Burnett

SACRAMENTO, Calif. — A representative of one of the staunchest opponents of past efforts to transform CAISO into an RTO said his labor union plans to sponsor the California legislation needed to implement the "Step 2" proposal of the West-Wide Governance Pathways Initiative.

On top of that, another previous objector to CAISO "regionalization" — a coalition of California's publicly owned utilities — signaled it might sign on as co-sponsor.

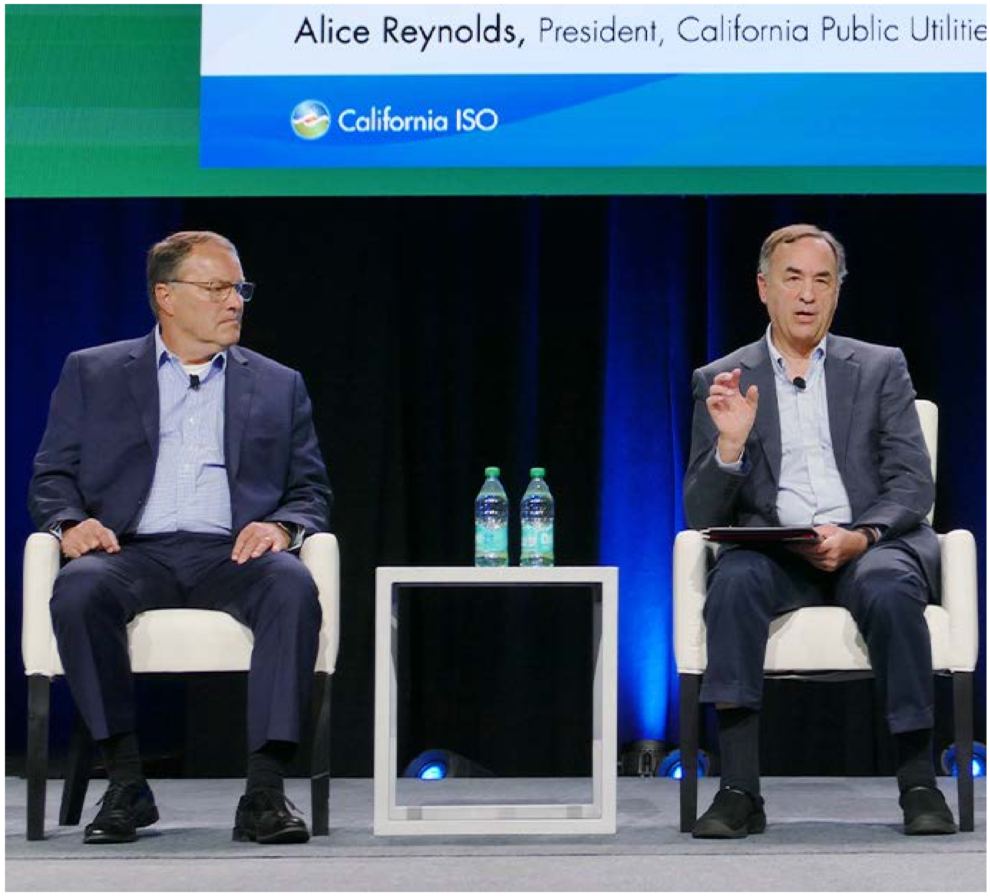
"I am very happy to say that we will be sponsoring the bill in the next California legislative session to implement the Pathways proposal for the CAISO and for the California utilities," Marc Joseph, an attorney representing the International Brotherhood of Electrical Workers (IBEW), said Oct. 30 during a panel discussion at the CAISO Stakeholder Symposium in Sacramento.

Joseph noted he'd sat on the stage at the same CAISO event eight years earlier to voice concern about the first of three attempts to regionalize the ISO through bills that would've transformed the California grid operator into an independent entity by eliminating the state's role in appointing its Board of Governors.

"This would mean that all of the functions of the CAISO would be removed from California control with no idea what would happen to them, and no chance for California to go back if we didn't like the outcome," Joseph said. "The legislature was in effect being asked to mortgage the farm with nothing more than 'trust us' as collateral."

Why This Matters

Opposition from California labor groups and POUs effectively killed previous legislative attempts to regionalize CAISO. Their strong support for a bill necessary to implement 'Step 2' of the Pathways Initiative bodes well for the newer effort.



Randy Howard of NCPA (left) and IBEW attorney Marc Joseph during an Oct. 30 panel discussion at the CAISO Stakeholder Symposium in Sacramento, Calif. | © *RTO Insider LLC*

That approach was "a particular problem" for California labor groups because the state's renewable portfolio standard (RPS) is "anchored" in the CAISO balancing authority area, requiring that a certain portion of new renewables be built in-state and directly interconnected to that BAA.

"If the CAISO became the RTO for the West, that could mean that the balancing authority area would be the entire West, and that would mean that the RPS structure would effectively be meaningless and most of the jobs for people in California would probably be exported to other states," Joseph said.

The Pathways proposal is different, he said, because it proposes to create a new independent "regional organization" to govern rules for CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) while leaving the ISO's BAA intact, a point Joseph and other labor representatives have emphasized previously, including in front of California lawmakers. (See *Pathways Initiative Releases 'Step 2' Proposal for Western 'RO'* and *California Labor Groups Affirm Support for Pathways Proposal*.)

Heading off questions about the bill's legislative author and its specific language, Joseph jokingly said: "Cool your jets. This is still October. It's only been 30 days since the governor finished signing the bills from the last legislative session. We are ahead of schedule, and we'll get to all of those things in due time."

'This is for Real'

When Joseph told Randy Howard, general manager of the Northern California Power Agency (NCPA), that IBEW planned to sponsor the Pathways bill, Howard said his first question was, "Who's the author?"

"And I said, 'I think we'd be interested in co-sponsoring,' which is a big shift for us in

CAISO/West News

public power," Howard said during the same panel.

NCPA represents 16 publicly owned utilities (POUs) in California, which are responsible for scheduling about 12% of the energy delivered into CAISO. Howard said public power's position on previous CAISO regionalization efforts largely aligned with that of labor.

"When we've looked at previous proposals related to an RTO — and the legislation, similar to [Joseph], we saw many more risks than we could identify benefits. And again, once you hand over the keys to the organization, you couldn't take them back," he said.

Howard said that, for public power, years of regional collaboration through CAISO's WEIM eased utilities' distrust stemming from the Western energy crisis of 2000/01. NCPA members prefer an "incremental" approach to developing a Western market, which the Pathways proposal continues to accommodate, he said.

As nonprofits, Howard said POUs are concerned primarily about maintaining reliability while keeping costs down. And while the publics would like to own all of their resources, that's not practical, he said, and participation in a broader day-ahead market like EDAM would provide access to a greater pool of resources at a lower cost.

"And by having this more efficient market and the market platform, we should be able to continue to add these emission-free resources and do it in a way that we can share them across the West with each other, diversify greater and try to keep the rates more affordable for our ratepayers, because that's what we think is the most important thing," Howard said.

Panel moderator Kathleen Staks, executive director of Western Freedom and co-chair of the Pathways Launch Committee, remarked about the progress the initiative has made in the year since it was formally launched.

"I think it has really sort of sunk in for us, [and] for the audiences that we've been talking with, that this is very real. This is a real proposal, and now we've just made it even more real," Staks said.

Speaking a week earlier on a panel at the fall joint meeting of the Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB), Staks said she was "cautiously optimistic" about passage of the Pathways bill.

Reached for comment on the floor of the symposium, Joseph told *RTO Insider* he sees "nothing uniquely challenging" about passing the Pathways bill compared with "any other substantial bill."

"In fact, because there is such widespread support for it, I think there's every reason for it to be successful," he said. "The single most important fact is that the leading opponents to prior rounds — labor and POUs — are now potentially sponsoring," he said.

Joseph confirmed the legislation will be introduced during the next legislative session, which begins in January.

And he reiterated the point made by Staks.

"The level of engagement is an indication that everybody recognizes this is for real." ■

NM PRC Issues 'Guiding Principles' for Electricity Market Participation

New Guidance Doesn't Prevent PNM from Announcing Day-ahead Decision This Year

By Elaine Goodman

Gabriel Aguilera, New Mexico PRC. | © *RTO Insider LLC*

As New Mexico utilities prepare to choose either CAISO's Extended Day Ahead Market (EDAM) or SPP's Markets+, the state's Public Regulation Commission has issued a set of principles intended to guide their decision.

The commission voted 3-0 on Oct. 31 to adopt the *guiding principles*, which emphasize customer benefits, transparency, stakeholder involvement and tracking of greenhouse gas emissions.

The guiding principles — which apply to Public Service Company of New Mexico (PNM) and El Paso Electric Co. (EPE) — are advice rather than a mandate for steps to take in choosing a day-ahead market. And they don't preclude PNM from making a market choice this quarter, as the utility has said it intends to do, commissioners said.

"To be clear, there are no requirements in this document," Commissioner Gabriel Aguilera said. "And there's nothing in this document that stops PNM from announcing a decision."

EPE has said it hopes to make a day-ahead market decision by the third quarter of 2025.

Some parties had recommended that the commission conduct a rulemaking to establish a process and requirements for market participation. Commissioners opted not to do so, saying they didn't want to create barriers to PNM making a day-ahead market decision this year. Rulemaking is still an option for the future, the commission said.

5 Principles

The first of the commission's five guiding principles is that the primary driver of any market decision must be customer benefits, with economic and reliability benefits as a priority.

The commission provided a list of factors to use in determining whether a particular market decision will benefit customers. Those include the market's expected footprint, its governance, and the cost and ease of market entry and exit.

Other factors are how transmission rights and congestion costs would be handled, and whether EDAM, Markets+ or the status quo show the best results in a cost-benefit analysis.

In the second principle, the commission said a utility's market participation should allow for sufficient tracking and reporting of greenhouse gas emissions to demonstrate compliance with the state's Energy Transition Act.

Thirdly, the commission said, the day-ahead market should have a fair and transparent decision-making process that "facilitates diverse and meaningful stakeholder engagement and considers stakeholder input fairly."

A fourth principle states that a utility's decision to join a regional market should include stakeholder input. The utility should make the study assumptions and results it is relying on available to regulators and stakeholders.

In the final principle, the commission asked utilities to provide updates on their market participation, including any major changes to the market and opportunities for stakeholder involvement.

After a utility has joined a day-ahead market, the commission would like quarterly reports for the first two years and annual reports thereafter.

Yearlong Process

Adoption of the guiding principles comes after the PRC opened a docket in August 2023 to examine factors PNM and EPE should consider when deciding whether to participate in a regional day-ahead market or RTO.

The commission held a series of workshops to discuss market participation. During an Aug. 29 workshop, The Brattle Group presented results of a study conducted for PNM and EPE, showing the utilities' projected benefits from joining either EDAM or Markets+.

The study modeled a scenario in which three Arizona utilities — Arizona Public Service, Salt River Project and Tucson Electric Power — join Markets+.

Even with the Arizona utilities in Markets+, projected annual benefits for PNM would be \$20.5 million if it joined EDAM, compared with \$8 million from participating in Markets+. For EPE, projected benefits were \$19.1 million a year for EDAM versus \$9.1 million for Markets+. (See *Brattle New Mexico Study Shows EDAM Benefits Outpacing Markets+*.)

Aguilera, who led the proceeding, said the process leading to the guiding principles had been successful in creating a forum where utilities, commissioners and stakeholders could learn what each other was thinking in terms of regionalization.

"The last thing that I wanted was a surprise filing or unexpected press release from the utilities announcing they are joining 'X' day-ahead market," he said. ■

Western Utility CEOs Reflect on Evolving Energy Markets

By Ayla Burnett

SACRAMENTO, Calif. — Leaders of four large utilities reflected on the evolution of Western markets and looked toward the future at CAISO's Stakeholder Symposium on Oct. 30, emphasizing a shift toward more collaboration as large industry players choose which day-ahead market to join.

CAISO also announced the 10-year anniversary of the Western Energy Imbalance Market (WEIM), using it as a catalyst for conversation on what's to come.

"How should we be thinking about the evolution of the markets in the West?" Lisa Grow, president and CEO of IDACORP and Idaho Power, said while moderating a panel at the symposium. "There are a lot of topical issues that we're all thinking about and that surround the day-ahead market formation."

Sitting on the panel was Cindy Crane, CEO of PacifiCorp; Tracey LeBeau, CEO of the Western Area Power Administration (WAPA); Dawn Lindell, CEO of Seattle City Light; and Caroline Winn, CEO of San Diego Gas & Electric (SDG&E).

PacifiCorp committed to join CAISO's Extended Day-Ahead Market (EDAM) in April; Seattle City Light has signaled its intent to join; and SDG&E will join by default via its membership in CAISO. WAPA announced plans in October to study the benefits of joining.

PacifiCorp and SDG&E feel confident in the transition from WEIM to EDAM, citing CAISO data showing $6 billion in benefits from the WEIM since its inception and $1.4 billion in benefits in a fully implemented EDAM.

"We're all in about creating more savings for our customers, and as we think about the grid development in the West and all of the investments that still need to be made for climate change, the clean energy transition and electrification, our customers need the savings to help offset some of those costs," Winn said. "I just can't think of a better time to really pursue EDAM."

Studies done for PacifiCorp also demonstrated substantial benefits for customers by joining EDAM, Crane said.

"We just recently updated our EDAM study, and those studies have done nothing but substantiate that this is the best move for these markets in the West," Crane said. "We firmly believe that EDAM will be a very successful and advanced energy market, and that it's going to be what provides the ability for the sector to achieve and overcome the challenges that we currently have."

Some utilities indicated interest in EDAM but have not yet committed. In October, a group of Arizona cooperatives that account for 70% of WAPA's Desert Southwest load announced a plan to study the benefits of joining EDAM. (See *Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study*.) The Brattle Group is doing a study for Seattle City Light that will evaluate the benefits of joining EDAM or SPP's Markets + that is expected to be published in December.

For those that have yet to formally commit, leaders agree that choosing a market that will bring the most value and connectivity to customers, as well as accelerating decarbonization efforts, is top of mind.

From left: PacifiCorp CEO Cindy Crane, WAPA CEO Tracey LeBeau and Seattle City Light CEO Dawn Lindell. | © RTO Insider LLC

Why This Matters

The competition between CAISO's Extended Day-Ahead Market and SPP's Markets+ is one of the most important conversations in the industry today, and the perspectives of leaders from four of the biggest utilities in the West could influence others' decisions on which day-ahead market to join.

"We're in the throes of our decision-making, and customer-benefit analysis will be key in deciding what market we go to," Lindell said.

'The Fewer Seams, the Better'

Market seams are bound to be an inevitable challenge, as it may be more difficult to trade power to and from balancing authority areas operating in different day-ahead markets.

The CEOs emphasized the importance of collaboration through seams agreements, especially to support each other through increasingly frequent extreme weather events.

"We're committed, first and foremost, to making sure that we have seams agreements in place," Crane said. "But [seams] do create a loss of efficiency in the system. And seams agreements don't overcome the loss of efficiency."

WAPA shares a seam with MISO, and while LeBeau said it isn't ideal, "it's been going pretty well." She pointed to the relationship that has been developing between MISO and SPP as a good example of collaboration for the West to follow.

Lindell agreed that the "fewer seams, the better," pointing again to the inefficiencies they create, as well as the rise in risk for speculative trading and overall increased costs.

"We all operate parts of, I think, the most complex machine that humans have ever built, and it requires collaboration and coordination," Winn agreed. "There's some competition that's built into the markets, for sure, but having spent most of my life in this industry, it's such an honor to be able to serve in that way and provide such a basic service that everyone relies on." ■

ISO-NE News

ISO-NE Study Lays Out Challenges of Deep Decarbonization

By Jon Lamson

Deep decarbonization of the New England grid will pose major challenges related to resource adequacy and market administration, ISO-NE concluded in the *final report* of its Economic Planning for the Clean Energy Transition (EPCET) study, released Oct. 24.

The RTO emphasized the importance of developing dispatchable zero-carbon resources to ensure reliability during extended periods of low wind and solar generation, and said new mechanisms likely will be needed to support dispatchable resources that run only in extreme scenarios.

ISO-NE previously outlined its key findings at its Planning Advisory Committee in August, when it told stakeholders it plans to consider "future market rule enhancements to support the ongoing reliability and economy of the region's grid." (See *ISO-NE: New Mechanisms May be Needed to Ensure Future Grid Reliability*.)

One of the main issues New England will face as it approaches full decarbonization is increasing variability of both demand and supply, with electrified heating and intermittent renewables both highly impacted by extreme weather events, ISO-NE wrote.

"The magnitude of the annual peak will vary dramatically from one year to the next, depending on how cold or how mild a winter the region sees," ISO-NE wrote. "As a result, some resources needed to maintain reliability during the harshest conditions may only run once every few years."

Without significant dispatchable resources, decarbonization will require a significant overbuild of wind, solar and batteries, which would come at a significant cost to consumers and have a large land-use impact, ISO-NE said.

The RTO estimated the region would need to add a staggering 97 GW of renewable capacity by 2050 to meet state goals, equating to an average annual addition of 1,293 MW of offshore wind, 268 MW of onshore wind, 955 MW of solar and 952 MW of batteries.

As the proliferation of renewables eliminates power system emissions from increasing amounts of the year — first in the spring and fall seasons, followed by the summer and eventually the winter — the value of new renewables will decrease, the modeling found.

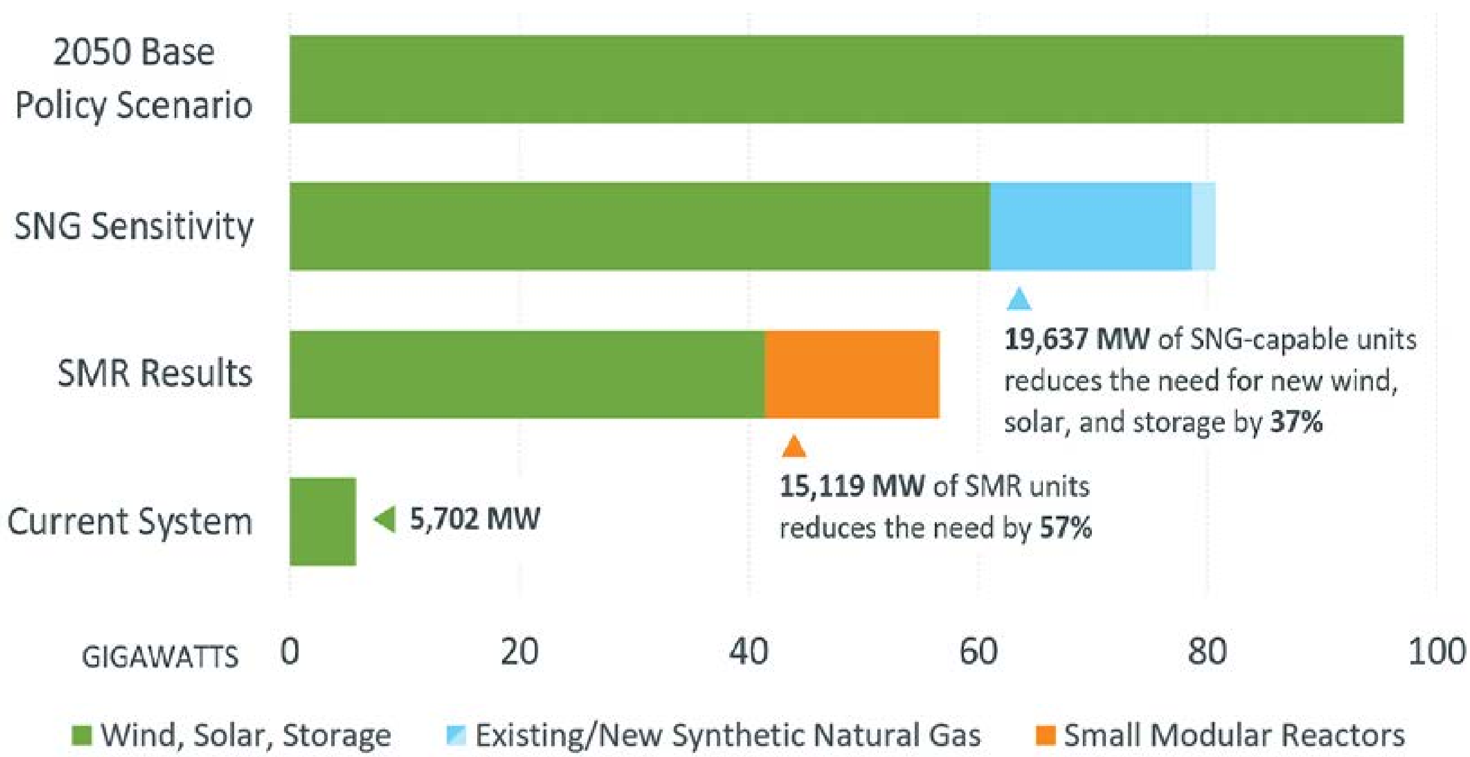
"Fundamentally, as decarbonization accelerates, but remains highly correlated with the seasons, zero-carbon resource additions will produce surplus energy for increasing periods of time, and their cost per MWh will rise," ISO-NE said.

Why This Matters

Meeting state decarbonization goals likely will require a combination of new market structures and technologies to avoid runaway costs or excessive reliability risks, ISO-NE found.

The declining value of additional renewables will correspond with the increasing need for dispatchable resources and long-duration storage, ISO-NE said. The RTO found 100-hour batteries — such as those planned for development in Maine — will become particularly valuable as the region approaches 2050.

"However, even with a significant penetration of 100-hour batteries, the later years of this sensitivity still experience stretches of time when 100-hour batteries become depleted and significant fuel-secure dispatchable gen-



Resources needed to meet state decarbonization goals | *ISO-NE*

ISO-NE News

eration is needed to satisfy demand," ISO-NE said.

To address these gaps, ISO-NE highlighted low-carbon fuels such as synthetic natural gas (SNG), clean hydrogen and renewable diesel, as well as small modular reactors (SMRs), as potential options.

The RTO specifically modeled SNG, noting that it could make use of the existing gas transmission network, while hydrogen likely would require significant amounts of new storage and transportation infrastructure.

It found that including 19,637 MW of SNG resources "achieves the states' 2050 decarbonization targets while requiring 37% less new renewable capacity," with high SNG fuel costs offset by the diminished need to overbuild renewables.

ISO-NE also modeled the effects of including SMRs, finding that "a renewable-dominant build-out that also includes 15.1 GW of SMRs achieves the states' 2050 decarbonization targets while requiring 57% less new renewable capacity."

The RTO emphasized that cost projections for SMRs remain highly uncertain, but estimated the inclusion of SMRs could reduce overall capital costs by 33% relative to the base case, and said the SMR case still outperformed the base case when the model doubled the SMR cost assumption.

The report did not include a focus on how increased interregional transmission could affect the system. Multiple studies have found increased transmission between Québec and New England to reduce the cost of deep decarbonization in the Northeast by enabling Québec's hydroelectric resources to balance out intermittent renewables. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

Massachusetts Institute of Technology researchers have *found* that increased bi-directional transmission between the U.S. and Canada would cut overall decarbonization costs by reducing the need to overbuild renewables. The researchers *estimated* that 4,000 MW of additional transmission between New England and Québec would reduce the overall costs of full decarbonization by 17 to 28%.

ISO-NE also noted that increased demand flexibility, which has been a top priority for consumer and climate advocates in the region, likely would not provide significant benefits during extended winter periods of low wind generation.

"While EV charging or heating could be delayed by a few hours, heating in particular cannot be delayed for longer time periods," ISO-NE wrote.

Minimum Load Concerns

The RTO also noted the proliferation of behind-the-meter solar could create minimum-load issues for resources that are not able to quickly ramp down their production.

"All weather years in the modeled 2032 system experience days in which the net load falls below this threshold," ISO-NE found.

It noted that flexible load — such as demand from electric vehicle charging — could be incentivized to alleviate these issues, or the region could increase its exports if other regions are not facing similar conditions.

Market Challenges

Beyond the technical challenges of developing adequate dispatchable zero-carbon resources to support system reliability, significant changes to the current market structures likely will be needed to support these resources, ISO-NE said.

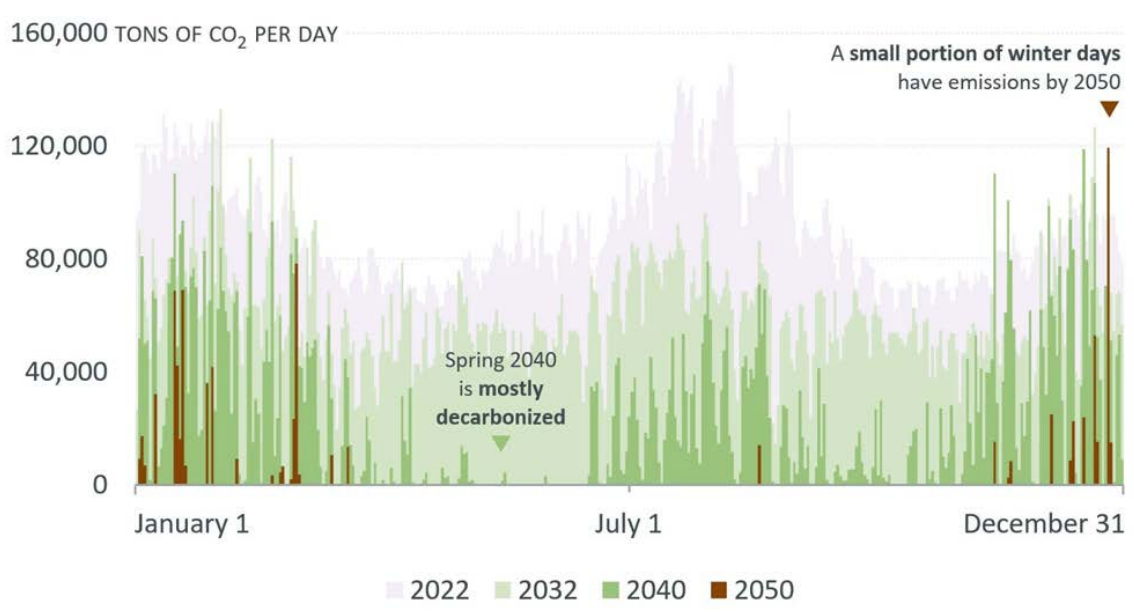
While the energy market currently is ISO-NE's largest market "by a large margin," RTO projects overall revenue from the capacity market and from state power purchase agreements (PPAs) to surpass the energy market by 2035. Meanwhile, the proliferation of resources with PPAs — which often still can profit when bidding negative prices into the energy market — could threaten the viability of baseload resources that lack PPAs.

"Baseload nuclear resources are at particular risk of exposure to periods of negative [locational marginal prices], since they cannot increase or decrease their output quickly," ISO-NE said.

Meanwhile, dispatchable resources needed to ensure reliability may not be used at all within a given year, putting more pressure on the capacity market to provide them with the necessary revenue. ISO-NE officials previously expressed apprehension about relying too heavily on the capacity market, which frequently is subject to intense stakeholder debates.

"Current market rules and other revenue structures may not scale well in a renewable-heavy grid, and the ISO is exploring alternate market structures within its jurisdiction," ISO-NE wrote.

ISO-NE CEO Gordon van Welie has frequently expressed his support for developing a price on carbon within the wholesale markets but has said this would require full support from all six New England states. The EPCET study noted that zero-carbon dispatchable resources likely would need a price on carbon, or some other incentive, to compete economically with fossil alternatives. ■



Projected tons of carbon per day | *ISO-NE*

MISO News

MISO IMM Makes Closing Arguments Against $21.8B Long-range Tx Plan

Members Argue LRTP Necessary, Market Monitor's Attempt to Influence Transmission Planning Improper

By Amanda Durish Cook

A portion of the Cardinal-Hickory Creek line passing the Badger solar fields in Grant County, Wis. | *ATC and ITC*

MISO Independent Market Monitor David Patton has made a final stand against the RTO's $21.8 billion long-range transmission plan (LRTP) portfolio, asking MISO board members to order a postponement of the transmission portfolio and direct MISO to condense projects.

The appeal led multiple stakeholders to tell the MISO Board of Directors that the IMM should end his foray into MISO's transmission planning and stick to supervising markets.

The showdown came as MISO advances its 2024 MISO Transmission Expansion Plan (MTEP 24) to its board of directors.

This year, MISO and members will vote on more than the traditional MTEP lineup. The MTEP 24 umbrella also officially includes the $21.8 billion LRTP and the $1.65 billion Joint Targeted Interconnection Queue (JTIQ) portfolio in partnership with SPP.

MISO staff have called the $30 billion collection historic.

In September, MISO's Jeremiah Doner said even MTEP 24's $6.7 billion of traditional local spending is a "sizable amount of investment occurring." The traditional MTEP 24 includes 459 projects, with total lines spanning 932 miles.

Traditional MTEP 24 spending is smaller than last year's $9.2 billion. And while a good chunk of MTEP 23 was devoted to local reliability needs, this year's investment is driven by age condition projects and load growth.

However, it's the second LRTP portfolio that's soaking up all of the attention this year.

"Let me say at the outset: this is probably the least satisfying exercise I've taken part in. I take no pleasure in being critical of such an important process," Patton told board members during an Oct. 30 teleconference of the System Planning Committee of the MISO Board of Directors. He added that he thinks transmission expansion is essential.

"We believe there are portfolios of transmission investment that will be extremely beneficial … but this portfolio is not that portfolio," Patton said.

Patton said the "costly" portfolio represents a present value of $2,600 per family in the Midwest.

"Hence, it is critical that the analysis be objective, accurate and unbiased," he said.

Patton said though he's been raising concerns with the second LRTP portfolio for two years, MISO hasn't addressed his fault-findings. MISO and the IMM have disagreed publicly on the LRTP often over the past several months. (See *MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops* and *MISO, Monitor at Stalemate over Need for $21B Long-range Tx Plan*.)

Patton said he wasn't trying to thwart a second LRTP but that he wanted MISO to develop a leaner portfolio with downsized projects.

He said MISO's two most flawed benefit metrics are the mitigation of reliability issues and the avoided construction of new capacity MISO estimates the portfolio will deliver on. He said if those two benefit calculations are downgraded to more reasonable outcomes, the benefit-to-cost ratio of the LRTP portfolio would be anywhere from 0.4 to 0.7:1.

MISO anticipates a benefit-to-cost ratio of between 1.8:1 and 3.5:1 over the first 20 years of the projects' lives through reliability improvements, production costs, new capacity that won't have to be built and environmental benefits.

Patton has said repeatedly MISO is incorrect in assuming reliability issues in the footprint would become so dire that MISO should use its $3,500/MWh value of lost load as an indicator of savings. He said a more reasonable notion is that MISO would take operational actions to

Why This Matters

MISO and its Independent Market Monitor remain at loggerheads over the need for the RTO's $21.8 billion long-range transmission portfolio. The IMM has asked MISO board members to postpone the expansion package, while some stakeholders contend it's improper for the Market Monitor to reach into transmission planning. The portfolio's approval is coming due in early December.

MISO News

address reliability risks.

Patton also said that MISO's capacity expansion modeling is fundamentally flawed, favors intermittent resources and doesn't consider what resources will be built and where if MISO doesn't build the second LRTP portfolio. Patton said if MISO tested against a but-for scenario where there is no LTRP II, the footprint "rationally" would experience more capacity development in the eastern part of the footprint versus more remote, intermittent resources built in the western portion. He said any reasonable utility would choose to build deliverable megawatts without the transmission.

Patton likened MISO's estimated benefits to trying to convince his wife to agree to buying him a new car instead of getting brake repairs performed on his existing car through the argument that his life would be at risk.

"That's the logic you have to adopt: What is the alternative?" he said.

Planners Defend Portfolio

Senior Vice President of Planning and Operations Jennifer Curran said Patton and MISO philosophically disagree on the need for the LRTP portfolio.

"When we think about the resource expansion, we have a different idea about the goals of our customers and what our members are trying to achieve," she said. "Where we agree is that we definitely need to do what's best for our customers. That's at the forefront."

Curran said MISO requires backbone transmission and that waiting risks reliability and leaving the system expansion to less valuable, piecemeal transmission solutions.

"We cannot wait for the certainty of resource types to build transmission," she said.

Curran said members' stated goals provided the thrust for the portfolio. She stressed that MISO did not overstep its role as a transmission planner and not a resource planner.

"We are talking about the highway transmission and not the side streets," she said.

Curran said MISO probably is being conservative in the reliability benefits and likely understating the help transmission would provide during extreme weather events. She said MISO stands ready to testify to the need for the transmission in front of state regulatory commissions.

Vice President of System Planning Aubrey Johnson said that the collection of 24 projects would create a backbone of mostly 765-kV transmission across the Midwest. He said MISO's aims with the portfolio aren't to address one NERC criteria at a time but "reliably enable" the resource planning its members have indicated. Johnson acknowledged that goal does shift the portfolio into "uncharted territory."

Johnson noted that MISO planners made more than 500 adjustments to capacity expansion siting based on MISO members' counsel.

Executive Director of Transmission Planning Laura Rauch said there are almost certainly additional benefits beyond those that MISO monetized in its business case, including more reliability and efficiency value and expanded transfer capability. Rauch said LRTP II will enable the sweeping flows that help keep the lights on during heat domes, derechos and ice storms.

MISO board members withheld their opinions on the LRTP and asked mostly clarifying questions on Patton's criticisms and MISO's process. They did not publicly address Patton's appeal for a pause on the LRTP approval process.

"Is there a sense of, 'don't build and this [capacity] will evolve?'" board member Phyllis Currie asked of stakeholders' attitudes across the 300-plus public meetings MISO held during the development of LRTP II. She said her question "strikes at the role of MISO" as a transmission planner and keeping out of resource planning.

Johnson said stakeholders generally were supportive of MISO's direction on planning and confirmed to MISO that the proposed lines followed their burgeoning resource plans.

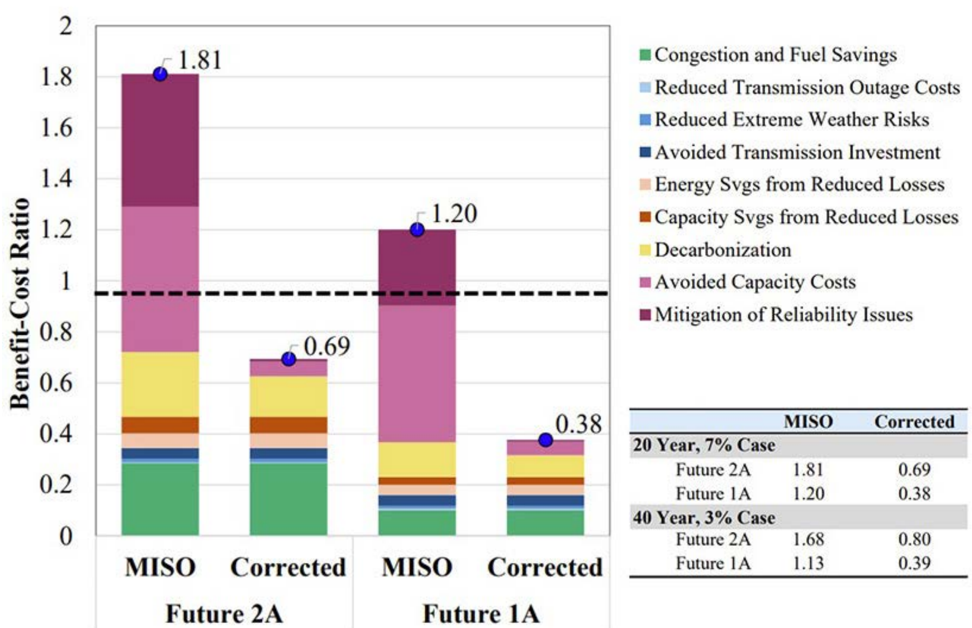
Board member Trip Doggett invoked a recent Grid Strategies *report* that placed MISO and CAISO at the top of regional planning efforts in the country, giving each a 'B.' Doggett asked what MISO should do to reach 'A' status. Curran said MISO's grade boils down to the LRTP not yet extending to the MISO South region.

The System Planning Committee is set to hold a vote on whether to recommend MTEP 24 along with LRTP II at a Nov. 19 teleconference.

Chorus of Support, Some Detractors and Complaints that IMM has Overstepped

Most public comments after the IMM and MISO delivered their positions provided support for the LRTP, with multiple stakeholders telling MISO board members that the IMM shouldn't be influencing transmission planning.

Michigan Public Service Commission staffer Erik Hanser said Patton is mistaken that "market forces alone" can fill the need for transmission planning.



	MISO	Corrected
20 Year, 7% Case		
Future 2A	1.81	0.69
Future 1A	1.20	0.38
40 Year, 3% Case		
Future 2A	1.68	0.80
Future 1A	1.13	0.39

* MISO cases show the minimum value, affecting only 2 benefits by excluding the high-end carbon value and VOLL.

The MISO IMM's view of LRTP benefits in the second and fourth columns, which drastically reduce the portfolio's benefits of avoided reliability risks and avoided new build capacity | *Potomac Economics*

MISO News

Hanser also said Patton "bringing these issues up month after month" is not a good use of time for the Market Monitor, who he emphasized is not a transmission monitor. Hanser said he questioned how appropriate it was for the IMM to spend so much time and attention on an area outside of his market monitoring responsibilities.

Minnesota Public Utilities Commissioner Hwikwon Ham said MISO's long-range transmission planning allows state jurisdictions to carry out their resource planning. He also said MISO's comprehensive transmission planning saves ratepayers money over the long run.

American Transmission Co.'s Bob McKee said it's inappropriate for the IMM to think his opinion on planning should override those of the stakeholder community. McKee invoked the LRTP as "exactly the type of long-range planning" that FERC is requiring RTOs to engage in per Order 1920.

McKee also said that LRTP II will go a long way in addressing the "new, unforecasted, historic, large-point loads" that are cropping up on the system and are requiring several out-of-cycle transmission projects.

Natalie McIntire, of the Natural Resources Defense Council's Sustainable FERC Project, said the IMM simply seems opposed to top-down regional planning and said MISO is leading the industry in planning. She asked board members not to entertain the IMM's requests.

WPPI Energy's Steve Leovy, however, seconded the IMM's ask for MISO to test the LRTP against a future case where the second LRTP portfolio doesn't exist. He said the additional testing from MISO wouldn't usurp the role of resource planning or infringe on states' rights.

"Let's be clear: The debate we are having today is not about methodology. It's about ideology. And it's being driven by Dr. Patton in ways that I believe are inappropriate for his position. I believe he has abandoned his independent voice," Union of Concerned Scientists' Sam Gomberg said.

Gomberg said it's a "huge red flag" that Patton presented analytics showing the LRTP falls below worthwhile investment without documentation detailing his methods. MISO and stakeholders have "repeatedly suffered through" presentations on Patton's uncorroborated numbers, Gomberg said, while Patton at times "belittles" MISO's and stakeholders' perspectives.

"Throw out any number you like in a public setting as long as it's big enough to catch attention, let the media sink their hooks into it and the headline on the front-page reads: 'IMM Says MISO Transmission Plan isn't Worth It' while everyone else scrambles to explain after-the-fact why this number shouldn't be trusted," Gomberg told board members. "When this happens, it makes yours and every state regulator's job harder because it colors your and regulators' ability to do the proper, objective due diligence necessary to weigh the costs and benefits of these projects."

MISO's Aubrey Johnson | © *RTO Insider LLC*

Gomberg said the IMM's actions are "at best negligent and at worst a deliberate attempt to undermine the process." He said he "believes it's past time" for the MISO Board of Directors to "clearly and publicly" define the IMM's role in MISO transmission planning and hold him accountable to transparency standards and analytic rigor.

"The character assassination of Dr. Patton is really unfortunate," North Dakota Public Service Commissioner Julie Fedorchak said. "There's a lot of opportunity between doing nothing and spending $30 billion in transmission planning."

Fedorchak said MISO should listen to independent, third-party critiques that its LRTP business case is overblown.

"With these benefits, you could justify building just about anything," Fedorchak said, reminding board members that North Dakota doesn't have clean energy goals and it's unfair for the state to shoulder a portion of LRTP costs.

Kavita Maini, a consultant representing MISO industrial customers, also said she appreciated the IMM's request to take a hard look at the LRTP.

"We need an independent voice, and we appreciate the IMM's efforts," Maini said.

But Google's Tyler Huebner, said MISO's "effective, multi-value transmission planning" is vital and serves as proof that not all members in the end-use sector agree with one another.

Clean Grid Alliance's David Sapper said board members should "strongly" consider Google's support since the LRTP is rooted in a future view of the grid, implying that Google should know better than most what's to come.

ITC's Brian Drumm said MISO assembled the second LRTP portfolio with industry-tested practices and planning tools that are crucial to maintaining reliability as the clean energy transition and load growth knock on MISO's door.

"Now is not the time for us to slow down," he said, endorsing the LRTP.

Drumm also said Patton's "is just one voice" among hundreds of stakeholders who contributed to the multiyear development of the LRTP.

Great River Energy's Priti Patel said she likewise was lending support to LRTP II. She said Great River Energy independently tested the LRTP's business case and found that proposed lines in Minnesota best meet technical needs while minimizing impacts to communities across GRE's electricity cooperative.

"We see this is a significant and necessary step to maintaining future reliability," Patel said.

Xcel Energy's Drew Siebenaler encouraged MISO and its board to proceed with the LRTP as soon as possible.

"In my professional career, I've never encountered a stakeholder process that has had more hours and engagement as this," Iowa Utilities Board Member Josh Byrnes said of the journey to the second LRTP portfolio.

Byrnes said though "not everyone got what they wanted," the LRTP has struck a good balance in planning.

"I truly believe that doing nothing is probably not a good option for us," Byrnes said.

System Planning Committee Chair and MISO board member Mark Johnson thanked stakeholders for their perspectives.

"Today's session was really about gathering information before our session on Nov. 19," he said and concluded the meeting a full hour after it was scheduled to end. ■

MISO News

MISO and TVA Strike Emergency Energy Purchase Agreement, Request FERC OK

By Amanda Durish Cook

MISO and the Tennessee Valley Authority hope to implement an emergency energy purchase framework by Christmas Eve.

The two have filed an agreement before FERC for permission to be able to transact energy with one another during emergencies by Dec. 24 (*ER25-197*).

MISO and TVA have never had an agreement to mutually supply the other with emergency power, and they said they traditionally had "other arrangements" that seemed sufficient to meet the needs of their regions.

However, the two said the late December 2022 winter storm changed their views.

"Due to the changing configuration of the grid and recent emergency events, like Winter Storm Elliott, MISO and TVA have become increasingly focused on the need for additional coordination and planning to better ensure reliability in an emergency," MISO Managing Senior Corporate Counsel Amy Thurmond wrote to FERC in a transmittal letter. "To that end, each has identified the need to purchase emergency energy from the other to maintain the reliability of each individual transmission system and, more generally, the integrity of the Eastern Interconnection."

MISO and TVA have contemplated an agreement since MISO supplied up to 5 GW at times during the storm Dec. 23, 2022, to the Tennessee Valley Authority, SPP, Associated Electric Cooperative Inc. and the Southeast planning region. MISO's exports that day played a role in forcing its own maximum generation event. After, MISO leadership lamented that though MISO could assist TVA during dire straits, TVA was prohibited from returning the favor when MISO encountered precarious operations. (See *MISO, TVA to Enter Agreement on Emergency Purchases* and *MISO Defends Energy Exports During December Storm*.)

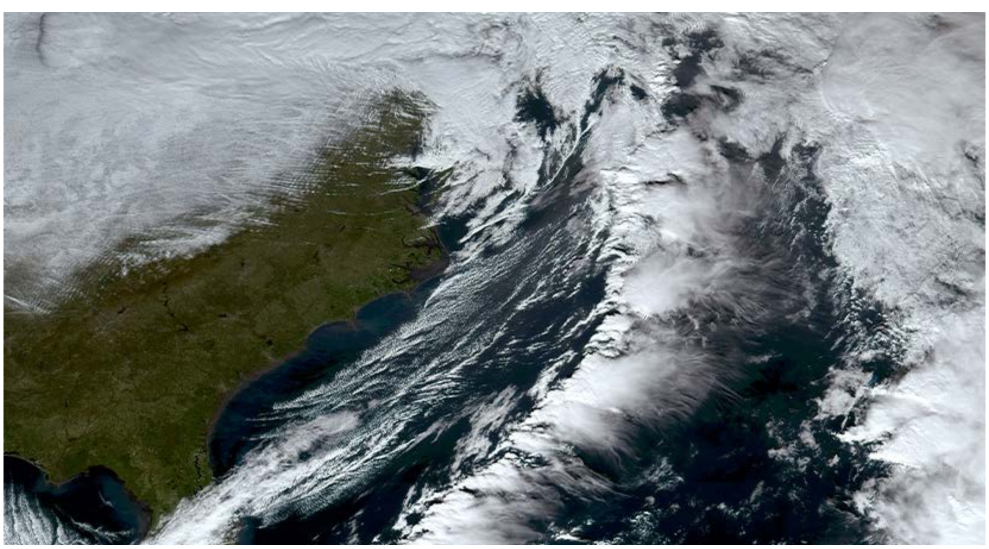
TVA's ability to provide power to parties outside of its service territory is limited by the *TVA Act*. The federal utility can supply power only to parties that held exchange power arrangements as of July 1, 1957, and their successors. TVA for years interpreted the TVA Act as a barricade to selling power directly to MISO.

MISO is less restricted in the balancing authorities it can sell to or purchase emergency energy from. The RTO's tariff requires only that there be an agreement between MISO and another BA.

MISO noted that two of TVA's neighboring electric systems included in the 1957 agreement — Ameren and Entergy — joined MISO years ago. MISO and TVA share a seam in Mississippi and along the Arkansas-Tennessee state line.

Ameren and Entergy as Avenues for Trade

The freshly filed agreement involves Ameren and Entergy granting authority to MISO to act on their behalf to buy emergency energy from TVA. MISO said the emergency energy it coordinates and directs from TVA on behalf of Entergy and Ameren would be used for the "sole purpose of maintaining electric reliability."



The December 2022 North American winter storm on Dec. 23, 2022 | *NOAA*

Why This Matters

If accepted by FERC, the agreement would mark the first emergency energy purchase arrangement between MISO and the Tennessee Valley Authority.

Terms of the agreement stipulate that TVA and MISO can share power up to the transfer limits in use between the two when one is experiencing an emergency. The two said supply to the other shouldn't come at the expense of the "safe and proper operation" of their own transmission systems and service to their own customers and shouldn't impede obligations they might have with other parties.

MISO and TVA said one or the other should be experiencing a NERC-defined Energy Emergency Alert Level 2 before an offer to supply emergency energy can be made. Offers would be recallable up to 10 minutes ahead of time, and MISO and TVA said they would make efforts to ensure that an emergency energy transaction "continues only until it can be replaced by a commercial transaction." All emergency energy transactions would be metered and billed based on scheduled deliveries. Emergency energy charges from the delivering BA to the receiving BA would be calculated based on a two-part formula that includes an energy portion and any transmission charges to an agreed-upon delivery point.

When MISO was the delivering BA, the rate per megawatt hour would be either 150% of the hourly locational marginal price at the buses near the point of exit, 110% of the verifiable cost of the resources used to supply the power or $100/MWh, whichever is greater. When TVA was delivering megawatts, the rate similarly would be the greatest of either 150% of the hourly LMP at the points of injection in either the Ameren or Entergy service territory, 110% of the verifiable cost of the resources used to supply the power or $100/MWh.

MISO and TVA plan to use an invoice system with rules that allow one or the other to collect interest on delinquent payments or raise billing disputes. MISO added that though it would be sourcing emergency energy on behalf of Ameren and Entergy, under no circumstances would the two members be liable for MISO's obligations under the agreement. ■

MISO News

Entergy CEO: Nuclear, Carbon Capture in Equation to Handle Industrial Growth

By Amanda Durish Cook

Entergy CEO Drew Marsh said the utility's third quarter contained yet more prep work for large industrial customers and development for carbon capture alongside more nuclear and solar generation.

Marsh estimated Entergy's compound annual growth rate in industrial sales at 11 to 12%, 300 basis points higher due to a large new industrial customer that recently signed a 15-year electric service agreement with Entergy Louisiana.

"We don't disclose specific customer details without their consent, so we can't provide additional information at this time," Marsh said during an Oct. 31 earnings call.

Marsh said the major customer will bring economic activity to a portion of northern Louisiana "that has been economically disadvantaged for decades."

Although no docket in the case is available yet at the Louisiana Public Service Commission, Entergy has shared a redacted *version* of its application for approval of generation and transmission to host an "economically transformative" $5 billion investment the unnamed customer is looking to site in Richland Parish. The utility hopes to build three new combined cycle combustion turbines and a 500-kV line.

Entergy reported third-quarter earnings of $2.99/share and third-quarter net income of $644.9 million, down year-over-year due to 2023's exceptionally hot summer in the South.

However, Marsh said Entergy had a "very productive quarter" marked by higher industrial sales and growing demand for clean energy.

Marsh said other large industrial customers increasingly are looking to Entergy for zero-carbon energy offerings.

"Collectively, this means that our preliminary capital plan through 2028 is $7 billion higher than on Analysts' Day, driven by new transmission as well as incremental new generation investment, including renewables," he said.

At Entergy's annual Analysts' Day in June, the utility *announced* a $33 billion, five-year capital plan.

Marsh noted that Entergy Arkansas' 100-MW Walnut Bend Solar farm, built in partnership with Invenergy, was placed in service during the quarter, and Entergy Arkansas also closed on its 180-MW West Memphis Solar and 250-MW Driver Solar facilities.

Marsh said Entergy now has nearly 800 MW of solar resources in service and close to 2.6 GW of solar projects "in process, approved or under regulatory review."

Marsh said Entergy plans to build even more customer-driven renewable energy sources, mentioning Entergy Louisiana's request for proposals to acquire 3 GW of new solar.

He also noted that Entergy Mississippi announced plans this quarter to build a 750-MW dual-fuel, combined cycle plant, its first new natural gas power station in 50 years. He said the plant will be hydrogen ready and designed to be outfitted eventually with carbon capture technology.

Marsh said Entergy is gearing up for carbon capture and storage (CCS) to take a role in the clean energy transition and is in "active discussions with customers about "a variety" of low-carbon generation solutions, including carbon capture.

Marsh said Entergy Louisiana continues its front-end engineering and design study to evaluate the technical and financial feasibility of installing carbon capture at the Lake Charles Power Station, with Entergy enlisting the help of Crescent Midstream.

"Once completed, the learnings from this work will benefit future CCS projects. Ultimately, we believe CCS is a critical technology to comply with eventual federal emissions requirements, to help our customers meet their decarbonization objectives and for us to achieve our 2050 net-zero commitment," Marsh said.

Marsh indicated Entergy is ready to partake in the nuclear revival taking hold in the country.

Entergy believes nuclear power will factor heavily in its path to net-zero emissions by 2050 and is "well-positioned to evaluate and ultimately pursue new nuclear options," Marsh said.

Marsh said Entergy is actively exploring potential nuclear plant uprate projects that could add as much as 300 MW in capacity at the utility's Arkansas and Louisiana nuclear plants.

Marsh also brought up that Entergy since 2007 has held an early site permit from the Nuclear Regulatory Commission for a potential new reactor at its Grand Gulf nuclear site and invoked the utility's memorandum of understanding with Holtec International to evaluate small modular reactors.

During the past quarter, the Louisiana Public Service Commission unanimously approved a $95 million *settlement* with Grand Gulf owner and Entergy subsidiary System Energy Resources to resolve all complaints related to Grand Gulf's past performance lags. It also unanimously approved an agreement to divest Entergy Louisiana's share of Grand Gulf energy and capacity to Entergy Mississippi. (See *Entergy Touts Louisiana Settlements, Beryl Response in Q2 Earnings*.)

Entergy has submitted additional filings to the Mississippi Public Service Commission and FERC to approve the divestiture. ■

Entergy Arkansas' Walnut Bend Solar | *Entergy Arkansas and Invenergy*

NYISO News

New York DPS Recommends New Method for Determining Peak Hours

By Vincent Gabrielle

The New York Department of Public Service presented a *proposal* for updating the method by which NYISO determines peak load hours to the ISO's Installed Capacity Working Group on Oct. 29.

The change would not affect the capacity market load forecast or installed reserve margin and is only being proposed for transmission owners' capacity obligations to load-serving entities.

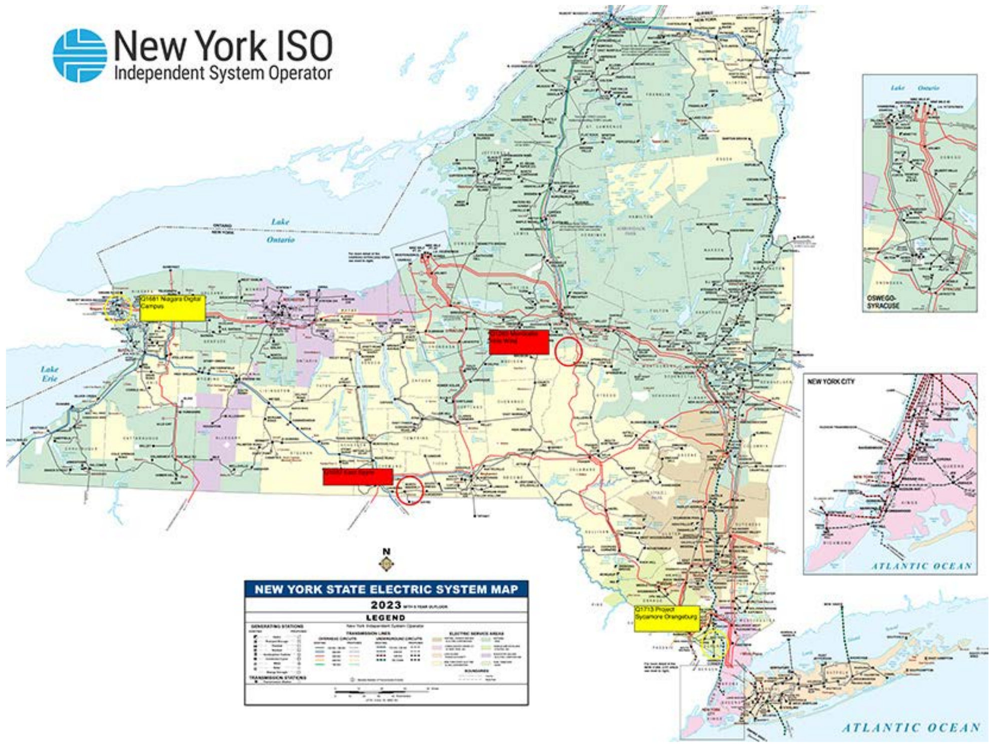
Chris Graves, chief of utility programs for the DPS Office of Regulatory Economics, explained that the department was recommending using the top 10 New York Control Area coincident peak load hours on non-holiday weekdays in July and August. This approach would provide a better allocation of capacity costs to LSEs and a more representative rate for retail customers, he argued.

"I want the demand side of the market to understand what hours are important so they can make decisions on how much capacity they want to be buying," Graves said.

In most years, based on historic data, the top 10 hours will occur on three or more days. In situations where the top 10 hours occur in two days, all zones tend to peak at the same time. Graves said that if the ISO is forced to always use the top three days, rather than just the top 10 hours, the weight of the peak would be diluted, and the peak hours might not be representative.

The effort to identify more peak load hours dates back to at least *2021* when NYISO was considering *expanding* to more peak load hours so that TOs could use the information when allocating load obligations to generators and other LSEs in the capacity market.

Current practice only identifies the peak hour using reconstituted load data. This means that capacity resources that are not visible to NYISO in the real-time market are added back into the peak load hour as part of the load forecasting process.



| NYISO

Graves said that there is currently no adjustment to add back generation from resources not participating in the wholesale market, like rooftop solar or municipal generators.

In July 2021, NYISO recommended using the coincident peak load from the highest hour of the top three unique peak load days on non-holiday weekdays in July and August using actual load data.

Stakeholders, squinting at dense slides, voiced some skepticism. One stakeholder asked whether this was just making determination of peak hours more complex than necessary.

"Wouldn't incentives be better if we set capacity accreditation factors in advance so people know what they are? If we set the weighting factors in advance, wouldn't that improve incentives for load?" they asked.

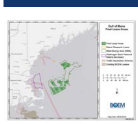
Graves said it could improve incentives, but he wasn't sure if it was cost-causative because the weightings change depending on the load shape.

Amanda De Vito Trinsey of Couch White, representing the large customer association Multiple Intervenors, said the group was "fiercely opposed" to the proposal.

Another stakeholder said that a straight average of 10 hours of load would "destroy the incentive to care about the actual peak" because averaging of that length of time would dilute the load.

"We got this yesterday morning, and we've been talking a bit, trying to noodle through this ... but it seems like more work needs to be done," they said. ■

Northeast news from our other channels



Gulf of Maine OSW Auction Results in Four Leases Worth $21.9M

NetZero Insider

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

NYISO News

NYISO Updates Stakeholders on Budget, 2025 Goals

By Vincent Gabrielle

NYISO headquarters in Rensselaer N.Y. | *NYISO*

NYISO on Oct. 28 *presented* additional data to the Budget and Priorities Working Group explaining its reasoning for rolling the remaining funds from this year's budget cycle into a Rate Schedule 1 carryover. (See "Proposed RS1 Carryover for 2025 Increases," *NYISO Working Group Meeting Briefs: Oct. 1-2, 2024*.)

CFO Cheryl Hussey explained that paying down NYISO's fixed interest debt would incur significant fees that would "potentially outweigh the benefit of early repayment."

"2024 is the next budget facility year that we could make earlier payments on, and the $7.35 million that we have left is essentially the maximum that we could pay down on the 2024 budget facility," Hussey said. "And then we have about $150,000 in interest savings in 2027."

Hussey said that because the payment would occur in 2025, it would also represent "a little over half a million dollars" in interest savings that were not currently estimated in the budget.

In a separate presentation, Hussey reviewed updates to NYISO's *draft 2025 Corporate Incentive Goals*. Whether the ISO meets the goals affects employee compensation, incentivizing them to be completed, with bonuses for earlier completion. Most of the goals were unchanged from 2024, with some exceptions.

Goal 6B, "Key Project Initiatives," identified eight projects that NYISO believes are critical to complete in 2025:

- investigating whether changes are needed to the capacity market;
- upgrading the hardware that NYISO software runs on;
- developing design specifications and tariff changes needed for the Champlain Hudson Power Express transmission line with Hydro-Quebec;
- developing the software specifications for integrating dynamic reserves;
- developing the software design specifications for FERC Order 2222 compliance;
- finishing the market design for the Winter Reliability Enhancements project;
- migrating off-the-shelf and internally developed applications to the cloud; and
- improving the interconnection study process by upgrading SalesForce software to implement an "interconnection portal" and meeting a FERC order to implement a heat map. ■

Projected Funds Remaining from 2024 Budget Cycle as of 8/31/2024		
Projected Year-End Overcollection	$	4,400,000
Projected Year-End Underspend	$	10,800,000
Projected Total Funds Remaining	$	15,200,000
RS1 Carryover Proposed in Draft 2025 Budget	$	(5,000,000)
Potential Funds Available for Debt Repayment	$	10,200,000

These projections are estimates as of a point in time.
Final budget vs. actual results will differ from these projections.

For Illustrative Purposes Only - Potential Impact of Early Repayment of Outstanding Debt

$10.20M Early Repayment - $2.85M 2023 Budget Facility (BF); $7.35M 2024 Budget Facilitiy (BF)

	Debt Service without Early Repayments		Debt Service with Early Repayments		Estimated Savings from Early Repayments
	2023 BF	2024 BF	2023 BF	2024 BF	
Principal - 2025	9,000,000	12,333,333	11,850,000	19,683,333	
Interest - 2025	458,667	1,341,255	380,567	881,168	538,187
Total	9,458,667	13,674,589	12,230,567	20,564,501	538,187
Principal - 2026	9,000,000	12,333,333	6,150,000	12,333,333	2,850,000
Interest - 2026	134,865	752,242	42,532	290,663	553,911
Total	9,134,865	13,085,575	6,192,532	12,623,997	3,403,911
Principal - 2027	-	12,333,333	-	4,983,333	7,350,000
Interest - 2027	-	234,841	-	80,144	154,696
Total	-	12,568,174	-	5,063,478	7,504,696

NYISO has historically made early repayments on debt that matures in the upcoming budget cycle, reducing the budgeted debt service cost in that year.
The total potential funds remaining from the 2024 budget cycle exceeds the amount that can be paid on the 2023 Budget Facility, which matures in 2026.
Potential early repayment of $2.85M results in 2026 estimated debt service cost savings of $3.4M, including interest.
2024 is the next Budget Facility year that early repayments can be made, which will utilize the projected balance of funds remaining of $7.35M.
Potential early repayment of $7.35M results in 2027 estimated debt service cost savings of $7.5M, including interest.

Insufficient information is available to estimate potential impacts beyond the 2024 Budget Facility year.

Analysis of the potential disposition of funds | *NYISO*

NYISO News

NYISO Management Committee Passes 2024 Reliability Needs Assessment

By Vincent Gabrielle

The NYISO Management Committee on Oct. 31 passed the *draft Reliability Needs Assessment* and recommended that the Board of Directors approve it at its next meeting.

The assessment has identified a reliability need in New York City starting in summer 2033 and "continues to demonstrate a very concerning decline in statewide resources margins such that by 2034 no surplus power would remain without further resource development," according to the executive summary.

The committee passed the assessment *unanimously* via secret, emailed ballot. Some stakeholders abstained from the motion, according to the final writeup of the results.

The New York City need is driven by increased peak demand, limited additional supply and the assumed retirement of the New York Power Authority's small gas plants based on compliance with state climate legislation, NYISO found. Additional generators were also assumed to be unavailable because of the Department of Environmental Conservation's peaker rule.

Consolidated Edison, the transmission owner and local utility, also identified reliability violations in the 138-kV Greenwood transmission load area, but because these reliability violations occur on the non-bulk power transmission facilities, they are not actionable under NYISO's assessment. The ISO wrote that these issues are being brought up so that developers can address both needs holistically.

NYISO was facing a statewide reliability need until it revised some of the incoming large loads, representing about 1,200 MW of cryptocurrency miners and hydrogen plants, to be "flexible." (See *NYISO: Large Load Flexibility Eliminates 2034 Shortfall Concern*.)

Stakeholders raised concerns about this finding similar to those in prior meetings.

"There's no requirement that's imposed on these [crypto miners]. There's no certification from a CEO, as we have in many other instances. There's no filings. There's no commitments. There's nothing in writing at all. It's simply that we don't think they're going to be there" said Kevin Lang, representing New York City. "If Bitcoin goes through the roof, and now it's cost-justified to be running those cryptocurrency mining operations 24/7, what is going to prevent them from doing that? Nothing."

Lang went on to say that he knew this wasn't going to change how the RNA would go, or how the vote would go, but that he wanted to register a large concern. He wasn't the only stakeholder to voice this concern. Others mentioned the potential for cryptocurrency miners to pivot to AI.

"Yes, we are making an assumption here," NYISO's Zach Smith said. "We think it's based on a good amount of information that we've gotten directly from these loads. … Without question this is an assumption we're going to continue to revisit time and time again."

Other Committee Actions

National Grid's Transmission Control Center director, *Matthew Antonio*, was elected vice chair of the committee.

The committee also unanimously passed a motion to ask the board to approve the proposed $1.306/MWh Rate Schedule 1 for the 2025 budget year. The recommendations include a 2025 revenue requirement of $202 million. The committee further recommended that spending underruns and overcollections of RS1 be used to pay down debt or reduce anticipated debt. ■

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PJM News

FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant

Only 3 Commissioners Participate in Order, Which Includes a Dissent from Chair Phillips

By James Downing

FERC on Nov. 1 rejected a proposed amendment to Talen Energy's interconnection service agreement (ISA) with PJM and PPL that would have allowed for the expansion of co-located load at its Susquehanna nuclear plant in Pennsylvania (*ER24-2172*).

The amendment would have let a 300-MW data center owned by Amazon Web Services — already operating behind the fence at the nuclear plant — expand from 300 MW to 480 MW. Controversy around the proposed expansion contributed to FERC hosting a technical conference on co-located load Nov. 1. (See related story, *FERC Dives into Data Center Co-Location Debate at Technical Conference*.)

The order was approved by only Commissioners Mark Christie and Lindsay See: Chair Willie Phillips dissented, while Commissioners David Rosner and Judy Chang did not participate. The majority found that the changes would have led to reliability concerns and novel legal issues. FERC can accept ISAs that do not conform with Order 2003, but parties filing such deals face a high legal burden to justify and explain that the changes are necessary, they said.

Many of the nonconforming provisions of the proposal relied heavily on the generally applicable PJM Guidance Document, which is not part of the RTO's tariff, so FERC has not approved it, the majority said. In a footnote, the commissioners said they made no determination on whether the document is just and reasonable.

"This raises questions regarding whether PJM intends to offer these terms to all similarly situated interconnection customers," FERC said. "We conclude that these provisions demonstrate that PJM has not met its burden to show that these provisions are necessary for any interest unique to the interconnection of the Susquehanna customer facility."

The record indicates other data centers are considering similar deals with other nuclear plants, which shows the provisions from the document do not meet FERC's standards for alternatives to Order 2003.

"This filing leaves multiple important questions unresolved," FERC said. "Nevertheless, given that we have already found that PJM has failed to meet its burden, as described above, we need not further opine on whether PJM has met that burden with regard to the proposed nonconforming provisions herein, or otherwise address the amended ISA."

Phillips argued that because the ISA is the first of its kind, it presents the sort of specific reliability concerns and novel legal issues that justify its acceptance.

"In failing to accept the agreement, we are rejecting protections that the interconnected transmission owner says will enhance reliability while also creating unnecessary roadblocks to an industry that is necessary for our national security," Phillips wrote.

PJM showed that the extra 180 MW of demand would not require any transmission upgrades and the provisions included "several important, reliability-based belts and suspenders," Phillips said. Those provisions would have ensured that no power flowed from the grid to the data center, provided generator shutdown and automatic tripping data to PPL, and notified PJM and PPL of equipment malfunctions.

Phillips also argued that failing to approve the amended deal puts national security at risk, as there is a clear bipartisan consensus that maintaining leadership in artificial intelligence is vital to the national interest.

"Maintaining our nation's leadership in this 'era-defining' technology will require a massive and unprecedented investment in the data centers necessary to develop and operate those AI models," Phillips wrote. "And make no mistake: Access to reliable electricity is the lifeblood of those data centers. I am deeply concerned that in failing to demonstrate regulatory leadership and flexibility, we are putting at risk our country's pole position on this critically important issue. That is simply unacceptable."

Susquehanna nuclear power station | *Talen Energy*

Data center co-location brings up a host of challenging, multifaceted issues that FERC will have to wrestle with, which is why it held the technical conference, Phillips wrote. "But the technical conference casts a far wider net than the matter that is before us today and was never intended to defer judgment on this application, which I believe has thoughtfully and creatively addressed the factors that justify approval of these nonconforming provisions. ...

"We are on the cusp of a new phase in the energy transition, one that is characterized as much by soaring energy demand, due in large part to AI, as it is by rapid changes in the resource mix. Ensuring reliable and affordable supplies of electricity throughout the coming period of increasing demand and changing supply will require pragmatic leadership that facilitates that transition. If we instead throw up roadblocks to that transition, as I am concerned today's order does, we will only deprive our country of the resources needed to ensure our continued economic prosperity and national security."

In a concurrence, Commissioner Christie emphasized the rejection was without prejudice and that Phillips' arguments about national security are unproven by the record before FERC.

He agreed that co-location arrangements present complicated issues that could have huge impacts on reliability and consumer costs, which is why FERC held its technical conference.

"Given these ramifications, the commission truly needs to 'get it right' when it comes to evaluating co-location issues," Christie said. "And make no mistake. Were we to approve this proposal at this time, as the dissent advocates, we would be setting a precedent that would be used to justify identical or similar arrangements in future cases." ■

Why This Matters

The order rejecting the expansion of co-located data center in eastern Pennsylvania shows the competing policy issues before FERC on the issue. It is also a rare case where the chair filed a dissent, and two of the newest commissioners did not participate.

PJM News

FERC Grants ODEC Complaint on $18M Mischarge from FirstEnergy

By James Downing

FERC on Oct. 29 granted a complaint by Old Dominion Electric Cooperative (ODEC) filed against FirstEnergy and PJM alleging the utility overcharged it and asking for $18.6 million in refunds (*EL24-121*).

FirstEnergy's Potomac Edison bills ODEC's load in its territory through PJM based on information the RTO gets from the utility. The complaint alleged that FirstEnergy overcharged ODEC from July 2022 through the end of 2023 by including the load of Front Royal, Va., in the calculations when the co-op does not serve that municipality.

The utilities tried to work out the issue on their own, but FirstEnergy wanted to resettle the entire region because other utilities were undercharged, while ODEC wanted it taken care of bilaterally. FirstEnergy also wanted to pay ODEC only when it got money back from the other entities involved, but by the time the complaint was filed, it had not received any.

ODEC said it did not consent to FirstEnergy imposing the condition that it must resettle with all suppliers prior to providing it with refunds, FERC said.

The complaint asked FERC to find that ODEC was mischarged and that FirstEnergy failed to meet its obligation to timely effect a financial resettlement with PJM, and to direct repayment.

FirstEnergy argued that it was taking the proper steps to fix the mischarges and was working with the rest of the impacted entities to resettle, pursuant to PJM's rules for resettlements. The only reason ODEC did not get any refunds was that it declined to take partial payments as the resettlement of the zone was occurring, the company argued.

ODEC said the rules do not require FirstEnergy to resettle the entire zone before paying back all that it owes the co-op. PJM agreed with this assessment in comments filed on the dispute.

FERC agreed that ODEC was overbilled because of the inclusion of Front Royal's load, which led to it paying more than it owed for energy, capacity and transmission charges.

"FirstEnergy's action in misattributing Front Royal's load to ODEC was a violation of the filed rate," FERC said. "Therefore, we grant the complaint and find that ODEC is entitled to reimbursement of the overcharges. ...

FERC headquarters in D.C. | *© RTO Insider LLC*

"Nothing in the record supports FirstEnergy's assertion that resettlement is required before providing a refund to ODEC. Indeed, PJM states in its answer to FirstEnergy's answer that the PJM tariff and PJM processes do not require that FirstEnergy first resettle the entire wholesale market in its zone before refunding ODEC."

Nothing in PJM's rules applies to the situation in the complaint, so FERC said it was using its discretion to direct FirstEnergy to file a repayment plan to make ODEC whole plus interest within 60 days of the order's issuance. FirstEnergy will have to discuss the plan with ODEC and indicate in that filing whether it has agreed on a plan with the co-op or explain why that did not happen. ■

PJM MRC Briefs

Stakeholders Endorse Issue Charges on ELCC

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee on Oct. 30 endorsed two issue charges sponsored by LS Power addressing the transparency and functionality of PJM's marginal effective load-carrying capability (ELCC) accreditation methodology.

Both were approved by acclamation. (See "LS Power Issue Charges on Accreditation Transparency, Unit-specific Performance," *PJM MRC Briefs: Sept. 25, 2024*.)

LS Power's Tom Hoatson *outlined* several design changes that could be made to the methodology, including reflecting higher potential output in the winter when awarding capacity interconnection rights (CIRs), increasing granularity to allow unit-specific accreditation and recognizing improvements made to generators that may increase their performance.

Hoatson said that because the current approach determines a resource's accreditation by looking at how it performed during emergency conditions, if a generation owner makes improvements to a unit that underperformed during a performance assessment interval, it could be years until its accreditation could be updated, after another emergency occurs.

"You're not able to improve your accreditation unless you have another Winter Storm Elliott event," Hoatson said, referring to the December 2022 winter storm.

There is also an incongruence between the risk modeling approach PJM implemented following the Critical Issue Fast Path process last year, which concentrated risk in the winter, and the use of summer ratings to determine the expected output for some generators, Hoatson said. While the issue charge is not seeking a sub-annual market design, he said there is potential to better align risk modeling and accreditation.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said there are circumstances beyond a generation owner's control that result in a resource being labeled as underperforming and there should be a mechanism to allow for steps to be taken to improve accreditation following an event.

"This is a must-have for many of us, and I think this will help PJM retain a lot of resources in the future," he said.

The issue charge aims to file a proposal with FERC in the first quarter of 2025 to be implemented to whichever auction may be held in December of that year, Hoatson said, noting that PJM has requested a delay of the 2026/27 Base Residual Auction (BRA) and several to follow.

PJM's Adam Keech said that for any changes to be implementable for an auction conducted in December 2025, a filing would need to be submitted in March or April. While that timeline is doable, he said it's important that stakeholders keep the tight turnaround in mind.

"There's not much time to get changes in for that auction; we are happy to move through this in an expedited fashion," he said.

The second *issue charge* seeks to add transparency to the ELCC process by encouraging more data sharing with generation owners, publishing assumptions underlying class ratings and establishing a date certain for the posting of planning parameters associated with ELCC assumptions. It also envisions a model that stakeholders could use to estimate accreditation of resources they own or representative stand-ins, as well as the ability to modify assumptions to create accreditation sensitivities.

"Given the large adjustments recently announced to near-term load growth expectations and continued retirement declarations, it has become increasingly important to determine whether and how the accreditation approach as currently implemented will incent needed investment in new and existing resources to maintain resource adequacy," the issue charge states.

Vote on Issue Charge to Establish SATA Rules Deferred

Stakeholders deferred action on an *issue charge* brought by PJM to explore rules to govern battery storage as a transmission asset (SATA) after several argued that members may be inundated with other issues over the coming months. (See "PJM Proposes Reopening Discussion of Storage as a Transmission Asset," *PJM MRC Briefs: Sept. 25, 2024*.)

The motion made by Adrien Ford, Constellation Energy director of wholesale market development, delays action on the issue charge any earlier than February and requires completion of education on the subject at the Operating Committee as well. Ford said stakeholders are being asked to consider numerous issue charges at once and it's important that the issue charge is written correctly to avoid having to go back to the drawing board, which requires education before moving forward.

Why This Matters

The Independent Market Monitor and several stakeholders have pointed to PJM's marginal ELCC accreditation paradigm and risk modeling approach as factoring into a significant increase in capacity prices in the 2025/26 Base Residual Auction.

Delaying action was broached by Erik Heinle of Vistra, who noted that stakeholders are also juggling PJM's Reliability Resource Initiative — which would create a special application window for high-capacity factor resources to enter the second transitional interconnection queue — and a possible Federal Power Act Section 205 filing to revise aspects of the capacity market.

"When I look around at the most burning issues right now, we're at a place where we're trying to put the fires out ... and I don't know that this fits in, so I'm wondering if it makes sense to push this back six months," he said.

PJM Director of Stakeholder Affairs Dave Anders said the issue charge sought to delegate the work to the OC in an effort to avoid adding to the workload of other committees already working on other major topics. Heinle responded that members tend to have the same staff working on issues across PJM's working groups, and, regardless of the venue, another issue charge would add to their responsibilities.

The RTO also opted to avoid discussion of dual use for storage assets — allowing them to simultaneously act as both transmission and market resources — because of the extensive stakeholder engagement that may entail.

"Dealing with that dual-use aspect will probably be more time consuming, and we would like to move forward with the operational aspect of it," Anders said.

Independent Market Monitor Joe Bowring stated that "there is no logical difference between storage as a transmission asset and a generating unit as a transmission asset. Storage is a competitive market resource in PJM. The MMU opposes the inclusion of competitive market resources in transmission

PJM News

owner rate base because it creates a slippery slope towards rate base rate of return regulation which some are already promoting more broadly."

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said advocates broadly support expanding implementation of storage, and while there are some who are frustrated that the issue charge precluded dual use, they support it. He said some advocates may seek further changes to the rules for market-oriented storage resources through the Public Interest and Environmental Organization User Group.

Calpine's David "Scarp" Scarpignato said he is concerned about the prospect of creating a class of regulated transmission assets that could be dispatched to address transmission constraints and the impact that could have on PJM's markets. He questioned how it could be determined which type of resource would be dispatched under various circumstances.

"You can't have somewhat regulated resources being paid for and then expect competitive resources to jump in or participate," he said.

CIR Transfer Proposal Discussed

The MRC discussed a *proposal* to create an expedited process for studying resource interconnection requests that would be using CIRs from deactivating generators.

A page turn of draft tariff language is scheduled to be conducted during a special session of the MRC on Nov. 14. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

The package is the continuation of the stakeholder coalition endorsed by the Planning Committee on Oct. 8, which won out over proposals from PJM and the Monitor.

The defining feature relative to the PJM approach is permitting any resource type to receive CIRs and take advantage of the expedited process; the RTO would have categorically excluded storage resources and applied a material adverse impact standard, which opponents argued would effectively limit it to resources of the same fuel type. The process would be limited to projects sited at the same substation and at same voltage as the retiring unit.

Donnie Bielak, PJM director of interconnection planning, said the RTO's primary concerns with the coalition package were addressed by the inclusion of a wider set of studies that would be conducted on the impacts a project may have on the grid. Projects' significant network upgrades would be bounced to the standard interconnection queue, while those

Dave Anders, PJM | © *RTO Insider LLC*

with minor upgrades or none at all would be permitted to proceed in the parallel queue.

The studies would be conducted on the latest phase 2 or 3 model in the wider queue, which Bielak said would result in minimal disruption to the processing timeline for other projects.

Bowring said allowing bilateral trading of CIRs would create market power for retiring resource owners and could slow resource replacement by allowing those rights to be held for a year before they are transferred. He added that there would be no consideration of the reliability value of the replacement resource nor a requirement that it offer into the capacity market. The Monitor's proposal would have allowed resources to move to the front of the queue if they resolved a reliability issue and committed to a specific in-service date and being a capacity resource.

The Monitor's proposal would have created a PJM-administered process where generation owners could propose new projects to mitigate any transmission violations prompted by a resource deactivation. Any CIRs not transferred through that process would be made available to others in the interconnection queue.

Elevate Renewables' Tonja Wicks said this would not be a process where generation owners are handing CIRs over to the highest bidders. Instead, they would be intending to replace their resources with new units at the same location to bring new assets online as quickly as possible.

PJM Revives Proposal to Sunset Clean Attribute Procurement STF

Clean Attribute Procurement Senior Task Force (CAPSTF) facilitator Scott Baker, PJM business solutions engineer, *presented* a proposal to sunset the group as states gravitate toward a clean attribute trading program outside of FERC jurisdiction.

PJM had broached terminating the group during the MRC's October 2023 meeting, stating that the task force had run its course when its three proposals were rejected without a clear path forward. PJM dropped its recommendation to sunset at the next meeting, and the committee voted against a motion to close the task force. (See "Vote to Close Clean Attribute Group Fails," *PJM MRC/MC Briefs: Nov. 15, 2023*.)

The task force was formed in April 2022 following MRC approval of an *issue charge* to consider changes to PJM market design to facilitate the creation of a regional, voluntary market for trading clean resource attributes. The discussions yielded three packages, all of which failed to receive majority support in a poll conducted in May 2023. Following that poll, several states formed the Forward Energy Attribute Market (FEAM) Working Group to discuss possible market design and jurisdictional issues. Though the working group was not affiliated with PJM or the Organization of PJM States Inc. (OPSI), its meeting documents can be found on the latter's website.

According to a legal and jurisdictional analysis consensus *report* presented in May 2024, both state-defined renewable energy credits and clean energy attribute credits could be sourced from any qualifying resource and traded among voluntary buyers, such as companies and municipalities with clean energy targets.

The report states that the credits would not be bundled with the sale of energy and therefore would not fall under FERC's jurisdiction. It would also not require that states recognize each other's definitions for qualifying credits, nor would it transfer one state's authority to another — thereby not requiring congressional approval to establish. Instead, it might take the form of a designated contracts market subject to the U.S. Commodity Futures Trading Commission.

1st Read on 3rd Phase of Hybrid Resource Rules

PJM's Maria Belenky *presented* a package of governing document revisions to expand the RTO's rules for hybrid resources to include non-inverter-based generation paired with storage.

The Market Implementation Committee endorsed the revisions Oct. 9. (See "Third Phase of Market Rules for Hybrid Resources Endorsed," *PJM MIC Briefs: Oct. 9, 2024*.)

The hybrid rules would not be applicable to combinations of non-inverter and intermittent generation units, which would be classified as co-located resources. Belenky said PJM is not foreclosing a future pathway for an additional

PJM News

stakeholder discussion on creating a hybrid model for such resources. The rules for non-inverter-based hybrid participation in the energy and ancillary services markets would be based on the Energy Storage Resource Participation Model detailed in Manual 11.

The revisions would also specify that a hybrid with any component that is subject to the requirement that resources offer into the capacity market would also be subject to the must-offer rule. Hybrids with no component subject to the rule would not be mandated to participate in the market.

They would also make clarifications to the existing hybrid rules and align language across the governing documents and manuals. That includes defining how generation owners may determine whether the storage component of a hybrid would be offered as a closed loop, incapable of charging from the grid, or an open loop. Belenky said that if the battery is physically or contractually able to charge from the grid, it must be offered as open loop, but there may be circumstances in which the resource owner may wish to operationally limit it to closed-loop usage.

The revisions would allow generation owners to change loop classification according to the existing technology change rules. A capacity resource is permitted to change its ELCC class once every five years with a request submitted by Aug. 1 of the year prior to the relevant BRA. Energy-only resources can make such a change every year with a request made by May 30 of the previous calendar year.

Other MRC Business

PJM's Michele Greening *presented* a first read on tariff and Reliability Assurance Agreement revisions drafted by the Governing Document Enhancement and Clarification Subcommittee. The changes include removing sunset terms and obsolete references, correcting drafting errors and clarifying instructions.

PJM presented revisions to manuals 3 and 10 drafted through the documents' periodic review. The *changes* to Manual 3: Transmission Operations would update links and references, clarify the process for revising timely transmission outages, and reflect existing practices on facility ratings. The Manual 10: Prescheduling Operations *revisions* would clarify how outages for inverter-based resources are reported in eDART, specify that work on forced outages must be completed before planned outages can start and correct an exhibit showing the time the day-ahead market closes.

PJM's Suzanne Coyne gave a first read on *revisions* to Manual 28: Operating Agreement Accounting to expand the lost opportunity cost (LOC) formula to hybrid, storage and solar resources. The formula currently only applies to wind resources.

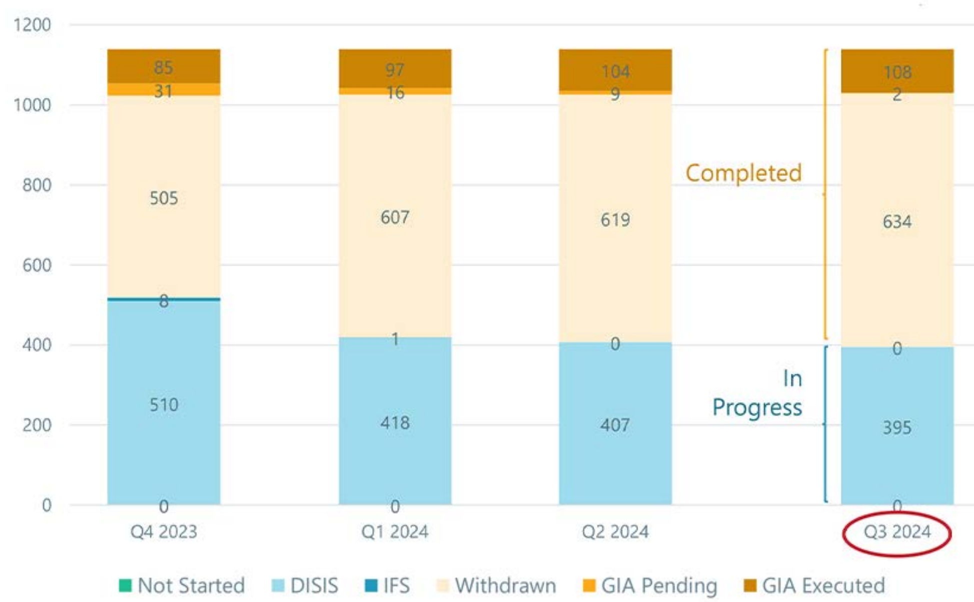
The committee endorsed tariff *revisions* to make PJM's creditworthiness review of bilateral capacity transactions more proactive. The revisions would require that auction-specific and locational unforced capacity transactions be submitted to PJM in advance for credit review and advance approval. PJM would be expected to approve transactions submitted prior by 1 p.m. by the end of the next business day; submissions made after 1 p.m. would be complete within two days. The credit risk of all parties to the transaction and its potential market impact would be considered in the review. The proposal was added to the Members Committee's consent agenda by acclamation following the MRC meeting. ■

— Devin Leith-Yessian

SPP News

FERC Grants SPP Waiver for GI Queue Backlog

FERC has approved SPP's waiver request to delay processing its 2024 generator interconnection study cluster as the RTO works to clear a backlog of GI requests that date back to 2018.



SPP's progress in clearing its backlog of GI requests. | *SPP*

The commission said Oct. 30 that the waiver request met its four criteria for approval in that SPP acted in good faith, the request is limited in scope, it remedies a concrete problem, and granting the waiver will not have undesirable effects, such as harm to third parties (*ER24-2860*).

The waiver allows SPP to defer starting the definitive interconnection system impact study (DISIS) for the 2024 cluster until completing the first planned restudy of the DISIS-2023-001 cluster; extending the close of the 2024 DISIS queue cluster window from Oct. 31 to March 1, 2025; and opening the 2025 DISIS window until April 1, 2026, or the completion of the second decision point for the 2024 DISIS cluster.

The grid operator told FERC that waiving the tariff provisions will enable it to focus its "limited resources" on processing the unprecedented number of interconnection requests already in the queue. It also said the waiver won't delay executing GI agreements for pending or future clusters and will prevent lower-queued and future interconnection customers from expending time and resources considering study- and interconnection-cost-related information that could become moot due to restudies of higher-queued clusters.

SPP began tackling the backlog in 2022 with the 2018 cluster. The queue contained 1,139 active requests for 221 GW of capacity at the time; it now has 395 active requests for 82 GW of capacity. The RTO has executed 48 new GIAs for 7.75 GW of capacity during the backlog work. (See "SPP Modifies GI Backlog Process," *SPP Markets & Operations Policy Committee Briefs: Oct. 15-16, 2024*.) ■

— Tom Kleckner

NV Energy Explains EDAM Choice

By Elaine Goodman

NV Energy's decision to join CAISO's Extended Day-Ahead Market (EDAM) rather than SPP's Markets+ was based partly on concerns that participation in the latter would "lead to substantial expenditures with limited results," a representative of the Nevada utility said.

In contrast, NV Energy has "high confidence" that EDAM's first-movers will stand up the market and it will have the connectivity to produce customer benefits, according to David Rubin, the utility's federal energy policy director.

Rubin was speaking Oct. 28 at a meeting of Nevada's Regional Transmission Coordination Task Force to give an update on the utility's day-ahead market activities.

The *RTCTF* was created by 2021's *Senate Bill 448*, which also requires transmission providers in the state to join an RTO by Jan. 1, 2030.

In May, NV Energy confirmed in public statements and regulatory filings that it intends to ask the Public Utilities Commission of Nevada (PUCN) for authorization to join EDAM. (See *NV Energy Confirms Intent to Join CAISO's EDAM*.)

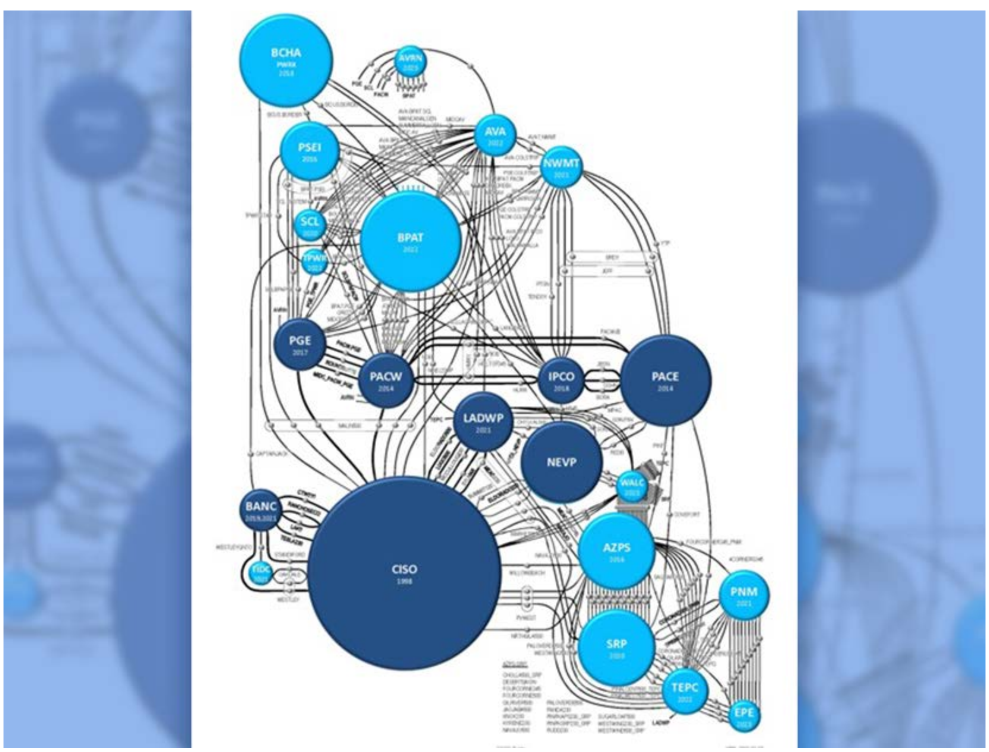
The decision is viewed as an important victory for EDAM because of NV Energy's central location in CAISO's Western Energy Imbalance Market (WEIM).

Rubin showed a diagram with dark blue circles depicting balancing areas expected to participate in EDAM, including PacifiCorp, Portland General Electric, the Los Angeles Department of Water and Power, Idaho Power and the Balancing Authority of Northern California.

Expanding that footprint to include other WEIM entities would provide even greater benefits to participants, Rubin said. But even if the footprint doesn't widen from what's now expected, "the dark blue footprint with its connectivity should produce extensive benefits," he said.

A Brattle Group study for NV Energy showed that footprint contains 46% of WECC's load, 80% of the solar generation, 70% of the storage capacity and much of the wind power, Rubin said.

It projected that the utility's annual benefits with EDAM would range from $62 million to $149 million, depending on the market footprint. In contrast, results from Markets+ participation would range from a $17 million annual loss to a $16 million gain. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)



An NV Energy official said the company would gain "extensive benefits" from joining CAISO's EDAM, even if the footprint includes only the balancing areas depicted by the dark blue circles in this diagram. | *CAISO*

Stakeholder Role

Another factor NV Energy weighed in its day-ahead market decision was the role of stakeholder participation.

In EDAM, CAISO staff work to balance positions expressed by stakeholders, Rubin said, while Markets+ employs a stakeholder-led process in which staff are more passive.

Rubin said that when NV Energy participated in the SPP process, Northwest entities tended to vote as a block while Southwest entities often varied in their opinions. As a result, NV Energy was frequently outvoted, he said.

In CAISO's process for EDAM, "staff involvement helps protect minority interests that can get overruled by SPP's deterministic voting structure," Rubin said.

CAISO's process also makes greater use of written comments, he said, which allow stakeholders to more fully explain their positions. And the written comments can be reviewed by those who weren't able to attend a meeting.

Building on WEIM Benefits

By joining EDAM, NV Energy can build on the substantial benefits it has earned through participating in WEIM since December 2015.

CAISO *announced* Oct. 28 that overall WEIM benefits have grown to $6.25 billion; NV Energy has seen cumulative benefits of $589 million through the third quarter of 2024.

Rubin said NV Energy's WEIM benefits have grown appreciably as the company has gained experience in the market and its footprint has expanded. Those benefits have helped bolster NV Energy's confidence in EDAM.

In contrast, "we have less confidence in Markets+, even if entities spend the $150 million necessary to build out the SPP design," he said.

NV Energy expects to file a request for authorization to join EDAM with the PUCN in the second quarter of 2025. That timing will give the company time to complete its integrated resource plan filed with the commission and see how the footprints evolve for the two competing day-ahead markets.

There also may be reactions by then to PacifiCorp's open access transmission tariff for its participation in EDAM, expected to be filed with FERC in November, as well as a potential PGE filing in January. ■

SPP News

SPP, AECI Release Draft Joint Study to Stakeholders

By Tom Kleckner

SPP and Associated Electric Cooperative Inc. (AECI) have given stakeholders until Nov. 15 to review a *draft study* that has identified potential joint transmission projects mutually beneficial to the grid operators.

The 2024 Joint and Coordinated System Planning (JCSP) study found several projects of interest to SPP and AECI. Several of the projects also are in SPP's 2024 Integrated Transmission Plan (ITP) portfolio that recently was approved by the RTO's board. (See related story *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

"Some of these projects may look very familiar," SPP's Clint Savoy, manager of interregional strategy and engagement, said during a Nov. 1 meeting of the AECI-SPP Interregional Planning Stakeholder Advisory Committee. "We tried to cast a wide net with this study."

Savoy said it was unlikely any of the projects in the report would replace any from the ITP, but that staff were looking for projects with "even the smallest potential for cost sharing."

The 2024 JCSP study horizon included modeling the transmission system for the next 10 years, which will provide lead time so appropriate approvals may be obtained, and project owners can begin work promptly.

The grid operators plan to review the feedback and issue a final report. They will continue to filter through the list of projects and determine which ones, if any, meet the qualifications for sharing costs.

The AECI-SPP joint operating agreement requires staff to conduct a JCSP study every other year to ensure the reliable, efficient, effective planning and operation of the transmission system along the grid operators' seam.

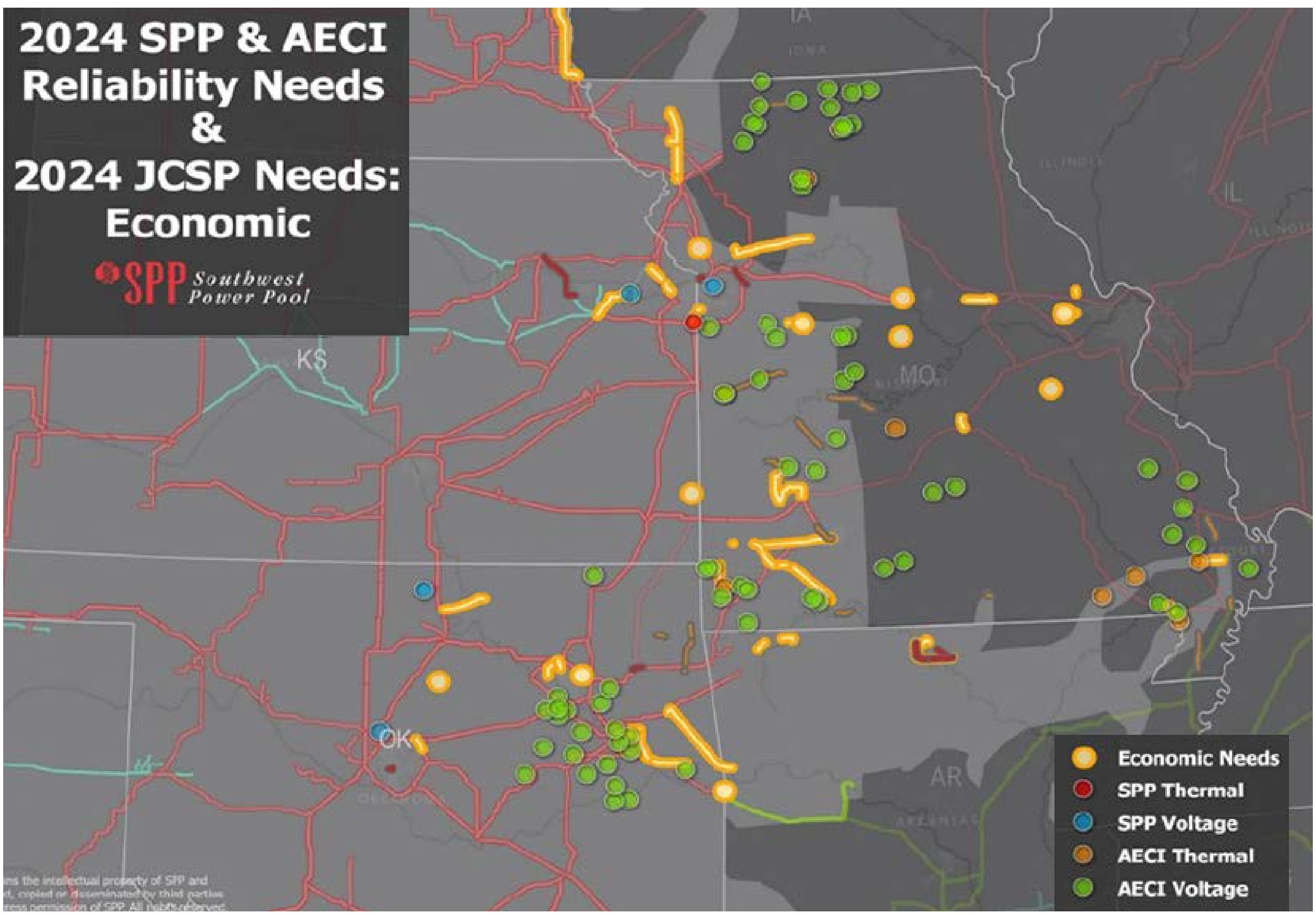
MMU Releases Summer Report

SPP's Marketing Monitoring Unit has released its quarterly *State of the Market Report* for the 2024 summer. The report, covering June through August, indicates day-ahead and real-time prices dropped during the season, driven predominantly by lower gas prices.

Day-ahead prices decreased 17%, from $35/MWh in 2023 to $29/MWh in 2024. Real-time prices also fell 17%, from an average of $32/MWh in 2023 to $27/MWh in 2024.

The system's average hourly load was 3% above 2023, while the peak hourly load was down 3% compared to 2023.

Wind resources accounted for 30% of SPP's total generation during the summer. A year ago, wind was 24% of the generation mix. Coal generation fell from 34 to 28%. ■



Identified reliability and economic needs by SPP and AECI. | *SPP*

SPP News

SPP Board Approves $7.65B ITP, Delays Contentious Issue

Stakeholders, Staff at Odds Over Need Dates for 2 Winter Weather Projects

By Tom Kleckner

LITTLE ROCK, Ark. — SPP's Board of Directors has approved the grid operator's "historic" $7.65 billion package of transmission projects but delayed a decision on a need date for two of the 89 projects after stakeholders pushed back on staff's staging recommendations.

Stakeholders argued that the two projects in question be staged as soon as possible, with two working groups voting to classify winter-weather projects as persistent operational solutions in approving winter-weather need dates.

Staff recommended using analysis and staging methodology consistent with the tariff and transmission planning manual. They added a Year 2 winter-storm model late in the planning process to calculate December 2028 need dates for the two projects.

Following more than three hours of discussion over two days among themselves and with staff and stakeholders, the directors on Oct. 29 took a Solomonic approach by agreeing to delay a decision on the projects' need dates to no later than their Dec. 9 board meeting. They rejected the original proposal to set the deadline before their February meeting.

Until then, stakeholders will continue the staging discussion in the working groups. The Markets and Operations Policy Committee (MOPC), which endorsed the 2024 Integrated Transmission Plan (ITP) with 95% approval, also plans to hold a conference call before the December board meeting.

Evergy's Derek Brown, chair of the Transmission Working Group, said the disconnect between staff and stakeholders emerged over the projects' need dates. That led stakeholders to endorse the larger projects that make up much of the transmission package's size.

"We have the models and the inputs, and we spent months building those to support the justification for when these projects are needed ... and that got us to the five-year model," he told directors and stakeholders. "We have projects coming in service. We have load growing. We have generation retiring. We need to look out at least five years to be able to right-size the solutions. So, when we looked at that five-year model, surprise! Things get worse.

Evergy's Derek Brown (right), with SPP's Casey Cathey, explains stakeholders' view on staging ITP projects. | © RTO Insider LLC

"At least from a transmission planning standpoint, all those projects are part of the packaged solution, so they should all have need dates as soon as possible. If the system had shown things get better in Year 5 and we don't need all of those projects, we wouldn't be recommending them today."

"Nothing's ever easy, and it probably shouldn't be with this large of a portfolio," said SPP's Casey Cathey, vice president of engineering. He noted that the Integrated Transmission Planning (ITP) manual does not have processes for creating historical winter weather models or to determine a need date for projects from past events.

Because staff's winter-weather models were based on previous extreme conditions during February 2021 and December 2022, stakeholders voted to stage projects as persistent operational projects.

"It became apparent about two months ago that not only is the winter-weather staging not outlined in the manual ... but it's not easily defendable when you look at the governing language," Cathey said, pointing to multiple sections in the manual and tariff. "If you map all of that, you have to use a Year 2 model to interpolate and determine what the staging needs are."

The two projects in question are the Tobias-Elm Creek 345-kV transmission line on the western side of SPP's footprint, an 85-mile segment valued at $887.46 million, and the 154-mile, $484.09 million Buffalo Gap-Delaware 345-kV line from Kansas into Southwest Missouri. The projects were identified in the Winter Storm Uri and Elliott models, respectively.

The first project is expected to increase transfer capability from SPP North to SPP South and decrease the chances for load shed. The second brings a new EHV source into Missouri to support system voltage and transfers from SPP.

Three other projects related to the winter storm projects were given need dates of December 2025 or upon being issued a notification to construct.

The *2024 ITP portfolio* is SPP's largest in both size and value in its 20 years as a transmission planning coordinator, it said. The plan includes 89 transmission projects, representing 2,333 miles of new transmission and 495 miles of rebuilds — including 1,900 miles of the RTO's first 765-kV lines — to address increasing load growth and changes in the region's generating fleet. SPP expects the portfolio's benefits to exceed costs by a ratio of at least 8-to-1.

Despite the package's cost, MOPC approved the ITP with 95% approval and little discussion of staging. The issue has since bubbled up in the working groups. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.)

The Members Committee approved the board's motion to delay the staging date for the two projects in their advisory vote, 17-5 with one abstention, with renewable interests providing the opposed votes. They also cast four votes against the portfolio's approval, expressing concern over the lack of transparency into delayed projects. ■

Southeast news from our other channels

SE Renewable Energy Conference Hears Blunt Talk on Trump

NetZero Insider

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

SPP Board/Regional State Committee Briefs

Directors Approve 2025 Budgets, Net Revenue Requirement

LITTLE ROCK, Ark. — SPP's Board of Directors approved the RTO's 2025 operating and capital budgets and its net revenue requirement (NRR) on Oct. 29 following a unanimous endorsement by the Members Committee.

The budget includes $296.3 million in expenses, a 7.6% increase ($21 million) from this year's budget. SPP's headcount has exceeded 650 to meet an increasing workload, thanks to Western Interconnection market services and FERC orders 881 and 841.

The NRR is budgeted for $204 million, a 6.2% increase from the current $192.1 million. Staffing and related expenses account for about two-thirds of the NRR; SPP's tariff limits the NRR to a ratio of estimated annual transmission usage, capped at 46.5 cents/MWh.

The capital budget was initially set around $35 million, more than doubling the 2024 allocation of $17 million. However, SPP identified projects that could be deferred or eliminated to reduce that spending to $22.1 million.

Independent Director Stuart Solomon, who chairs the Finance Committee, commended staff and the committee for putting together "one of the best budget documents" he has ever seen.

"I think you'll agree with me that they met the goal of balancing necessary expenses with affordability and member value," he told stakeholders during the board's October meeting.

"We started way back in February of this year with a particular goal in mind: to try to bring greater alignment between SPP strategy, our operating plan, the identification of the necessary resources to effectuate that operating plan and, ultimately, the delivery of the budget," CFO David Kelley said.

Kelley and Solomon both pointed to the NRR's run rate, or the cost to operate the RTO year to year, as a metric to watch. The NRR's budgeted run rate next year is a 4.5% increase from 2024.

"I think that's impressive, given the increasing costs that all of us are experiencing and the amount of new work and requirements that SPP and SPP staff is dealing with," Solomon said.

SPP CEO Barbara Sugg, with Board Chair John Cupparo, addresses the board and Members Committee. | © RTO Insider LLC

Members expressed support for the budget but cautioned SPP about not forgetting who ends up paying for the budget increase.

"We appreciate the additional focus on controlling costs in this particular budget," Oklahoma Gas & Electric's Emily Shuart said. "That said, I do want to be transparent about our expectations going forward, and that we don't find the 4.5% year-over-year increases sustainable or representative of the budget constraints that members like OG&E are facing. This budget is just one cost stream associated with membership that our customers end up bearing."

"We understand that these are real dollars that we're asking you all to spend and they show up on ratepayer bills at the end of the day," Kelley said. "I can assure you that everyone throughout the SPP organization understands that, and we understand that we have to keep costs as low as reasonably possible."

Dec. 16 Key Date for Markets+

SPP's Antoine Lucas, vice president of markets, told stakeholders that staff are targeting Dec. 16 to begin building out its Markets+ offering in the Western Interconnection.

The RTO hopes its response to FERC's deficiency letter will have met with the commission's approval by then and that it has also executed Phase 2 funding agreements with interested market participants. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.)

"With those two things, we have everything that we need to move forward with the actual development of the market and the execution of Phase 2," Lucas said Oct. 28 during staff's quarterly stakeholder briefings, alluding to the market's development and delivery.

He said staff have been working "extensively" with Western stakeholders in developing the market protocols. The Markets+ Participants Executive Committee will vote on the new protocol language during its Nov. 12-13 meeting in Portland, Ore.

SPP has also filed its *response* to FERC's deficiency letter for the *Western expansion* of its RTO. It submitted the tariff in June as it seeks to become the first grid operator with markets in both the Western and Eastern Interconnections. (See *FERC Issues Deficiency Letter for SPP's RTO West Tariff*.)

Summer Ops Report

Despite summer weather that extended into October, SPP's Bruce Rew, senior vice president of operations, said demand was high but did not reach record levels. Demand peaked at

SPP News

54.39 GW in July, short of 2023's record peak of 56.18 GW.

SPP registered 18 days with loads over 50 GW, one less than 2023 but the third straight year with double-figure 50-GW days. There were only 11 50-GW days total in 2019-2021.

The RTO issued 24 resource alerts or conservative operations calls this year, down from 40 the year before. It did issue a Level 1 energy emergency alert for two and a half hours Aug. 26, when elevated temperatures and low wind generation resulted in high net load obligations that reached August 2023 levels. Forced outages approached 9 GW, near all-time highs. (See *SPP Issues EEA 1 as Heat Scorches Midwest*.)

RSC to Engage on Order 1920

The Regional State Committee agreed during its Oct. 28 meeting to collaborate on a cost-allocation process as part of *FERC Order 1920*'s requirement for a six-month engagement period with relevant state entities or commissions.

The order requires transmission providers to use a 20-year horizon in planning their long-term regional needs.

SPP's engagement period began Oct. 28 and will end May 5, when the RSC meets in Omaha, Neb. The grid operator has to make a compliance filing next August.

"The six-month engagement period ... is requiring that we offer to provide a forum for negotiation of a cost-allocation methodology and/or the state agreement process," SPP attorney Tessie Kentner said. "The order does specify that if there is an existing mechanism in place, such as the RSC, that can also be used."

Outgoing RSC President John Tuma, a member of the Minnesota Public Utilities Commission, said SPP's willingness to work with the states is why Minnesota joined the committee.

"You have created a culture within SPP [in which] states are equal partners in this effort and working together to accomplish good things within the RTO structure," Tuma told SPP CEO Barbara Sugg. "Minnesota values that. We saw the value of RTOs to reduce the cost of energy and providing stable regional grid for us, and so that's why we joined."

The RSC also elected its officers for 2025:

- President: Pat O'Connell, New Mexico Public Regulation Commission
- Vice president: Chuck Hutchison, Nebraska Power Review Board

Incoming RSC President Pat O'Connell, New Mexico Public Regulation Commission | © *RTO Insider LLC*

- Secretary/treasurer: Kim David, Oklahoma Corporation Commission

"I've been involved in RSC for a couple years. What I've found is it's always an opportunity for improvement and there's always a new challenge, or new challenges, every year," O'Connell said. "I'm looking forward to the challenge. Thanks to all for the trust in me and the situation we're in now, because it looks to be a very easy job."

Annual Membership Elections

During SPP's annual meeting of members, the membership re-elected board Chair John Cupparo and independent Directors Susan Certoma and Ben Trowbridge to three-year board terms that begin in January.

Certoma will be serving her third term, and Cupparo and Trowbridge their second.

The membership also elected eight utility representatives to three-year terms on the 23-person Members Committee, where they will serve as proxies for their sectors:

- Investor-owned utility sector: Tim Wilson (Liberty Utilities) and Denise Buffington (Evergy)
- Cooperative sector: Zac Perkins (Tri-County Electric Cooperative) and Mike Wise (Golden Spread Electric Cooperative)
- State agency sector: Robert Pick (Nebraska Public Power District)
- Independent power producer/marketer sector: Kevin Smith (Tenaska Power Services) and Brett White (Pine Gate Renewables)
- Public interest/alternative power sector: Christy Walsh (Natural Resources Defense Council)

Most of those elected are incumbents. Pick and Buffington are new, but Buffington is serving the remainder of former co-worker Kayla Messamore's term before beginning her own Jan. 1. White is filling the remainder of former member Rob Janssen's term, which ends after 2025.

The membership also approved a bylaw change brought forward by the Corporate Governance Committee that will revise the selection of Members Committee representatives. With FERC's approval, sector members will be able to nominate committee representatives, who will then be submitted to the CGC for nomination to the membership.

The CGC said that sectors selecting their representatives on the committee would best represent the interests of each sector and would encourage greater collaboration and engagement between the sectors.

More Time to Cure RAR Obligations

The board approved a revision request (*RR632*), previously endorsed by the RSC and Markets and Operations Policy Committee, that gives load-responsible entities several more weeks to address deficiencies in meeting their resource adequacy requirement.

LREs would have from March 15 to May 15 (an additional 30 days) to cure summer season deficiencies and from Sept. 15 to Nov. 15 (15 extra days) to resolve winter season deficiencies.

The board's consent agenda included SPP's annual *violation relaxation limit analysis*; converting the Reliability Compliance Advisory Group to a user forum, removing the formal requirements of a chair and recorded minutes; member nominations to the Finance, Strategic Planning and Human Resources committees; and revising the SPC to mirror the sector-based composition of the Members Committee.

It also included another RR (*RR649*) that aims to add value to the network resource interconnection service (NRIS) product by creating an expedited process for designating new network and designated resources outside of the aggregate transmission service study process. It also revises the generator interconnection study process for new NRIS requests, defines deliverability areas and allows existing resources that meet eligibility requirements to use the expedited process. ■

— Tom Kleckner

Company News

Xcel Welcomes Load Growth from Data Centers

By Tom Kleckner

Xcel Energy says data center load will accelerate its ability to develop both transmission and generation. | *Ascenty*

Xcel Energy CEO Bob Frenzel welcomes the coming wave of data centers, despite the increased demand they will place on the grid.

Frenzel told financial analysts during the company's third-quarter earnings conference call Oct. 31 that Xcel has nearly 9 GW of "opportunities" before 2030 in the customer pipeline. He said the company expects about a quarter of those projects will secure contracts during the next five years.

"The scale of this pipeline gives us the ability to thoughtfully negotiate agreements that deliver the energy and capacity needed to important new customers in the region [and ensure] that new data center load that's brought onto our system benefits all customers," Frenzel said. "It drives load growth to our increasingly decarbonized energy system, generates economic growth in vitality in our communities and delivers on the national imperative to support a domestic data center industry."

As the large loads come looking for transmission and generation service, Frenzel said, they highlight a different need.

"We, as a country, [and] we, as an industry, need to be accelerating our ability to develop both transmission and generation to serve the load that we think is going to come. It's meaningful load. If you can provide it across the entire country, it seems manageable as you get into very specific load pockets; it comes with a lot of need and a lot of speed that's needed," he said.

"We're starting to see this energy transition we've been talking about and working on for the past five years really start to accelerate. We're proactively removing our coal plants from the system and replacing them with cleaner and, in some cases, lower-cost generation resources," Frenzel added. "I think that is an opportunity for us to mitigate cost increases across the entire country as we transition both our transmission and generation footprint for the next generation."

The Minneapolis-based company *reported* third-quarter earnings of $682 million ($1.21/share), compared with $656 million ($1.19/share) in the same period in 2023.

Xcel also introduced its new five-year, $45 billion investment plan, with a focus on four key areas, Frenzel said: clean energy, customer electrification, new load growth, and safety and reliability.

The company's share price was up nearly 6% on Oct. 31 at $66.81, a $3.76 gain from its previous close. ■

Company News

Constellation Pushes Ahead on Co-located Data Centers

Nuclear Operator Plays Down Significance of FERC Ruling in Talen-Amazon Case

By John Cropley

Constellation Energy remains bullish on data centers co-located with nuclear power plants despite FERC rejecting terms for the expansion of one such agreement in a high-profile ruling.

Data centers are critical to the economy and national security of the United States, and co-location is among the best ways to get them built quickly, CEO Joe Dominguez said Nov. 4 during a *call with financial analysts*.

The nation's largest nuclear power plant operator is working to restart the reactor it owns at the former Three Mile Island station to help meet the projected rise in power demand.

Constellation already has signed a power purchase agreement with Microsoft for the zero-carbon output from the reactor, which has been renamed the Crane Clean Energy Center.

Dominguez noted the company could boost its nuclear generation an additional 1 GW or more through uprating the facilities and said customers have expressed interest in contracting for that output.

The Nov. 4 conference call was intended to provide details and take questions on *Constellation's third-quarter financials*, but Dominguez immediately launched into his thoughts on FERC rejecting terms of the deal to expand Amazon's data center co-located at Talen's nuclear plant (*ER24-2172)* after a Nov. 1 technical conference. (See related stories *FERC Dives into Data Center Co-location Debate at Technical Conference* and *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

Nearly 10 minutes into the call, Dominguez switched to Constellation's quarterly financials, which once again were strong: GAAP net income was $3.82 per share and adjusted operating earnings were $2.74 per share, up from $2.26 and $2.13 respectively in the third quarter of 2023.

The company again bumped its 2024 earnings projection higher and said it would grow its earnings per share by at least 13% through 2030.

Despite this, Constellation Energy stock closed 12.5% lower in heavy trading Nov. 4, a plunge widely presented as fallout from the FERC ruling.

Dominguez downplayed the significance of the ruling in his opening remarks and again during the Q&A with financial analysts.

It was a very narrow decision on the proposed interconnection service agreement, he noted.

"In Constellation's view, the 2-1 ruling rejecting Talen's ISA by a fraction of the commission is not the final word from FERC on co-location," Dominguez said. "We believe that all of the commissioners, including the two who recused themselves from Friday's decision, understand the critical importance of providing additional guidance."

The steps that will allow for co-location could come from FERC, from RTOs or from the private sector parties pursuing the deals, he said.

Dominguez rejected criticism that co-located behind-the-meter data centers would not pay their share of costs to build and maintain grid capacity and would create capacity problems by diverting so much generation off the grid.

The data centers still would pay to support the grid, he said, and the nuclear reactors would switch their output back to the grid in times of emergency. Also, he said, if a co-located load had backup power, it could offer that power to the grid.

"These issues should be brought together and advanced at FERC," Dominguez said. "Frankly, I think part of the issue with the ISA proceeding is that it did not bring these issues together, and understandably, some of the commissioners want to see the complete package. We will pursue this regulatory clarity while simultaneously pursuing commercial strategies for co-location that are permitted under existing rules."

An analyst asked whether Constellation is broadening its strategy in the wake of the ruling.

"Our foot is on the accelerator, pressed all the way down on deals, whether they're front- or behind-the-meter," Dominguez replied. "Speed to market is very clearly the most important thing for customers, and so that's going to depend on the transmission configuration in different places, and certain places are going to be, frankly, more attractive [than] others for the data economy customers, and we're going to follow where they need to go."

Notable Quote

"They're not going to wait around for 10 years until somebody builds a power plant, transmission lines, to power the data economy. If that's the U.S. plan, then we've got bigger problems than picking the right RTO."

— Constellation Energy CEO Joe Dominguez

An analyst asked what sort of timeline Dominguez expects for gaining regulatory clarity on co-located loads.

Dominguez did not know — the FERC decision was not yet 72 hours old by that point, and most of those hours were weekend days.

"I probably would agree with you that there's not a quick fix," he said. "It's not going to happen tomorrow, but there are a lot of parties interested in moving this forward."

Dominguez added: "I think a bigger development wasn't the ISA, which was a narrow thing, but how do we deal with the comments that came out of the tech conference and craft something globally that addresses those comments?"

Another analyst asked whether hyperscalers would vote with their feet and look to build their facilities elsewhere, given slow movement in PJM.

"Where are they going to go? Right? It's not like it's a lot better anywhere else than PJM," Dominguez replied. "They're not slowing the pace of their investment, but what they're seeing is that there's no nirvana out there. There's no place where you could easily hook up the amount of energy that they're looking to hook up."

He added: "I'll tell you what won't be the solution, and I know this with absolute certainty: They're not going to wait around for 10 years until somebody builds a power plant, transmission lines, to power the data economy. If that's the U.S. plan, then we've got bigger problems than picking the right RTO." ■

Company News

Exelon Reports 80% Increase in Data Center Forecasts in 3rd-Quarter Earnings

By Devin Leith-Yessian

Estimates of data center growth across Exelon's service regions have increased by about 80% since the year began, executives said during the utility's third-quarter earnings call. They predicted steady growth in transmission upgrades and a regulatory battle to define the grid service costs applicable to data centers that co-locate with generators.

Calvin Butler, Exelon | *Exelon*

Exelon CEO Calvin Butler said it now forecasts 11 GW of high-probability data center load, up from 6 GW at the start of 2024. While that presents an opportunity for growth, he stressed that getting that load interconnected must be done in a coordinated, thoughtful and efficient manner to yield "transparent, forward-looking planning and ratemaking."

That goal underlies its advocacy at FERC, PJM and legislatures to ensure that co-located load configurations pay for any grid services they benefit from and are studied for any reliability implications. (See *Exelon, Constellation at Loggerheads over Data Center Co-location*.)

Data centers seek to co-locate with several nuclear generators in their search for carbon-free power, including Constellation's Calvert Cliffs Nuclear Power Plant in Maryland, Limerick Nuclear Power Plant in Pennsylvania and Talen's Susquehanna Nuclear Plant.

Exelon COO Michael Innocenzo said co-located configurations can have several impacts on the grid that would not be recognized under the proposals from Constellation and Talen. Those include ancillary services the load benefits from by nature of drawing off a generator that itself is interconnected, as well as grid upgrades that may be prompted by removing that capacity from PJM's system.

"Our whole position has just been — if they can co-locate, if they can get in there quick and get in there doing what they want to do, we support that. We just want to make sure that it has the appropriate transparency on what they are doing. We want to make sure that we have the appropriate studies done to make sure that we are addressing resource and reliability and adequacy currently, and we also want appropriate rate design to be able to cover for those costs, either now or in the future," Innocenzo added.

More generation also will be needed to meet that load growth, which Butler said will require changes to PJM's capacity market structure to ensure increasing costs don't compromise the goal of efficiently meeting demand. While Exelon is not advocating for an expansion of regulated generation, he said it's engaging in discussions with other utilities and regulators on the subject.

"And I do appreciate PJM's leadership to put forward interconnection and various capacity and market reforms. And it's just another example that the PJM stakeholder process is just not working. And we will continue to support them as well as other federal and regional agencies to get that done," Butler said.

Quarterly Earnings on Pace with Projections

Earnings continued to be on track to meet the utility's guidance of $2.40 to $2.50 earnings per share, with quarterly earnings 4 cents higher compared to the same period last year because of the timing of ComEd's distribution earnings. Higher distribution and transmission rates increased earnings another 3 cents, which were equally offset by higher interest rates.

Final orders on rate bases for ComEd and PECO are expected from the Illinois Commerce Commission and Pennsylvania Public Utilities Commission within the next few months, which would cover about half of Exelon's total base. Butler said the utility plans to make $34.5 billion in capital investments between 2024 and 2027, increasing its rate base by about 7.5%.

The use of multiyear plans in several states offers additional transparency and affordability for consumers and allows Exelon to build on its long-term plans more effectively, Butler said.

Exelon CFO Jeanne Jones said the utility's transmission projects already are leading to cost savings for consumers, with upgrades to bring the Vienna-Nelson from 138 kV to 230 kV running two years ahead of schedue. Once that's complete, Indian River Unit 4 will be able to finish its deactivation, potentially leading to an early end to a reliability-must-run contract with NRG Energy to keep the generator operational. If that agreement were to terminate two years early, Jones said it would save ratepayers nearly $100 million, more than 1.5 times the cost of the transmission upgrades. (See *PJM OC Briefs: July 11, 2024*.) ■

Company News

Dominion Reports More Data Center Growth, Offshore Wind Progress

By James Downing

Dominion Energy reported net income of $953 million in the third quarter this year as it continued to see load growth from data centers, made progress on its offshore wind project and repaired damage from Hurricane Helene.

The storm caused significant destruction of the company's infrastructure, knocking out power to nearly 450,000 customers, including nearly half of those Dominion serves in South Carolina, CEO Robert Blue told investors.

"The restoration involved replacing over 1,000 transformers, 2,300 poles and 7,000 spans of wire," Blue said. "Although we've not completed our final accounting, our preliminary estimate of restoration costs, including capital expenditures, is in the range of $100 (million) to $200 million."

Dominion's Coastal Virginia Offshore Wind (CVOW) is 43% complete and remains on schedule and on budget, Blue said. The firm just completed a season of monopile installations, having installed 78 for the project's turbines and an additional four pin piles for related transmission substations.

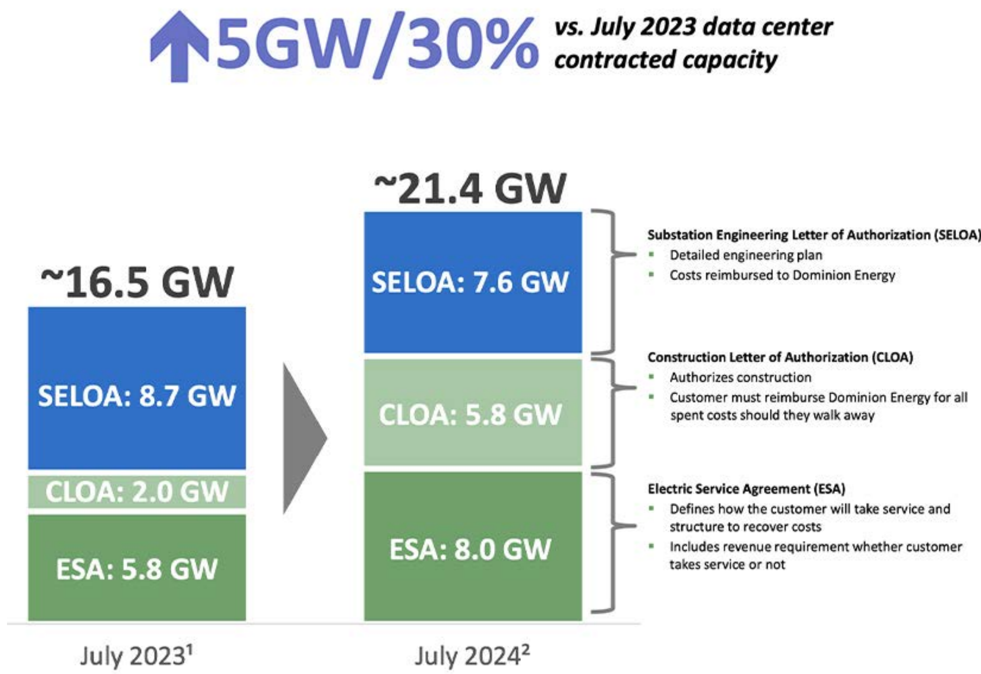
"Additionally, we've laid the first two of nine marine deep water export cables ahead of schedule," Blue said. "I'm very pleased with our progress during this first season. Not only did we achieve our installations target, we also gained invaluable experience and process expertise that will make the next installation season even more productive."

The rest of the monopiles are being produced and delivered to Portsmouth, Va., while Dominion expects nacelle and blade production to start in the first quarter of next year.

To help with offshore wind construction, Dominion is building a ship called Charybdis, which will be compliant with the Jones Act, a law that limits shipments inside U.S. waters to domestic vessels. The ship is 93% complete and should be operational by early 2025, Blue said.

Why This Matters

Dominion serves the largest data center market in the world and so far this year has interconnected 14 of the facilities, with another two expected to come online before the end of 2024.



| Dominion Energy

"The project's expected LCOE [levelized cost of energy] has improved to approximately $56 per megawatt hour," Blue said. "The primary driver being forecasted REC [renewable energy certificate] prices, which have increased in value considerably."

Dominion serves the largest data center market in the world, and so far this year, it has interconnected 14 of the facilities, with two more expected to come online before the end of 2024, Blue said.

"We're currently studying approximately 8 GW of data center demand within the substation engineering letters of authorization stage, which means a customer has requested the company to begin the necessary engineering for new distribution and substation infrastructure required to serve the customer," Blue said. "There are also about 6 GW of data center demand that have executed construction letters of authorization, which are contracts that enable construction of the required distribution and substation electric infrastructure to begin."

In total, the firm had about 21 GW of data centers in the more advanced stages of its planning process as of July, which was up from 16 GW a year earlier, he added.

"These contracted amounts do not contemplate the many data center projects that are in development phase and have not yet reached a point in the service connection process where a contract is executed," Blue said.

Dominion owns the Millstone nuclear plant in Connecticut, which could benefit clean energy legislation in New England, as neighboring Massachusetts is considering legislation that would authorize long-term contracts with it. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

"We've continued to engage with multiple parties there to find the best value for Millstone. In addition to state-sponsored procurement, we're exploring the idea of supporting incremental data center activity as well," Blue said. "We feel strongly that any data center option needs to be pursued in a collaborative fashion with stakeholders in Connecticut. At this point, we don't have a timeline for any potential announcements, but this remains top of mind for us." ■

Company News

Data Center Opportunity is Strong, Expanding, PSEG CEO Says

LaRossa Sees Demand Growth Despite FERC's Talen Energy Ruling

By Hugh R. Morley

The FERC ruling that blocked the proposed expansion of a data center in Pennsylvania isn't a hindrance to developing data centers in New Jersey, Public Service Enterprise Group CEO Ralph A. LaRossa said in a third-quarter earnings call Nov. 4.

LaRossa said PSEG has received a surge in project inquiries and proposals and is well positioned due in part to its spare nuclear generating capacity and a state tax-break program enacted in July.

On Nov. 1, FERC rejected an amendment to Talen Energy's interconnection service agreement (ISA) with PJM and PPL for a proposed expansion of Amazon Web Services' 300-MW data center in Pennsylvania. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

"We are aware of the FERC technical conference and decision on Friday," LaRossa said, adding that "we will continue to look for clarity on this issue going forward. That said, we believe that data center demand will continue to grow."

PSEG is the sole owner and operator of the Hope Creek nuclear plant in Salem, N.J., and the operator and majority co-owner of two adjacent nuclear plants, Salem 1 and Salem 2, with Constellation Energy the minority co-owner. The company considers the three plants key to its ability to meet the future needs of data centers and artificial intelligence development projects, which the state's economic development planners also are courting. (See *PSEG Plans for 80-year Nuclear Generation in NJ*.)

PSEG's Hope Creek and Salem nuclear plants | *Peretz Partensky, CC BY 2.0, via Wikimedia Commons*

LaRossa called the FERC ruling on the Talen Energy project a "very narrow decision" that was "specific" only to the facts put forward by the parties involved in the Pennsylvania case.

"It has not slowed us down, and will not slow us down, from trying to help the state of New Jersey meet their economic development goals," he said. "We continue to pursue contracting of our nuclear output at long-term, attractive pricing with low execution risk that can also help attract new technology-based businesses to New Jersey."

The utility's nuclear fleet has room for expansion and the utility is "pursuing thermal inefficiency upgrades" that could increase the output of the three Salem units by 200 MW, LaRossa said.

Co-location Factors

LaRossa said the utility recently updated the load study, part of an annual submission to PJM, which reflects the interest in putting data centers in the territory served by the utility.

"Our existing data center peak load currently stands at approximately 350 MW, and these sites are expected to expand by about 170 MW over the next 10 years," he said. "We have also received formal applications to initiate nearly 400 MW of new data center load and inquiries over 1,200 MW of data center feasibility studies in new business.

"These amounts do not represent firm commitments, but they provide an indication of the increase in interest," he said. He cited the example of an *announcement* by Roseland, N.J.-based CoreWeave that it had signed a lease to convert a 280,000-square-foot former laboratory and manufacturing building into a $1.25 billion data center.

"New Jersey has numerous locations that can be re-utilized in a similar fashion, and the state's economic development efforts are focused on replicating this activity throughout the state," he said. Potential developers are likely to be swayed in varying amounts by three factors, he said: to what extent a project represents "additionality," or the creation of new renewable energy; the time it will take to get the project up and running; and the reliability of the energy source.

Why This Matters

PSEG says its three nuclear power plants have room for expansion and can benefit from thermal efficiency upgrades. The company considers the plants key to meeting the future needs of data centers and artificial intelligence development projects.

"We believe we're in pretty good shape on all three of those factors," he said. "And that's why we haven't indicated at all that we're backing down."

He said the utility is open to co-locating a data center next to one of the nuclear plants, for which potential clients typically would look at factors such as how much the utility charges for the energy and the transmission, and at the level of taxes. Those factors will determine whether the state can attract a "hyperscaler," or large-scale data center, to the area, he said, noting that Gov. Phil Murphy (D) in July *signed a law* that would allocate $500 million a year in tax breaks to artificial intelligence data centers.

In a separate issue, LaRossa said PSEG has submitted a proposal to the New Jersey Board of Public Utilities (BPU) offshore infrastructure solicitation, the results of which are expected to be released by the end of 2024. (See *NJ Offshore Infrastructure Plans Spark Electromagnetic Fears*.)

The utility also submitted bids to PJM's 2024 Regional Transmission Expansion Plan *Window 1*, LaRossa said. The solicitation seeks proposals to meet the RTO's needs stemming from ongoing load growth.

PSEG's third-quarter results for 2024 exceeded those in 2023. The company reported net income of $520 million ($1.04/share), compared with $139 million ($0.27/share). Non-GAAP operating earnings for Q3 2024 were $448 million ($0.90/share), compared with $425 million ($0.85/share) in the same period in 2023. ■

Company News

NCUC Approves Latest Duke 'Carbon Plan' to Expand Renewable, Nuclear and Gas Generation

By James Downing

Why This Matters

Trying to balance the cutting of carbon emissions while maintaining system reliability can be tough. The NCUC order was criticized by those who want the state and Duke to move faster to cut emissions.

The North Carolina Utilities Commission issued an order Nov. 1 approving Duke Energy's consolidated Carbon Plan and Integrated Resource Plan (CPIRP), which is meant to meet state-mandated carbon emission cuts and improve system reliability.

The plan was the first biennial CPIRP since NCUC approved the initial one at the end of 2022. Determining the least-cost path to cutting carbon emissions while maintaining system reliability is a complex and iterative process, the regulator said.

NCUC has directed Duke to pursue every opportunity, including tax incentives and federal funding, to cut costs for consumers. Duke has delivered electricity at rates below the national average for decades, and the regulator said it would work to ensure that record is maintained.

The order waived the requirement to model a 70% carbon cut by 2030, agreeing to extend that to 2032 and telling Duke to pursue 70% carbon cuts by the earliest date possible.

The order approves a settlement between Duke and the commission's Public Staff, which is the state's consumer advocate. The settlement also was agreed to by Walmart and the Carolinas Clean Energy Business Association.

"We believe this is a constructive outcome that allows us to deploy increasingly clean energy resources at a pace that protects affordability and reliability for our customers," Duke said in a statement on the CPIRP. "The order confirms the importance of a diverse, 'all of the above' approach that is essential for long-term resource planning and helps us meet the energy needs of our region's growing economy."

The CPIRP requires Duke to retire its remaining coal plants, which total more than 8,000 MW, by 2036.

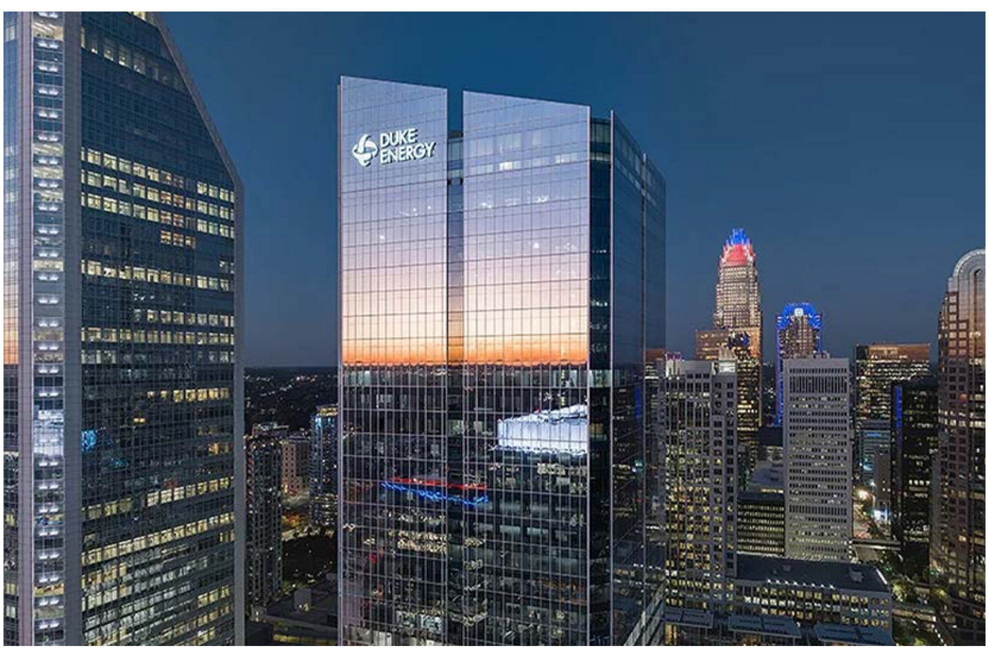
Duke will conduct two competitive solar procurements in the next two years, targeting 3,460 MW of new solar generation that can be placed into service by 2031. It also will procure 1,100 MW of battery storage, which includes 475 MW of standalone storage and 625 MW paired with solar, to come online by 2031.

The order calls for Duke to procure 1,200 MW of onshore wind to come online by 2033, including at least 300 MW targeted for commercial operation by 2031.

NCUC approved new natural gas capacity as well, with 900 MW of combustion turbines to be developed by 2030 and 2,720 MW of combined cycle capacity coming online by 2031.

Duke will try to build 1,834 MW of pumped storage hydropower at the Bad Creek Hydroelectric station in South Carolina, which would be placed into service by 2034.

The order authorized early development of 300 MW of advanced nuclear generation to go into service by 2034 and an additional 300 MW for the next year. Duke also was authorized to work on extending its operating licenses for its existing nuclear plants.



| Duke Energy

For offshore wind, the CPIRP authorizes Duke to start gathering information regarding the development of up to 2,400 MW off the North Carolina coast to be in commercial operation by 2035.

The order also requires Duke to continue planning for a 1% load reduction through demand-side management and energy efficiency. It calls on Duke to work with large customers to manage load for the benefit of all customers.

Commissioner Jeffrey Hughes filed a concurrence saying that while the order will lead to benefits, the NCUC could have spent more time analyzing the potential costs associated with climate change.

"I would have liked to see more acknowledgement that producing carbon emissions, whether directly through the combustion of gas or coal or indirectly through the production and delivery of those fuels, carries a significant economic cost in terms of climate change," Hughes said.

The order was criticized by those who want the state and Duke to move faster to cut emissions. The nonprofit Ceres, which encourages investors to address climate change, welcomed the required clean energy procurements but objected to the time frame.

"Leading businesses across North Carolina have supported the state's plan to reduce power sector emissions by 70% by 2030, both to reduce their own exposure to climate risk and to experience the economic benefits of clean energy investment," said Ceres Director of State Policy Mel Mackin. "This decision not only delays that goal, but it also sets a worrying precedent." ■

Company Briefs

Ford to Idle F-150 Lightning EV Plant for Weeks

Ford Motor last week said it will idle its F-150 Lightning electric truck plant in Dearborn, Mich., from mid-November through the end of the year as the automaker continues to deal with slower-than-expected EV demand.

Production will pause Nov. 15 and resume Jan. 6, a Ford spokesperson confirmed. Ford did not confirm how many workers would be impacted.

Ford said in August it is changing its EV strategy after losses mounted and said it is prioritizing the introduction of an all-electric commercial van and delaying the launch of a full-size EV pickup.

More: *Detroit Free Press*

Amazon, Dominion to Explore Nuclear Development

Amazon and Dominion Energy announced they have agreed to explore the potential development of small modular nuclear reactors (SMRs) at North Anna Power Station in Virginia.

The companies' memorandum of understanding means they will "jointly explore innovative ways to advance SMR development and financing while also mitigating potential cost and development risks for customers and capital providers," according to an announcement.

Only two SMRs are in operation worldwide — one in Russia and the other in China — and Virginia likely won't have its own before the mid-2030s.

More: *Virginia Business*

Meta, Engie Agree to Solar PPA

Facebook owner Meta Platforms last week announced it will buy all the output of Engie's planned 260-MW Sypert solar plant.

The plant, which will be built in Milam County, Texas, is expected to be operational in 2025.

More: *Reuters*

Company Submits Pipeline Expansion Plans to FERC

Williams Companies last week applied to FERC for the Transco Pipeline Expansion, which is part of a massive expansion of natural gas infrastructure proposed for the Southeast.

The project would include 26 miles of pipeline in Virginia and 28 miles in North Carolina.

The company aims to begin construction in fall of 2026 and begin service in 2027.

More: *Augusta Free Press*

Federal Briefs

DOE to Award $150M for Energy Upgrades at Federal Facilities

The DOE announced it has released $149.87 million in funding for 67 energy conservation and clean energy projects at federal facilities across 28 states and territories, as well as six international locations.

The funds represent the second installment of a total of $250 million under the Assisting Federal Facilities with Energy Conservation Technologies (AFFECT) grant program. The projects include installing battery storage systems, microgrids, building automation systems and integrating renewable energy sources.

More: *Energy.gov*

Federal Appeals Court to Hear TVA's Cumberland Pipeline Case

A federal appeals court will hear arguments in December over the future of a proposed Tennessee Valley Authority pipeline supplying the planned Cumberland Gas Plant in Tennessee.

The 6th Circuit Court of Appeals voted 2-1 in October to temporarily freeze two permits issued to the Tennessee Gas Pipeline Company to begin construction of the pipeline, which would cross 149 streams, creeks and wetlands, until the court can consider arguments about the environmental impact of construction.

The 32-mile pipeline is needed to supply methane gas to TVA's Cumberland Gas Plant as it replaces coal-burning plants with methane gas plants.

More: *Tennessee Lookout*

National/Federal news from our other channels

CISA Releases International Strategic Plan

ERO Insider

Panelists Discuss Electric, Election Security Intersections

ERO Insider

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

State Briefs

FLORIDA

Stuart Boards Approve Line Burying Project

Three Stuart city boards approved a $9.3 million project to bury power lines.

The City Commission, Community Redevelopment Agency and Community Redevelopment boards voted to move ahead with work that is set to begin in March.

More: *Treasure Coast Newspapers*

GEORGIA

Georgia Power Proposes Storage Systems to PSC

Georgia Power last week filed a proposal with the Public Service Commission to build four battery energy storage systems totaling 500 MW.

The utility plans to construct two of the facilities adjacent to the Robins Air Force Base and Moody Air Force Base. A third would be located at Georgia Power's retired coal-fired Plant Hammond, while the fourth facility would double the storage capacity at the McGrau Ford Battery Facility currently under development.

The PSC is scheduled to vote on the projects in December.

More: *Capitol Beat News Service*

MASSACHUSETTS

Ratepayers to Pay More for Hydro Due to Maine Political Delays

Avangrid and the state's three utilities last week filed paperwork with the Department of Public Utilities seeking an additional $521 million from ratepayers to cover construction delays costs caused by a political dispute in Maine over the New England Clean Energy Connect transmission line.

Construction was shut down in November 2021 after Maine voters approved a law retroactively blocking the line from being built. Nearly two years later, the project was given a green light to resume construction when courts ruled the voter approved law violated the state's constitution.

The added costs bring the project's total cost to $1.5 billion.

More: *CommonWealth Beacon*

MISSOURI

Ameren: Rush Island Site Not for Sale

Ameren officials said they are not planning on selling the Rush Island Energy Center despite it being retired on Oct. 15.

On Sept. 30, 2023, the U.S. District Court for the Eastern District of Missouri ordered Ameren Missouri to retire the Rush Island Energy Center no later than Oct. 25, 2024, and terminate boiler operations no later than Oct. 15.

Plans for the site remain unknown, but the connectivity to the grid makes the land too valuable for Ameren to sell.

More: *Spectrum News*

Court Rejects Grain Belt Express Tx Line Appeal

The Missouri Western District Court of Appeals last week rejected an attempt by state farming organizations to block construction of the Grain Belt Express line.

Agriculture organizations including the Missouri Farm Bureau, the Cattlemen's Association and the Missouri Soybean Association asked the court to return the Public Service Commission's approval to a lower court for further testimony on the value of the project. However, the three-judge panel said previous court decisions were adequate.

More: *St. Louis Post-Dispatch*

Fire Erupts at Lithium-ion Battery Recycling Plant

Residents of Fredericktown were forced to evacuate their homes last week when a fire erupted at Critical Mineral Recovery's lithium-ion battery recycling plant.

Photos showed Critical Mineral Recovery, one of the world's largest lithium-ion battery processing facilities, with a hole in its partially collapsed roof and smoke billowing from the building.

According to the company's website, the plant processes electric vehicle and consumer-grade lithium-ion batteries and retrieves valuable metals and minerals.

More: *Missouri Independent*

PSC Approves Proposed Ameren Gas Plant

The Public Service Commission last week approved Ameren's plans to build a $900 million natural gas-fired power plant in St. Louis County.

PSC members agreed that the new Castle Bluff plant, which will replace Ameren's former coal-fired Meramec Energy Center, is needed to deal with potential shortfalls in the St. Louis area and other parts of the state.

Construction is slated to begin in the coming weeks, and the plant is expected to start operating in 2027.

More: *St. Louis Post-Dispatch*

NEW MEXICO

Bernalillo County Approves IRB for Battery Storage Project

The Bernalillo County Board of County Commissioners approved an ordinance to issue $190 million in industrial revenue bonds for the Sun Lasso Energy Center.

The battery storage project developed by Aypa Power will be a four-hour system with a 150-MW capacity.

Construction is slated for 2025, with operations beginning in 2027.

More: *Energy Storage News*

OREGON

NW Natural Ordered to Phase Out New Gas Connection Subsidies by 2027

The Public Utilities Commission last week ordered NW Natural to phase out subsidies for new gas customers by Nov. 1, 2027.

The order comes ahead of an upcoming ruling about gas rates and features decisions about costs that are allowed to affect how much customers pay. The commission expects to announce NW Natural's approved rates soon, as well as rate decisions for other regulated gas utilities.

Conversely, NW Natural said eliminating the line extension allowance would be an "extreme measure and that no Oregon law limits the growth of the natural gas system" and that it's too soon to "prejudge" the future of the gas system. The company is still reviewing the order.

More: *Oregon Public Broadcasting*

TENNESSEE

Memphis Opens Green Bank

The city of Memphis officially opened a green bank last week intended to fund energy efficiency, green infrastructure and renewable energy projects.

The bank plans to roll out several programs aimed at upgrading homes and businesses with energy saving projects.

The bank received $150,000 in seed funding from the Tennessee Valley Authority and is seeking to secure a $20 million grant from EPA.

More: *WREG*

VIRGINIA

Energy Storage Projects Slated for Greensville, Pittsylvania

Two energy storage projects proposed for Southern Virginia recently received approvals in their respective areas.

The State Corporation Commission approved Dominion Energy's request to build a $548 million liquified natural gas storage facility next to its Greensville County natural gas power plant. Dominion aims to open the facility in 2027.

Elsewhere, Strata Clean Energy received approval from the Danville-Pittsylvania Regional Industrial Authority to lease 85 acres at the Southern Virginia Megasite to build a lithium-ion battery storage facility. Construction is slated to begin in 2026.

More: *Virginia Business*

Powhatan Approves $2.7B Data Center Project

Powhatan County supervisors voted 3-2 to approve a $2.7 billion data center campus.

Developer Province Group's plans call for three data center buildings, totaling some 1.5 million square feet of space, north of Route 60. Dominion Energy said it will need to install a new substation and power lines to supply the buildings.

The approval went against a planning commission recommendation to deny the rezoning and conditional use permit.

More: *Richmond Times-Dispatch*

WEST VIRGINIA

PSC Approves Mountaineer Gas, Hope Gas Rate Hikes

The Public Service Commission has approved rate increases for utilities Mountaineer Gas and Hope Gas.

Hope Gas customers will see an increase of $6.08 (6.3%), while Mountaineer Gas bills will go up by $2.63 (2.9%). Other companies receiving an increase were Peoples Gas (6.1%), Southern Public Service (7%) and Standard-Bazzle (7.4%).

All five companies noted infrastructure replacement, upgrades and expansions are reasons for their requests.

More: *Charleston Gazette-Mail*

WYOMING

Legislature Rejects Bills Limiting Eminent Domain

The Joint Agriculture, State and Public Lands Committee rejected two bills that would have restricted the use of eminent domain to acquire land for carbon capture, wind and solar projects.

The committee voted 9-6 to reject a bill that would have prohibited public and private entities from using eminent domain to install pipelines transporting carbon dioxide for the purposes of carbon capture use or storage. The committee also voted 10-5 to reject another bill that would have allowed some level of eminent domain to continue for the installation of electric collector systems for wind and solar energy.

More: *Cowboy State Daily*