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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: BPA transmission line on the Oregon side of the Columbia River Gorge |

RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

RTO Insider LLC

2415 Boston Street
Baltimore, MD 21224
(301) 658-6885

In this week's issue

Counterflow

By Steve Huntoon

More Stuff That Ain't So

By Steve Huntoon

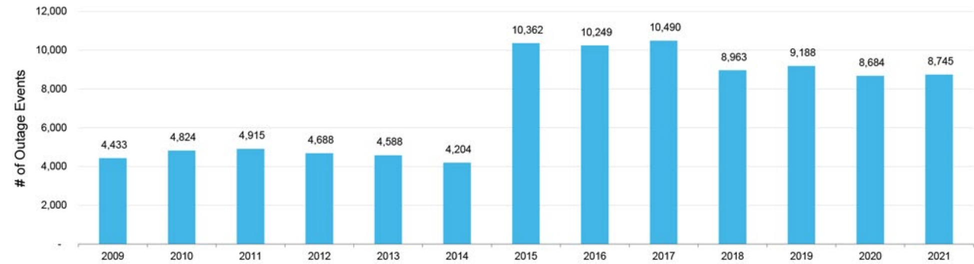
The misinformation in our industry is pervasive. Daily headlines are loaded with stuff from reports, studies and news releases that just ain't so.

Let me give an example of a recent Moody's report on transmission.[1] (See *Moody's: Permitting Process Holding Transmission Back, Risking Reliability*.)

Moody's bases its case for investment in transmission in part on aged infrastructure causing reliability and other problems. Let's check out its claims.

Transmission Outage Events

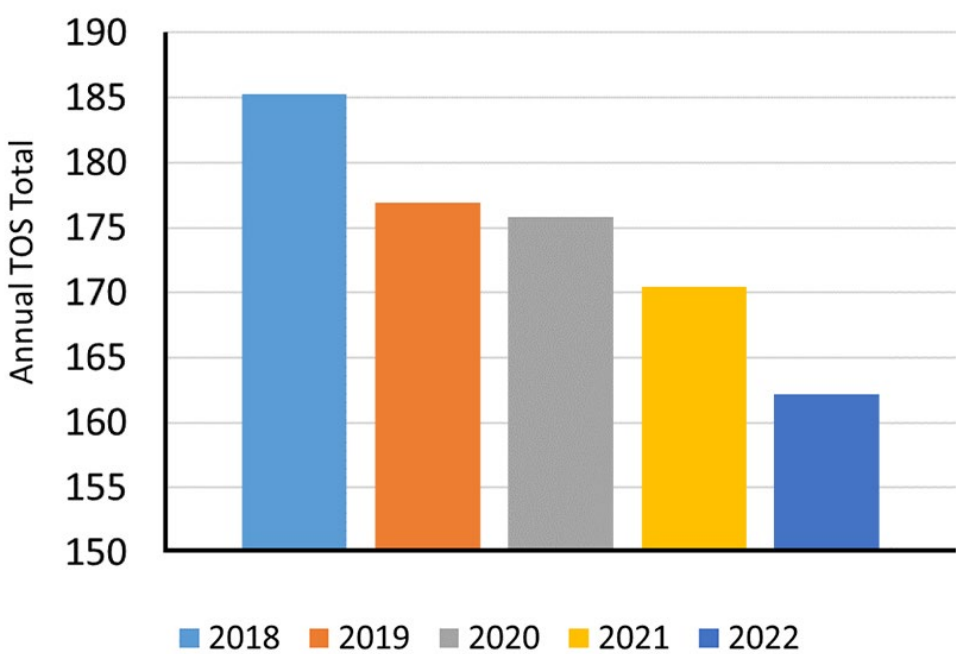
Exhibit 1 from its report is reprinted here on the right, with Moody's saying that transmission outage events have more than doubled between 2009-2014 and 2015-2021.



Citing NERC data, Moody's claimed transmission outage events 'have increased dramatically since 2014 primarily due to an increase in extreme weather.' | *Moody's*

This is not valid analysis. Starting in 2015, NERC expanded the facilities subject to reporting from 200 kV and above, to 100 kV and above.[2] The number of facilities (elements) subject to reporting increased from 7,098 to 23,835, and the number of subject circuit miles increased from 181,427 to 454,316.[3] So the increase in reported outages has everything to do with a larger number of subject facilities and circuit miles, and nothing to do with transmission system reliability.

NERC provides the trend in transmission system reliability in the chart reprinted below, saying that: "The Bulk Electric System (BES) transmission system continues to demonstrate significantly improved reliability for the fifth year in a row.[4]"



NERC reported that transmission system reliability, as measured by overall transmission outage severity (TOS), has improved continuously over the past five years. | *NERC*

Congestion

Congestion is the additional cost of dispatching higher cost generation due to a transmission constraint. Moody's says that congestion costs in the Mid-Atlantic region surged from $528.7 million in 2020 to $995.3 million in 2021, surpassing "energy costs."

The increase in congestion costs from 2020 to 2021 had everything to do with increases in fossil fuel costs (energy clearing prices increased from $21.77/MWh to $39.78/MWh largely due to higher fuel and emission costs)[5] — nothing to do with transmission system inadequacies.

As for the claim that congestion costs of $995.3 million exceeded energy costs, energy costs were $30.5 billion in 2021.[6] So congestion costs were a minor 3% of energy costs, hardly *more* than energy costs. And customers were shielded against much of those relatively minor congestion costs through financial transmission rights.[7]

Moody's sources its invalid congestion claims to DOE's draft "National Transmission Needs Study," so let me address a couple more misjudgments that appear there.[8] DOE says the "transmission constraint shadow price" almost doubled from 2020 to 2021. This simply reflects higher fuel prices. How do we know that? Because the frequency of transmission constraints actually declined from 117,867 to 102,529.[9]

Then DOE says that in 2021 the "transmission price component" was more than the "capacity price component" for the first time since 2007, which isn't exactly true, but in any event would suggest transmission system spending is going *up – a non sequitur* for any claim of growing transmission inadequacy.

Counterflow

By Steve Huntoon

Transmission Facilities' Life Expectancy

Moody's says that transmission lines and transformers are mostly beyond their life expectancies.

Regarding its claim that transmission lines have a life expectancy of 50 years, the reality for transmission lines is 80+ years[10] to "essentially forever.[11]"

Regarding its claim that transformers have a life expectancy of 25 years, the cited authority states that this is based on continuous loading at the rated (maximum) capacity,[12] which simply does not happen. The reality is that transformers on average last much longer than that.[13]

BTW, the most important reliability element for transformers is that we maintain an inventory available to replace transformers as failures occur. (hint to RTOs and TOs: Any transformers retired before failure should be kept in reserve for this purpose.)

Texas

Moody's is right about one thing: Interregional transmission ties into Texas would have avoided vast costs and outages during Winter Storm Uri (not to mention saved lives).

But as I have written before, that problem has to do with Texas' self-imposed isolation because of its (groundless) concern about losing Texas' independence.[14] Nothing to do with transmission system inadequacies.

Bottom Line

We should keep the current condition of the transmission system — which is generally sound — separate from the need to expand the system for the energy transition. I've had a few thoughts on the latter for anyone interested.[15] ■

Columnist Steve Huntoon, principal of Energy Counsel LLP, and a former president of the Energy Bar Association, has been practicing energy law for more than 30 years.

[1] https://www.moodys.com/research/Regulated-Electric-and-Gas-Utilities-US-Transmission-investment-opportunities-abound-Sector-In-Depth--PBC_1377533.

[2] https://www.energy.gov/oe/articles/annual-us-transmission-data-review-2015, page 3 and footnote 6.

[3] https://www.nerc.com/pa/RAPA/tads/SiteAssets/TADS_Dashboard_Supporting_Data.xlsx, columns under "Inventory Counts."

[4] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Overview.pdf, page 11.

[5] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf, page 1.

[6] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf, page 18, Table 8.

[7] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf, page 72.

[8] https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf, page 64.

[9] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec3.pdf, page 175, Table 3-54.

[10] https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/OverheadVsUnderground_FactSheet.pdf

[11] https://engineering.mit.edu/engage/ask-an-engineer/how-do-electricity-transmission-lines-withstand-a-lifetime-of-exposure-to-the-elements/; https://www.tdworld.com/intelligent-undergrounding/article/21215620/overhead-or-underground-transmission-that-is-still-the-question.

[12] https://www.electricaltechnology.org/2019/12/average-life-expectancy-transformer.html

[13] https://teamuis.com/2021/01/07/how-long-does-a-power-transformer-last-forever/

[14] https://www.energy-counsel.com/docs/a-modest-proposal.pdf

[15] https://energy-counsel.com/wp-content/uploads/2023/02/Big-Transmision-Still-Not-the-Right-Stuff.pdf; https://energy-counsel.com/wp-content/uploads/2022/04/Stop-the-Insanity.pdf.

FERC/Federal News

ISOs/RTOs Oppose Call for Capacity Accreditation Tech Conference

IRC: Conferences Can Help, but Variation, Frameworks Complicate Consensus Goal

By James Downing

A call for FERC to run a technical conference on capacity accreditation ran into a mixed reception in comments filed this week, with the ISO/RTO Council saying it is too regional of an issue for the idea to have an impact (AD23-10).

The American Clean Power Association filed a petition in August calling for the conference, arguing that capacity accreditation was something worth looking at holistically. (See *ACP Asks FERC for Capacity Accreditation Technical Conference*.)

"While the members of the IRC acknowledge that commission-led technical conferences can often be beneficial and understand the concerns raised by ACP in its petition, the regional variation on matters related to resource adequacy renders the topic of capacity accreditation less well suited for a national forum intended to drive toward 'consensus,'" the IRC said. "As capacity markets themselves are neither mandatory nor standardized — reflecting regional differences in priorities and reliability needs — so too are the various accreditation frameworks that operate within each capacity market."

Regions outside organized markets without capacity markets are even more distinct, which means a technical conference applicable to all would have limited value, it added.

Every FERC-jurisdictional ISO and RTO is talking about capacity accreditation modifications for a variety of reasons, and some of those processes contemplate a filing this year or next. Holding a technical conference likely would delay those changes, which are of "vital importance."

The IRC said it was sympathetic to the issue of *ex parte* restrictions on commissioners discussing the topic, but it noted that no proceeding was open at this point that would lead to any issues.

"But should one arise, the commission could turn to alternative procedures that would not require a national technical conference to discuss individual ISO/RTO proposals," IRC said. "For example, commission staff can notice a meeting to gather additional information about the unique reliability concerns facing a particular ISO/RTO to assess proposed capacity accreditation reforms."

The Electric Power Supply Association told FERC it is not opposed to a technical conference and it supports broad engagement on system planning and resource adequacy. But like the IRC, it cautioned FERC about the idea's impact on the ongoing stakeholder processes.

"Those processes are the result of extensive stakeholder participation and negotiation and are tailored to the region's specific needs; for this reason, the commission should take care to both timing and framing a technical conference such that it supports — rather than stymies — this regional progress," EPSA said.

Colorado Public Utilities Commission Chair Eric Blank wrote to FERC in support of holding a technical conference, saying it would help given all the changes happening on the Western grid. The PUC is working to facilitate a transition that economically reduces greenhouse gases over time while also moving toward more regional cooperation through expanded markets.

"Taken together, these forces will likely result in a significant increase in interregional transfers, an expansion in alternative generator and customer supply structures, and greater investment in intermittent and customer-sited resources, all of which present new challenges for maintaining resource adequacy," Blank said.

Capacity accreditation may need to change from analyzing a few hours of peak demand in a deterministic way to dynamically evaluating in a probabilistic way the value of individual resources during more frequent tight supply conditions, he added.

The Solar Energy Industries Association told FERC a conference is a good idea given the changes the industry is going through.

"Regions are shifting from a single summer peak to biannual summer and winter peaks, with climate change exacerbating the reliability risks associated with these changes," SEIA said. "The risk of correlated outages of thermal resources during extreme weather events is becoming more commonplace, and capability during extreme weather events is now the biggest risk to the reliability of the grid."

Advanced Energy United said it would like FERC to offer guidance on the patchwork of capacity accreditation rules around the country and thus supported the technical conference.

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"Existing ongoing efforts — which will continue to be iterated on for years at RTOs/ISOs — point to the need for a technical forum to holistically discuss issues and challenges related to capacity accreditation that have and will continue to arise," AEU said. "Existing processes to accredit capacity are inconsistent and leave out some of the important issues raised by ACP in its petition."

Sierra Club, Earthjustice, RMI, the Natural Resources Defense Council and the Sustainable FERC Project filed joint comments arguing a national technical conference on capacity accreditation would be worth FERC's time.

"This subject is also a matter of substantial public interest as policymakers at all levels strive to maintain affordable electric rates while grappling with increasingly frequent extreme weather that threatens reliable electricity supplies," the groups said. "Accurate capacity accreditation is key to a successful transition from conventional generation resources to a more decentralized and lower-emitting resource mix broadly supported by consumers and many state and local policies."

The current patchwork might reflect legitimate regional and operational differences, but FERC hasn't examined whether that's the case or whether the different rules undermine reliability and skew investment decisions in a way that doesn't benefit customers, they added. ■

FERC/Federal News

Transmission Expansion Runs into an Old Debate: Planning vs. Markets

Monitors Say Transmission Lines Rarely Regretted

By James Downing

| Entergy

Hardly a week passes without some organization releasing a study touting the benefits of a huge and rapid expansion of the transmission grid.

Indeed, the idea that the grid needs a rapid expansion to tap renewable resources and decarbonize is an article of faith in the power industry. But opposition to it is not limited to climate-science doubters and fossil fuel interests. (See *Counterflow: Big Transmission — Still Not the Right Stuff.)*

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

Both PJM Independent Market Monitor Joe Bowring and Potomac Economics President David Patton, whose firm provides market monitoring for four ISOs and RTOs, have pushed back on the need to rapidly expand the grid.

"Obviously, I'm an economist, and I believe in energy markets," Patton said. "And the thing about transmission when you're planning, and then building transmission and guaranteeing cost recovery, is, it's all happening outside the market."

While both energy economists agreed that the transmission and distribution systems require central planning, they said it is far from a perfect process and can interfere with cheaper solutions produced by the markets.

"One of the tensions that's always existed in the PJM market from the very beginning is the tension between competitive generation and non-competitive transmission," Bowring said. "Generation and transmission do compete at the margin. Transmission can replace generation and vice versa."

The market monitors are not alone in this position. Vistra Energy, which owns 37,000 MW of generation and serves millions of customers over other firms' wires, has said the same thing. Vistra told FERC in *comments* on its still-pending regional planning Notice of Proposed Rulemaking (RM21-17) that the idea that all renewables should be located in resource-rich areas is "too simplistic."

"It may be more efficient to locate a new resource in a less resource-rich area where interconnection costs are lower," Vistra said. "The net levelized margin of the resource — including environmental attribute revenues, wholesale market revenue, land cost and net network upgrade costs — will drive efficient development. Ignoring the network upgrade costs ignores a potentially important part of the project economics picture and thus risks increasing overall costs to ratepayers."

While Vistra has an interest in protecting its fossil fuel generation's market share, it is not averse to the clean transition. This year, it purchased Energy Harbor's three nuclear plants, giving it 3,400 MW of carbon-free generation. (See *Vistra Pays More than $3 Billion for Energy Harbor*.)

FERC Transmission Planning NOPR

FERC's planning NOPR does not direct the agency to build out all the transmission possible, said Grid Strategies President Rob Gramlich, who has long advocated for grid expansion to address climate change.

"It says: Do an analysis that evaluates the trade-off between one approach that has a lot of remote cheap generation with transmission lines, and another option, that's more local generation with less spending on transmission — and find the sweet spot between those," Gramlich said.

Rob Gramlich, Grid Strategies | *© RTO Insider LLC*

Bowring does not sound so different when it comes to planning, saying it needs to be done centrally and rationally, accounting for the locations of load growth and the locations of generation. Where he splits with Gramlich is on how much the cost of interconnecting new resources should be socialized. Bowring says making developers pay for their interconnection gives them the incentive to locate in the right place, rather than requiring customers to subsidize their choice of location.

Burying our heads in the sand about the realities of the future resource mix and adding transmission in small increments will only increase the costs of the networked grid needed to ensure a technologically and regionally

FERC/Federal News

diverse portfolio that ensures reliable service 8,760 hours a year, Gramlich said.

"We just have to get away from this system of planning and network through the interconnection process. That doesn't work in any network in any part of our economy," he said.

CAISO's proposal to plan around zones with available transmission capacity now, or under construction — where some areas will be cheaper for interconnection customers than others — is a good example of how things should work, Gramlich said. (See *CAISO Proposal Seeks to Address Interconnection Backlog*.)

As a supporter of markets, Bowring has doubts about central planning generally, noting that PJM's regional process has gotten it wrong in the past. He cites the example of the Potomac Appalachian Transmission Highline (PATH).

The $2.1 billion, 765-kV "coal by wire" PATH project was approved by PJM in 2007 to run from a coal generator in St. Albans, W.Va., to New Market in Frederick County, Md. By 2011, however, PJM said the need for the line had moved several years beyond 2015 because of reduced load growth following the Great Recession. After ordering transmission owners to suspend work on the line pending a more complete analysis of all upgrades in its regional transmission plan, the PJM Board of Managers terminated it in 2012.

"Reality keeps changing. We don't know what the technology is going to look like 20 years from now," Bowring said. "Do we really want to spend billions of dollars right now on transmission lines based on assumptions about what the technology is going to look like and the level and location of loads?"

Gramlich rejects the notion that the grid would be overbuilt by utilities zealously seeking to expand their rate bases. He said utilities lack the incentives to construct the kind of large regional and interregional lines that may be subject to competition, instead favoring local facilities they can build with little oversight.

In many cases, utilities will look at major transmission as bringing in low-cost, cheaper generation that is going to compete with their own and they will try to actively block its development, he added.

PJM has seen a lot of spending on local transmission projects in recent years, a fact which has come up repeatedly in the debate around FERC's proposed reforms to planning and cost allocation. In September, the Ohio Consumers' Counsel filed a *complaint* with FERC that said utilities in that state alone have planned for $6 billion in local projects since 2017.

No Regrets?

MISO IMM David Patton | © RTO Insider LLC

One idea the two market monitors pushed back against was that rarely is a transmission line built that winds up being regretted. While any transmission will be used when it is built and lead to lower congestion on the system, sometimes it is not the best choice.

"The goal is not just to eliminate congestion, it's to eliminate congestion that has costs higher than the cost of building transmission to eliminate it," Patton said. "And in some cases, there are other solutions that are much cheaper than transmission that the markets will facilitate."

Storage, for instance, can deal with congestion either by co-locating with renewable energy or by being built by itself elsewhere on the grid. And while storage might be the best option, overzealous transmission construction outside the market could cause battery developers to abandon such projects, Patton said.

Bowring does not think congestion is a useful metric to justify building transmission, a point his firm, Monitoring Analytics, has made in its state of the market reports. Congestion is ephemeral and locational, and it changes all the time, Bowring said.

"Congestion is not a reason to build transmission," Bowring added. "Congestion is just the difference between what load pays and generation receives. … So, congestion is zero sum already; it's not really a metric for anything. If the [financial transmission rights] market worked as intended, load would be repaid 100% of congestion."

Former FERC Chair Richard Glick said some of the leadership at ISO/RTOs is on board with expanding the grid, noting that MISO CEO John Bear has been *advocating* for years for transmission expansion to connect renewables. The queues are dominated by renewable energy projects or hybrid projects where renewables are paired with storage. (See *LBNL: Interconnection Queues Grew 40% in 2022*.)

"When someone like John Bear from MISO says we desperately need this transmission buildout to keep the lights on, I believe him," Glick said. "You don't want to overbuild. But I would say that the consequences of underbuilding are a lot worse than the consequences of overbuilding."

MISO is home to some of the best wind in the country, but those resources are far from major cities. In contrast, the renewables in PJM tend to be closer to load and therefore require less incremental transmission than in other regions of the country, Bowring said. The one exception to that in PJM is offshore wind.

"I don't understand why anyone believes that copper plating PJM, or any area, is the solution to adding renewables," Bowring said.

California used to think it could rely largely on in-state renewable energy to meet its policy goals. But while there are plenty of resources that will continue to be connected locally, policymakers have moved on from that narrow view as the share of renewables has grown, Gramlich said.

"If you do the math, it turns out that Idaho wind and Wyoming wind, and Salton Sea geothermal, New Mexico solar and wind — those complement the resources we have in state. And if you take into account the value of those, and the cost of transmission, it turns out, those are beneficial for California consumers," Gramlich said. "So, then CPUC has directed utilities to buy power from those areas and the California ISO is tasked with figuring out the transmission to those areas. That's the way to do it. In MISO, it's a similar analytical exercise."

That way of thinking is not isolated to California. Vermont PUC Commissioner Riley Allen, who sits on the FERC-State Task Force on transmission, said in an interview that while local issues like job creation are important, getting the best, most efficient mix of resources should guide transmission planning.

"The economics favor locating capacity and resources where it is inexpensive, and exploiting those opportunities sensibly, while recognizing that these resources are also going to be weather dependent and … using the grid as a mechanism that helps to ensure that no one location is dependent on resources from just one area, it adds an element of diversity that is hard to achieve otherwise," he said.

While adding renewables to the grid will require some transmission, Patton argued that economics should guide its development more than a centralized plan.

"If we get more and more renewables, and they cause more and more congestion, we should continue to evaluate transmission the same way, which is, you know, is it cost effective to build transmission?" Patton said. "And when the answer is yes, we should build it and then the answer is no, or there's some lower cost solution, we should not build it." ■

CAISO/West News

Plan Seeks to Boost Prospects for New Transmission in the West

Concept Paper for Western Transmission Expansion Coalition Proposes Two Committees, One Task Force

By Robert Mullin

The Western Power Pool (WPP) last week floated a proposal to revamp transmission planning in the West with the aim of spurring development of the kind of large-scale transmission projects FERC's Order 1000 process has failed to produce.

The proposal, which WPP laid out in a *concept paper*, envisions creation of a new group, the Western Transmission Expansion Coalition (WTEC), which would "explore a new approach for West-wide transmission planning that will result in an actionable transmission plan to address regional and interregional needs."

The paper says that while the region's current planning processes overseen by NorthernGrid in the Northwest, WestConnect in the Southwest and CAISO comply with FERC requirements, "the legal and regulatory structure upon which they were built is limited and has not resulted in the identification of new transmission solutions that result in transmission builds.

"The limited nature of regional planning also handicaps the broader West in developing inter-regional transmission solutions. To effectively address the collective needs of the grid for the future, transmission planning must be performed in a more holistic and coordinated manner, such that a plan for transmission expansion solutions can be optimized to meet a broader set of needs," the paper says.

WPP spokesperson Kevin Langbaum told *RTO Insider* that participants in "informal" conversations that produced the plan included WPP, BPA, the Pacific Northwest Utilities Conference Committee (PNUCC), the Northwest & Intermountain Power Producers Coalition (NIPPC), the Public Power Council (PPC), PacifiCorp, Idaho Power, Portland General Electric, Snohomish PUD, Puget Sound Energy and clean energy advocacy group Renewable Northwest.

"At the request of leadership from the Bonneville Power Administration (BPA) in response to stakeholders' urging and supported by leadership of several energy industry entities and utilities, an informal group formed to discuss approaches to address a widely recognized concern that current transmission planning frameworks in the West do not result in sufficient transmission solutions to support the needs of the future energy grid," the WPP said in describing the proposal.

The concept paper defines an "actionable" transmission plan as one that would "enhance" regional and interregional reliability, "address economic efficiency and help states achieve their respective goals." In the paper, "regional" refers to the *NorthernGrid* transmission planning area covering the Pacific Northwest and Intermountain West, where the proposal originated, while "interregional" denotes all three Western U.S. planning areas — CAISO, WestConnect in the Southwest and NorthernGrid — as well as BC Hydro and AESO in Canada.

Beyond the goal of creating an actionable plan that increases grid reliability and efficiency, the effort also would seek to improve "visibility and coordination" of planning across the West and "support" future cost allocation decisions, although the paper makes clear the WTEC "does not intend to formulate or prescribe a cost allocation standard" for projects.

The concept paper does not provide a technical scope for the effort but instead proposes to establish the structure that would define the scope of the effort.

"While this effort is focused on the production of an initial transmission plan, the WTEC envisions that the process could evolve into a durable, long-term function, including periodic updates and refreshed analysis," WPP said in the paper.

Two Committees and a Task Force

The paper proposes the WTEC be organized into two committees and a task force to address technical matters around transmission planning.

At the top would be a Steering Committee "comprised of senior and executive leadership from diverse entities committed to the study effort" and "responsible for resolving and making major decisions to structure the transmission plan."

"While the Steering Committee will make decisions informing the transmission plan, it also carries the responsibility to collaborate with other committees organized to support the effort," the paper states.

The paper proposes the Steering Committee include representatives from NorthernGrid (including BPA and others to be named), CAISO, WestConnect (including WAPA and others), WECC, Canadian province transmission planning, NIPPC, Renewable Northwest, *Interwest Energy Alliance*, PNUCC, PPC and WPP. The committee also would include a "state" representative to be determined after consultation with the region's states.

A Regional Engagement Committee (REC) would consist of representatives from various stakeholder sectors and would "be responsible for providing input and feedback on the approach for the transmission plan, as well as providing input on major decisions informing the transmission plan," according to the paper.

The REC would consist of two members each from: the Steering Committee, federal power marketing agencies, non-federal power marketing organizations, independent power producers, independent transmission developers, public interest groups, ratepayer advocacy organizations, industrial electricity customers, state agencies and tribes. It also would include four members each from investor-owned utilities and consumer-owned utilities.

The paper also proposes a Technical Task Force that would identify transmission study scope and approach, "including but not limited to renewable energy zones, resource expansion, electrification and load data, and scenario development, including extreme event scenarios, phasing of study outcomes and recommendations, data protocols, etc."

The task force would consist of technical staff from Steering Committee members, Pacific Northwest National Laboratory, the Northwest Power and Conservation Council, WPP, and merchant and independent transmission developers. It also would include an independent consultant with expertise in transmission selected by the Steering Committee.

The concept paper also outlines the intent for "periodic communications and public webinars to provide stakeholders from the public with input and feedback opportunities."

WPP is seeking feedback on the proposal and has posed a *series of questions* for stakeholders regarding the proposed participation structure of the WTEC, the composition of its committees and its plans for broader engagement with the region. Comments are due by Oct. 31 and should be sent directly to WPP CEO Sarah Edmonds at sarah.edmonds@westernpowerpool.org. ■

CAISO/West News

CREPC-WIRAB Conference Takes on Western Market Developments

By Robert Mullin

SEATTLE — The Western electricity sector is at a "pivotal point in a lot of different ways," Southern California Edison CEO Steven Powell said last week at a biannual conference of the region's utility regulators and state energy officials.

Powell's take on the sector was shared by many attending the joint fall meeting of the Committee for Regional Electric Power Cooperation and Western Interconnection Regional Advisory Body (CREPC-WIRAB) on the city's waterfront. He was speaking Wednesday on a panel exploring the potential benefits of a more organized electricity market in the West, as well as the issues arising from the competition between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+ for future participants.

The outcome of that contest will set the course for the development of an RTO in the West, or two RTOs split by a seam, many in the sector think.

Powell said his utility "strongly believes that we should all be fighting for and working for getting to a single market in the West."

"That is what is going to drive the most benefits broadly for customers and support the environment the best," he said. He also acknowledged the challenges of getting the entire region on board for one market because of continued concerns about the lack of independence in CAISO's governance.

Powell's view had a lot of sympathizers in the audience, including the handful of utility commissioners who this summer proposed the West-Wide Governance Pathway Initiative, an effort to create an independently governed entity that would underpin a West-wide RTO that pointedly includes California and also contract with CAISO for market services. (See *Stakeholders: Pathway Initiative Offers 'Fresh Look' at Western Market*.)

The single-market perspective found support Friday from participants on a separate panel covering the challenges large energy customers face in procuring energy in a region fractured into 38 balancing authority areas.

Peter Ewen, regulatory strategy lead at Freeport-McMoRan — the largest copper producer in the U.S. — said his company spends $400 million to $500 million a year on electricity to power its Arizona mining operations, equal to about half the outlay of one of the largest utilities in that state.

From left: Arne Olson, E3; WAPA CEO Tracey LeBeau; New Mexico PRC Commissioner Gabriel Aguilera; SCE CEO Steve Powell; and Nevada PUC Commissioner Tammy Cordova | *© RTO Insider LLC*

Freeport-McMoRan operates a division to procure wholesale electricity and, like others who trade power in the West, has seen liquidity dry up in regional bilateral markets over the past five years. Ewen said the company can more cost-effectively obtain power for its operations in South America, where organized markets predominate, than in the Western Interconnection.

The company doesn't have a "particular point of view" on whether CAISO or SPP should be the dominant market operator in the West, Ewen said. "We do think that one balancing authority as opposed to two is the best solution, but two is certainly better than 38.

"We do also see that a full RTO to provides all of kinds of benefits for the challenges that we're seeing. … Stopping with a day-ahead market would be stopping short," he added.

Sharing the panel with Ewen was Jordan Weiszhaar, program manager for data center energy cloud operations at Microsoft. Weiszhaar said much of the talk around organized Western markets is about reliability; she wanted to focus on how a market could encourage economic development.

"What we're realizing is that what drove growth — economic development — over the last 10 years is going to be very different than what is driving the growth over the next 10 years. And how it's going to be different is how it interacts with electricity — and I'm not just talking about [growth in] data centers," she said, pointing to the increasing electrification of transportation and buildings.

In the face of that growth, Weiszhaar said, Microsoft is seeking to expand its data center operations, looking to reliably offer its customers critical services while still meeting its 2030 carbon-free energy target.

"In terms of what our largest challenges are in growing in the West … we are in such a large growth stage right now, we're going wherever we can find capacity available on the grid," Weiszhaar said, what Microsoft calls its "energy-first" expansion strategy.

Finding where that capacity will be in the future is especially difficult in the West's fractured landscape of dozens of balancing authorities, where some planners can under-prepare for load growth.

"From our perspective, we can have fewer

CAISO/West News

organized markets, where we have transparent price signals that show where loads are coming online, but also where the economic development has an opportunity to build … We're going to have a much more efficient system to take advantage of the [economic development] opportunity coming in," she said.

Commissioner Perspectives

Speaking on the markets panel Wednesday, Western Area Power Administration CEO Tracey LeBeau said her federal agency has been exploring RTOs for about 20 years.

"There's several that almost came together and then fell apart at the last moment," she said.

LeBeau said WAPA's eastern customers have differed from those farther west in their desire to jump into a full RTO without taking incremental steps such as participating in something like CAISO's real-time Western Energy Imbalance Market. In 2015, WAPA's Upper Great Plains-East Region joined SPP. In September, the agency issued a decision authorizing its Colorado River Storage Project, Upper Great Plains and Rocky Mountain regions to join SPP's RTO West. (See *WAPA, Basin Electric Commit to SPP's RTO West*.)

"Eight years of experience working in that [RTO] context has been very, very successful," LeBeau said.

She noted that WAPA's Desert Southwest Region (DSW) this year joined the WEIM and has found prices there to be lower than in the region's diminishing bilateral market. The agency continues to study the potential for DSW to join a day-ahead market and RTO in the future. She said some of the main drivers for considering deeper market participation include the need for WAPA's Western customers to hit renewable targets, the retirement of dispatchable generation and the impact of drought on generating resources.

Nevada Public Utilities Commissioner Tammy Cordova pointed out that her state's Senate Bill 448 requires NV Energy to join an RTO by 2030, although the law doesn't make it clear whether EDAM or Markets+ would satisfy the requirement.

"We need to really get engaged really fast and figure out what this means in terms of joining an RTO," she said.

One the biggest challenges for her commission, she said, is to identify what benefits it should be assessing related to joining a day-ahead market or RTO, including those related to rates, reliability and economic development — the last of which could include the potential to sell solar output to other states.

New Mexico Public Regulation Commissioner Gabriel Aguilera brought the market conversation around to the group that utility commissions are charged with protecting: ratepayers.

"The economic, reliability and environmental benefits that we all brag about are only theoretical unless and until we design and implement a market that works for customers," Aguilera said.

"A market needs transparency, proper oversight, competition, level playing field, good management [and] respect for state and federal policies," he continued. "All of these elements create the customer benefits that we're seeing. So in trying to maximize these benefits, as you're making these decisions to design the market, think about ratepayers."

A signatory to the Pathways Initiative proposal, Aguilera warned about the impact to ratepayers of dividing the West into multiple markets, saying, "The broadest possible energy market or RTO also offers New Mexico entities a chance to avoid creating or exacerbating significant seams that would result in new costs and burdens that will be borne for decades to come.

"Seams costs between markets are not a one-time thing but are ongoing indefinitely, incurring costs for utilities and customers and raising policy headaches for states for the foreseeable future," he said. ■

From left: Brian George, Google; Peter Ewen, Freeport-McMoRan; Jordan Weiszhaar, Microsoft; and Washington UTC Commissioner Milt Doumit | © *RTO Insider LLC*

ERCOT News

ERCOT Searching for 3 GW of Winter Capacity

RFP Aimed at Mothballed, Decommissioned Resources

By Tom Kleckner

AUSTIN, Texas — ERCOT surprised the market this week when it said it plans to increase operating reserves by requesting an additional 3,000 MW of capacity to shore up the grid for the upcoming winter.

In a *market notice* issued Oct. 2, the grid operator said its first *monthly resource adequacy assessment* indicates that if it experiences severe weather this winter similar to Winter Storm Elliott last December, it would face an "elevated" risk of entering into an energy emergency alert (EEA) during its projected peak demand. It said that risk, a 19.9% probability, exceeds NERC's acceptable elevated risk threshold of 10%.

ERCOT *said* significant peak load growth since last winter, recent and proposed retirements of dispatchable generation and extreme weather events during the past few winters led to issuing a request for proposals. A list of dispatchable resources that it said "potentially" could be eligible to offer capacity and respond to the RFP included mothballed and seasonally mothballed dispatchable resources (as of Dec. 1) and dispatchable resources that have been decommissioned since December 2020.

Dispatchable resources currently in the interconnection queue that feasibly could be accelerated into commercial operations by Jan. 4 also could be eligible, ERCOT said.

Resources have until Nov. 6 to respond to the RFP. Awards for three-month contracts (December-February) will be announced Nov. 23.

Speaking at the Gulf Coast Power Association's Annual Fall Conference on Oct. 3, ERCOT CEO Pablo Vegas expressed hope that some resources that have indicated they will be mothballed or enter seasonal operations "could stick around for this winter and help out with potentially managing an extreme weather event."

ERCOT CEO Pablo Vegas | © *RTO Insider LLC*

"We want to try to get the risk of an EEA condition down below 10%," Vegas said.

All but four of the 20 resources listed in the market notice would provide no more than 78 MW of winter sustained capability. Three of the four largest — CPS Energy's two coal-fired units at the J.T. Deely plant and Austin Energy's Decker Creek Unit 2 steam generator, each providing 420 to 428 MW of capacity — were decommissioned in 2018 and 2022, respectively.

"We are not considering bringing Deely Units 1 and 2 out of retirement. We made a commitment to our community that those would be retired," CPS spokesperson Dana Sotoodeh said in an email.

An Austin Energy spokesman said there are no plans to bring Decker 2 out of retirement.

The fourth, a 292-MW gas unit outside Corpus Christi, has been approved by ERCOT to indefinitely suspend operations on Nov. 24. (See "ERCOT Evaluating RMR Options," *Texas Public Utility Commission Briefs: Aug. 24, 2023*.)

Stoic Energy's Doug Lewin referred to the units as "zombie power plants" and *said* ERCOT was trying to "bring [them] back to life."

Another market insider, who goes by ERCOT Traders Anon on X (formerly known as Twitter), said ERCOT's action is a capacity auction with two months' lead time. They said this presents a gaming opportunity to marginal units that can "mothball and wait for an out-of-market RFP prior to a peak season."

"What a mess. Nothing good will come from this," they *posted*.

The news caused some GCPA speakers to scramble in revising their discussion points. Dan Jones, a retired ERCOT staffer who still consults with the grid operator, added a new question to the resource adequacy panel that he moderated.

"I just think it was a lot of surprise, really, to see the magnitude of the notice. Everyone else in the hall was pretty surprised," he said.

ERCOT COO Woody Rickerson said the 19.9% risk of emergency conditions was an increase from last year's 7% and "not acceptable."

"It's too high," he said. "That 3,000 MW is enough to reduce the probability of going into EEA."

Asked by an audience member about the probability of getting the RFP's full 3,000 MW, Rickerson said, "I think that's a really big question that's going to get answered in the next couple of months.

"This is also a way of testing what the market is capable of," he added. "What is out there? And what will the cost be? Just because we're asking for up to 3,000 MW doesn't mean that we will have signed contracts. We may not get that much, or it may be too expensive. I think this exercise will help educate us as to what the market is capable of providing." ■

ERCOT is requesting more capacity to meet winter demand during peak hours. | © *RTO Insider LLC*

ERCOT News

Texas High Court to Review Decision on Uri Charges

Supremes Set Hearing over Market Transactions for Jan. 30

By Tom Kleckner

The Texas Supreme Court building | © *RTO Insider LLC*

The Texas Supreme Court has agreed to review a lower court's invalidation of the Public Utility Commission's emergency pricing orders during the deadly 2021 winter storm, potentially placing billions of dollars of transactions at stake.

The state's high court granted the PUC's petition for review Friday and set oral arguments for Jan. 30, 2024 (*23-0231*).

The commission in March asked the court to review the decision, reverse the judgment and either dismiss the case or rule in the PUC's favor. It said the orders it issued expired years ago and therefore cannot be voided, and said the commissioners made "split-second decisions" necessary to help correct a market failure. (See *Texas PUC Appeals Court's Decision on Uri Transactions*.)

The PUC filed its petition shortly after the 3rd Court of Appeals reversed two commission orders to keep the market's wholesale prices at the $9,000/MWh cap during Winter Storm Uri. The court found the commission's actions "entirely" eliminated competition and were contrary to state law. It remanded the case for "further proceedings consistent" with its ruling.

The actions resulted in $16 billion of market transactions that ERCOT's Independent Market Monitor said were incorrectly priced during the 33 hours that followed once the grid operator stopped shedding firm load. The PUC declined to re-price the transactions. (See "Monitor: $16B ERCOT Overcharge," *ERCOT Board Cuts Ties with Magness*.)

Some of the $16 billion balance has since been securitized and some participants have been paying off debts they now might not even owe. Other transactions have been settled outside ERCOT and can't be undone, according to legal expertise.

Luminant Energy, Vistra's generating subsidiary, filed the appeal with the 3rd Court and has been joined by Exelon. They say the commission exceeded its authority in allowing the high prices while the ERCOT grid was trying to find generation after more than 50 GW of resources were knocked offline by the storm.

Calpine, Talen Energy and TexGen Power are among the generators that support the PUC's position. ■

ERCOT News

ERCOT Prepared for Eclipse, Loss of Solar

By Tom Kleckner

ERCOT says it expects normal grid conditions during Saturday's solar eclipse when solar resources, the grid operator's workhorses this past summer during tight afternoon hours, will see their output reduced.

Staff have been looking ahead for months to an *annular solar eclipse* that will cross ERCOT's region between 10:15 a.m. and 1:45 p.m. (CT). They say a maximum coverage of sun ranging from 76% to 90% will affect solar farms, with "clear-sky capability" reduced to at least 13% during the eclipse's peak at 11:50 a.m.

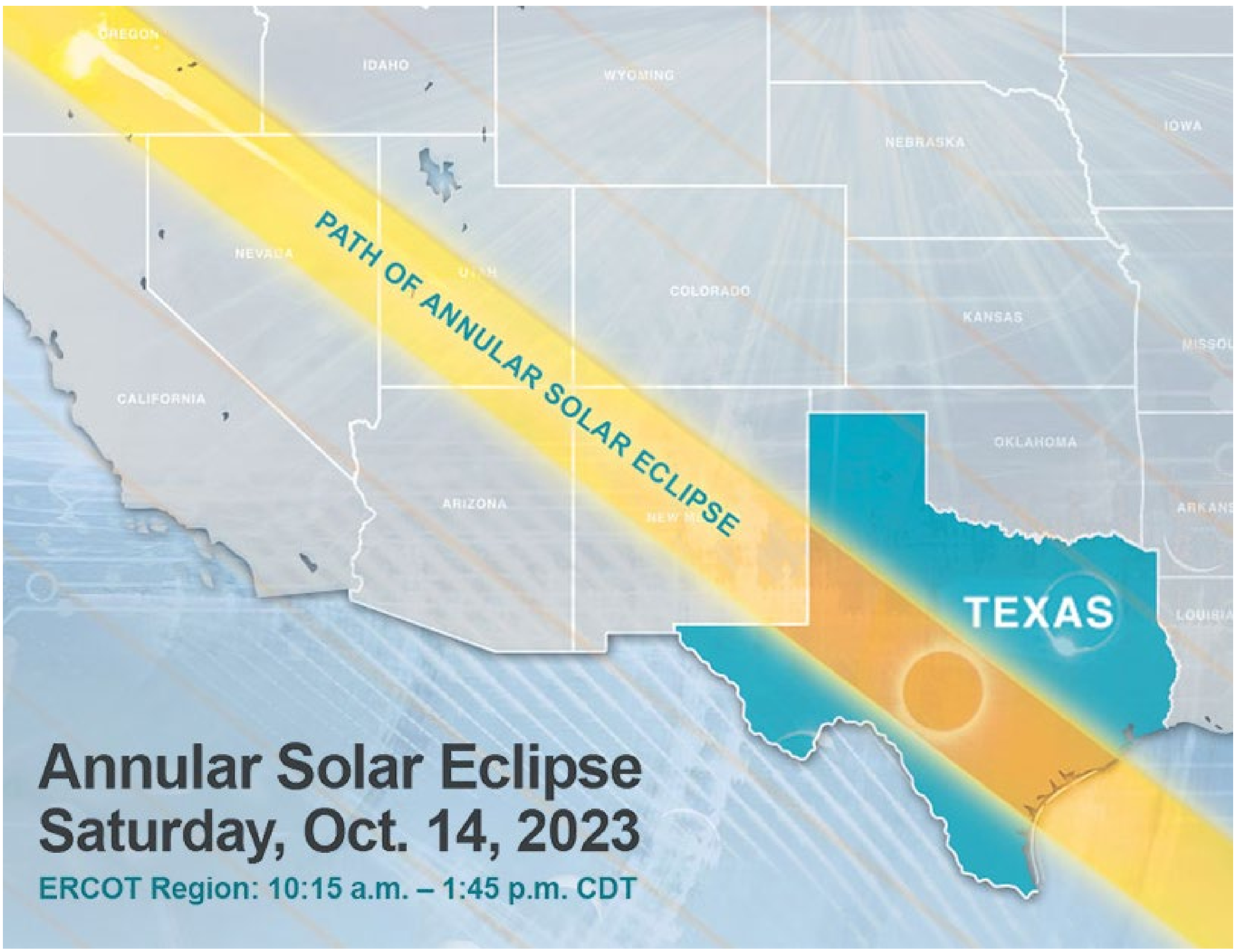
The eclipse will traverse Texas diagonally, from the state's northwest corner to the Gulf Coast. Its path includes San Antonio, Corpus Christi, several smaller cities and swaths of barren land with solar farms.

ERCOT has more than 17 GW of utility-scale installed solar capacity that has accounted for as much as a third of the grid's fuel mix (April) and produced a record 13.7 GW of energy (Sept. 1). It has been credited with filling production gaps during a summer that saw the grid operator set *multiple demand records*. (See *ERCOT Sets New Demand Mark, Will be Short-lived*.)

The ISO has been working with solar forecast vendors to ensure the models account for the eclipse. It said it will prepare the system as necessary to meet the down and up solar ramps and use ancillary services for additional balancing needs.

An annular solar eclipse occurs when the Moon, at or near its farthest point from Earth, passes between our planet and the sun. Because the moon does not cover the sun's entire disc, sunlight surrounds the moon's shadow and creates a "ring of fire" effect.

The event is a prelude to next year's total solar eclipse on April 8. That eclipse will cross over Texas from Mexico and continue into Canada and will be the last eclipse visible in the continental U.S. until 2044. ■



The solar eclipse's path over Texas. | *ERCOT*

ERCOT News

Overheard at GCPA's Annual Fall Conference

Lewin Preaches Benefits of Energy Efficiency, Residential DR

By Tom Kleckner

GCPA attendees await another a panel discussion. | © *RTO Insider LLC*

AUSTIN, Texas — The Gulf Coast Power Association welcomed a record 829 attendees to its 38th annual Fall Conference, smashing the previous high of 766. They gathered Oct. 2-4 for discussions and vignettes on virtual power plants, resource adequacy, new technologies, grid resiliency, energy efficiency and demand response.

Stoic Energy's Doug Lewin keynotes GCPA Fall Conference's second day. | © *RTO Insider LLC*

Stoic Energy's Doug Lewin, introduced as "a man who has commandeered a cultlike following for his insight and passion for clean power and efficient solutions for greater reliability and resiliency" and a "voice of many too nervous to speak," keynoted the conference's second day and its focus on energy efficiency and residential demand response.

That has been Lewin's north star since the disastrous 2021 winter storm that nearly brought down the ERCOT grid. A prolific user of the social network formerly known as Twitter, he has consistently espoused efficiency and residential demand response as answers to ERCOT's difficulties in meeting soaring demand.

Armed with charts, graphs, news clips and data to bolster his point, Lewin asked, "How do we create a highly reliable grid at the least possible cost that will provide abundant and cheap power to as many people as possible?

"Texas has been focused on reliability for a while now, but affordability is also a key part piece of the puzzle," he added. "Texas ranks last in energy burden, with nearly one out of every two Texans struggling to pay their electric bills. This needs attention and hopefully, each of us also agrees the solution must include creating a grid as clean as possible. Balancing reliability, affordability and sustainability ... will create good-paying jobs, profits and wealth creation, tax base and economic growth. We stand to gain a huge share of investment wealth if we can show the world how to build a reliable, affordable and sustainable grid, and especially [if] we can center that grid on customers and strategies that empower them."

The key, Lewin said, is shaving high loads by creating flexible demand where residential consumers can use less electricity when it's scarce and more when it's abundant.

"And they'll get paid for it," he said. "No more [ERCOT] conservation calls, which is nothing but a euphemism for uncompensated demand response."

Three-month-old Sloan Margaret Bunch, daughter of Jupiter Power's Caitlin Smith and EDF Trading's Robert Bunch, takes in her first GCPA conference. | © *RTO Insider LLC*

Lewin had an ally in Octopus Energy CEO Mike Lee. His electric retailer has more than 5 million customers in nine countries and says they can access affordable power during the transition to clean energy.

"As a load-serving entity, my ERCOT bill reflects when people use power, so we need to really shift away from thinking about megawatts," he said. "We need to really think about customers. We have the opportunity of a lifetime to consumerize electricity. We should get creative and say how do we take costs out of the system and reward people for doing so. You have to consumerize it. You have to make it approachable."

VPPs No Longer the 'New Kid'

The pre-conference workshop on virtual power plants, "New Kid on the Block: Virtual Power Plants in ERCOT," may have been a misleading title, its keynoter said.

"Distributed energy resources (DERs) that go into this concept of a virtual power plant are already here. It is not actually a new kid on the block. It is one of the oldest forms of how we supply power to ourselves," Arushi Sharma Frank, senior counsel and U.S. energy markets

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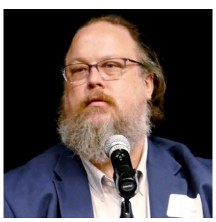
policy lead for Tesla, said.

"The entire grid was distributed before we actually chose to centralize it, so we are actually going kind of back in time and forward [in] time at the same time," she said. "The reason that these things are all showing up in droves without any particular market design or incentive to get them there is because people value losing load at a much higher dollar number than what the grid thinks they value."

Frank vice-chaired an ERCOT pilot project that spent a year studying aggregated DERs and resulted in two VPPs qualified to provide dispatchable power to the state's grid. Eight aggregations (ADERs), totaling 7.2 MW, participated in the pilot project. Two ADERs using Tesla Electric Powerwall storage systems have completed required testing and could provide energy and ancillary services through the third quarter. (See *Texas Public Utility Commission Briefs: Aug. 24, 2023*.)



Eric Goff, Goff Policy | © RTO Insider LLC

As a consultant experienced with the "labyrinth of ERCOT systems," Eric Goff was asked by Texas Public Utility Commissioner Will McAdams about the project's operability.

"The fastest way to commercialize something new, the quicker you can actually make it happen," Goff responded.

"There are so many chicken-and-egg problems that having a laboratory to get things starting to commercialize was the fastest path forward. Now, that said, the pilot nomenclature and size can scare away some investment, so the sooner we can move towards permanent rules, the sooner we can get even more investment and even more participants on this program."

Aaron Berndt, Google | © RTO Insider LLC

That may not be easy. Aaron Berndt, head of energy industry partnerships for Google, said the main barrier to entry in ERCOT's competitive market is the competitive market.

"It really is as simple as either [a] state or the utility saying, 'We have got to come up with ways to fill this gap,' and looking at my list of options to get there. If they're in a state where it's in their best interest to drive energy efficiency and demand response, they can just pile it up into big numbers to scale their program," he said. "You could be scaling Texas energy efficiency programs and just make it easier for retailers to leverage the energy efficiency incentives and stats and use those to enroll them into their demand response program. Then they definitely have the ability to dispatch in a competitive market."

McAdams offered his own counterpart: "$5,000 a is a hell of an incentive," he said, referencing ERCOT's systemwide cap price of $5,000/MWh during scarce operating conditions. "That's every reason in the world where a consumer that has the means and capability and wherewithal, or even an apartment building, that wants to install the capability to avail themselves of this market.

"This is actually providing them a healthy return on investment. I want to get us past the stage where there are all these assertions that we were going to Californiaize the ADERs. We are all in this together ... if we can solve the question of how to pay for system upgrades equitably as a systemwide cost, that goes hand in glove with this conversation about bringing more and more of these capabilities to market."

MISO's John Bear (left), ERCOT's Pablo Vegas discuss the challenges their grids face. | © RTO Insider LLC

Vegas Gives ERCOT an 'A' This Summer

Oncor Energy's Brian Lloyd again displayed his off-beat skills in moderating panels when he opened a conversation with ERCOT CEO Pablo Vegas and MISO CEO John Bear by asking, "So, how was your summer?"

"It was a mix of ups and downs," Vegas said, acknowledging 10 peak-demand records, multiple voluntary conservation calls, and one energy emergency alert. "Overall, I'm really thankful for the way the summer turned out. It was a great way to learn the capabilities of the organization. I am optimistic looking ahead, that summer should hopefully get a little bit easier."

"I was asked a couple times what kind of grade I would give the performance," he added. "I said, 'Probably an A,' and they're like, 'An A? How can you give an A with conservation calls and emergency conditions?' I would say, 'When you're tested as hard as we were this summer and you pass it, you've got to give it an A.'"

Later turning to Bear, Lloyd asked, "Got any plans for the winter?"

Bear responded that he wouldn't be hosting a holiday party, as he did last year for about 100 people on Christmas Eve. He said he spent the party sequestered in his study as Winter Storm Elliott swept through the Midwest.

"We talk a lot about summers, but the summer is a lot easier than the winter now, for all kinds of reasons and challenges we're getting into as we get under our reserve margins," Bear said. "So, how ... we figure out the balance between the summer and the winter from the transmission and generation standpoint is going to be really important.

"We're talking a lot about electrification like that's the miracle that happens in 2030, right? There may be some slope in that curve, right?

ERCOT News

There's a lot of manufacturing and offshoring and things like that going on that we hear about, but where are the assets that are going to provide that energy that businesses need?"

Vegas said the winter season is a "growing risk" for ERCOT, despite its status as a summer-peaking grid, but that the grid operator is taking steps to improve reliability.

"The winter peak is growing and getting closer to the summer peaks as there's more electrification or conversion from gas to electric heating. Since Winter Storm Uri [in 2021], the whole mindset around the winter has really changed in Texas," he said. "The weatherization program is fantastic ... It has been effective, and it was proven to help significantly during Winter Storm Elliott. We have to prioritize where we're investing our resources so that we can partner with the generator community and work together to make sure the resources are going to be reliable."

State Rep Offers Advice

Texas state Rep. Todd Hunter (R), chair of the powerful State Affairs Committee, complimented the state's electric sector for its response to the 2021 winter storm. Or "Snowcane Uri," as he refers to the deadly event that sent temperatures below freezing in all 254 Texas counties.

"That's rare. We can point the finger, blame everybody. What came out of it? Some new, developing legislation and communication," he said.

Much of that legislation came through Hunter's committee this year. He encouraged the audience to stop by his office and visit or keep him updated on the latest developments in the sector.

Citing one of the state's transmission and distribution utilities, Hunter said, "They send me all sorts of texts, which is important for me to know. I'm talking to legislators and I'm talking to other people, so we have a flow of information. Legislators rely on me because that's how I roll. When I know ya, I hear ya."

Kim Casey, GCPA | *© RTO Insider LLC*

Hunter, who prefers to wear only black and speaks in a country drawl, implored his audience to stay engaged with state lawmakers.

"The more you talk to us, the more we can help you. Most people don't know what you do. They don't know what a megawatt is. It sounds like a new burger from Whataburger," he said. "We need power, water and labor. The economy is evolving and growing. We need laws that make sense."

He pointed to the *Harbor Bridge Project* in his hometown, Corpus Christi — which he managed to mention 14 times — as a sign of Texas' booming economy. The new bridge will enable more LNG exports from the city's harbor. When complete, it will also be the tallest structure in South Texas and the longest cable stay bridge in the US.

"When you see this area, it's like the unveiling of a portrait," Hunter said. "Giant demand is coming. Whether you're hydrogen or batteries, we already have stack-ups of different businesses coming into the area. That's happening across Texas. Electricity is big."

GCPA's Casey to Retire

Saying he was both "proud and sad," MD Energy Consulting's Mark Dreyfus and the GCPA's board president told attendees that Kim Casey has notified the directors she intends to retire next year.

"She entered this position with a passion for GCPA and she will depart us with that passion intact. I think that's the best possible outcome for all of us," Dreyfus said. As Casey stood uncomfortably next to him, he said, "Kim will be with us until June 1, so there will be plenty of time to honor and further embarrass her."

"I've been coming to GCPA since 1996. I've not missed one single conference since then, so it's been a pleasure to be part of this and to bring all of you together and it's meant a lot to me," Casey said after receiving a standing ovation. "Thank you to the board for your support and thanks to all of you."

Casey was selected as GCPA's fourth executive director in 2019, bringing more than 30 years of industry experience with her. Under her leadership, the organization survived the COVID-19 pandemic and now has more members than ever in its 40-year history.

Texas Rep. Todd Hunter | *© RTO Insider LLC*

Dreyfus said the board will conduct an open hiring process to find Casey's replacement, with applications accepted through Nov. 15. The organization hopes to announce her successor during its annual spring conference, he said.

"We know that there are many talented participants in GCPA who have a passion for this organization and a great Rolodex, who may be interested in taking a different role," Dreyfus said.

Octopus Energy's Lee Honored

The GCPA honored Octopus Energy's Lee with its annual emPOWERing Young Professionals award, which recognizes industry individuals under 40 years old who provide leadership and contribute to the success of their employer, the power market and the development of other industry professionals.

Lee has worked on some of the earliest energy storage projects and spent more than a decade in the renewables space. A Harvard graduate, he launched Evolve Energy, an energy retailer that focused on real-time index pricing paired with load-shaping automation software and later was acquired by Octopus, now valued at $5 billion. GCPA cited his use of technology to create "demand-centric solutions" for a more resilient grid.

"I would encourage everyone to think that this is not just an empowering young professional award, but also, as an industry, how do we empower disruptors?" Lee said. "We can continue doing what we're doing and make things more expensive and what I think is probably less reliable, or we could do something new. We have incumbents who have established business models and the status quo. But we have disruptors that can do stuff faster, better and cheaper nipping at the heels. So how do we as an industry empower the disruptors?" ■

ISO-NE News

Northeast Stakeholders Push Transmission Planning, Siting Reform

By Jon Lamson

BOSTON — The clean energy transition will require an all-out push on transmission planning and siting reform, government officials and energy experts told stakeholders on Friday, outlining some of the major challenges and opportunities of the region's energy transition.

Several speakers at Raab Associates' New England Electricity Restructuring Roundtable emphasized the importance of interregional and intraregional transmission planning to ensure the grid can handle increased amounts of variable clean energy and higher demand from electrification.

"Transmission planning is vital if we are going to deliver the clean energy transition," said Mike Calviou, senior vice president for National Grid.

Calviou spoke about his experience working for National Grid in the United Kingdom, which has successfully deployed nearly 14 GW of offshore wind operational capacity, compared to just 48 MW in the U.S. He said the U.K. now is facing congestion issues on the transmission system, hurting both rates and the further deployment of clean energy.

To avoid escalating congestion costs in New England as offshore wind capacity increases, Calviou said the region should focus on anticipatory investment and coordinated planning, instead of the current just-in-time approach.

Maria Robinson, director of the U.S. Department of Energy Grid Deployment Office, outlined some of the federal funding opportunities available for transmissions projects, including the $10.5 billion Grid Resilience and Innovation Partnerships Program and the $2.5 billion Transmission Facilitation Program.

Robinson noted, however, that "throwing money at the problem is not necessarily the way to solve these issues around particular backlogs on the transmission system" and called for a targeted approach rather than blunt force.

She highlighted the office's work on National Interest Electric Transmission Corridors, which can increase funding opportunities and streamline the permitting process within designated corridors.

"When it comes to corridors, we're taking a very different approach than the Obama administration," Robinson said, noting that the approach of the Obama administration focused on designating "large swaths of land" as corridors. She said the current approach is more targeted, relying on developers and utilities to indicate exactly where corridors would be helpful.

From left: Robert Ethier, ISO-NE; Clarke Bruno, Anbaric; Mike Calviou, National Grid; Maine PUC Chair Philip Bartlett; and moderator Janet Gail Besser | *© RTO Insider LLC*

"I think it will be both more legally defensible as well as useful to actually get some of these designated," Robinson said.

Clarke Bruno, CEO of the transmission developer Anbaric, touted the potential benefits of an offshore grid to minimize the onshore impacts of deploying offshore wind at scale. (See *Brattle Study Highlights Benefits of Offshore Grid*.)

An ocean grid would be "costly, but less costly than the alternatives," Bruno said.

Permitting and Siting Reform

Government officials from New York and Massachusetts also discussed permitting and siting reform, a topic which has been gaining steam in the commonwealth.

Earlier in the week prior to the conference, Gov. Maura Healey (D) signed an executive order creating a state Commission on Clean Energy Infrastructure Siting and Permitting to make recommendations on permitting and siting reform (see *Massachusetts Announces Permitting And Siting Reform Commission*), while top legislators have indicated the topic is a key priority in the current legislative session. (See *Checking in on Clean Energy at the Mass. Legislature.*)

Houtan Moaveni, executive director of the New York Office of Renewable Energy Siting (ORES), spoke about some of New York's recent successes in expediting the development of clean energy. ORES was created by the legislature in 2020, consolidating the state's siting and environmental review processes for large clean energy infrastructure.

Moaveni said the office has helped usher in the "most rapid pace of renewable energy project approvals in the state's history." He emphasized the importance of the preapplication process, creating clear guidelines for project developers and engaging with impacted communities early in the process.

"Building local support for these projects is just as important as getting regulatory approvals," Moaveni said, adding that he has spent much of his time traveling to meet with communities to understand their needs and ensure local benefits — including discounted electric rates.

"It is possible to streamline and expedite the permitting process for generating facilities without undermining communities and environmental protections," Moaveni said.

Continued on page 19

ISO-NE News

NEPOOL Participants Committee Briefs

Energy market value was up $14 million in September compared to August as natural gas prices increased by 18%, ISO-NE COO Vamsi Chadalavada *told* the NEPOOL Participants Committee (PC) on Thursday. Market value remained low relative to 2022 and was down $368 million from September 2022.

Between 5 and 6 p.m. Sept. 7, the system hit its highest peak load so far this year, at about 24,000 MW. No emergency procedures were triggered by the event.

Annual Work Plan

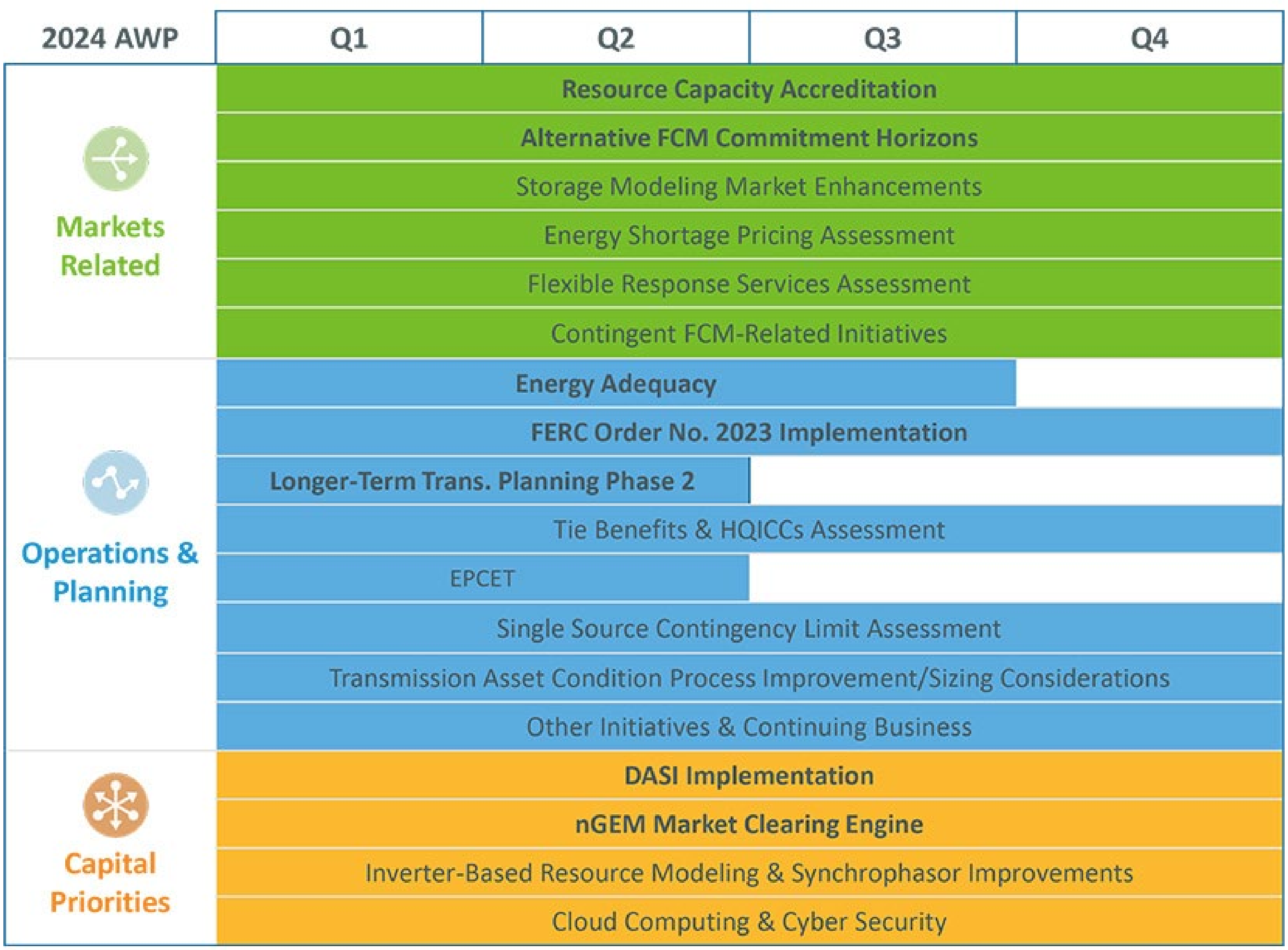
Chadalavada also detailed ISO-NE's 2024 *annual work plan*, outlining some of their major initiatives for the coming year.

He said the RTO's "anchor projects" for the year will be:

- Resource capacity accreditation in the Forward Capacity Market (FCM). (See *ISO-NE Lays out Proposal for Measuring Gas Plants' Winter Limitations* and *ISO-NE Recommends Delaying FCA 19.*)
- Considering changing the FCM to a prompt and/or seasonal construct. (See *Discussion Continues on ISO-NE Capacity Market Changes.*)
- Establishing an energy adequacy threshold through the extreme weather reliability modeling process, now named the Probabilistic Energy Adequacy Tool. (See *ISO-NE Sees Little Shortfall Risk for 2032.*)
- Implementing compliance with FERC Order No. 2023. (See *ISO-NE Details Proposed Order 2023 Compliance.*)
- Changing the tariff to allow more transmission investments made in response to long-term transmission studies.
- Implementing the Day-Ahead Ancillary Services Initiative. (See *NEPOOL Approves ISO-NE DASI Proposal.*)
- Developing a real-time market clearing engine to support an "exponentially complex system."

Concerning the changes for transmission investments, Chadalavada said the process will work to allow for more public policy investments that anticipate load growth and resource development.

"The process would enable conversion of longer-term public policy transmission studies, like the 2050 Transmission Study Solutions, into developable projects," Chadalavada said. He added that stakeholder discussions are expected to begin in the fourth quarter of this year, with a potential FERC filing at some point in the first half of 2024.



ISO-NE 2024 annual work plan | *ISO-NE*

ISO-NE News

New Gas Reliability Study

ISO-NE said the Northeast Power Coordinating Council is proposing a Northeast gas reliability study, which will focus on the ability of the gas network to support the grid. The study will look at the dynamic response of the gas system, including whether the system will be able to support the ramping that will be needed in the future.

"In a future grid, the electricity supply and demand will be much more dynamic, and the study is expected to look at how the gas system reacts to that variability coming from the electric system," a spokesperson for ISO-NE told *RTO Insider* in an email.

ISO-NE CEO Gordon van Welie told the PC that NYISO and the Northeast Gas Association likely will be involved, along with Richard Levitan of Levitan & Associates.

The study will model the loss of certain resource types, as well as the performance of the gas system under extreme weather events, van Welie said.

ISO-NE Budget Passes

The committee voted to support ISO-NE's proposed 2024 operating budget and capital budget, as well as the 2024 NESCOE budget.

ISO-NE has requested a 21.5% increase in the overall budget for the coming year, which the RTO has said will help prepare for the energy transition and retain the workforce. (See *ISO-NE Proposes 21.5% Budget Increase for 2024.)*

The *budget* includes a placeholder for a position focused on environmental policy and community engagement, following the requests from all non-New Hampshire New England states for an executive-level environmental justice position. (See *States Call for an Executive-level EJ Position at ISO-NE*.)

"A successful clean energy transition cannot happen without community engagement and a meaningful role for EJ communities in helping to shape decisions that impact wholesale power and transmission rates and affect how the benefits and burdens of our electric system are apportioned," the states wrote in their request for the position.

Donald Kreis, New Hampshire's consumer advocate, declined to sign the request. In a *letter* to the editor of the Keene Sentinel, Kreis wrote, "the money would be better spent on a position or two that would help the region's ratepayer advocates rein in runaway spending on transmission projects … and blunt the eternal efforts by generation owners to jigger the ISO New England wholesale market rules to enrich electricity magnates, unfairly, at ratepayer expense."

NEPOOL Requests Extra Time for Order 2023

On Monday prior to the meeting, NEPOOL requested a 45-day extension on FERC Order 2023 to allow for more stakeholder input (*RM22-14*).

"With compliance filings due on December 5, 2023, there is insufficient time for proposed revisions to be adequately presented by ISO-NE, fully reviewed and discussed by the Transmission Committee, and voted on by the NEPOOL Participants Committee," NEPOOL wrote. "If the commission does not grant the requested extension, ISO-NE and the commission will lose the benefit of informed discussion through a complete stakeholder process and the opportunity to refine the compliance package before the filing deadline." ■

—Jon Lamson

Northeast Stakeholders Push Transmission Planning, Siting Reform

Continued from page 17

Elizabeth Mahony, commissioner at the Massachusetts Department of Energy Resources, said the newly created permitting and siting commission has "a lot of work to do."

"Maybe we can take a couple of pages from New York's playbook — if it's a good idea, we'll steal it," Mahony said in response to Moaveni's presentation.

Mahony doubled down on the state's commitment to renewable energy development, singling out solar and offshore wind as key areas of growth. She highlighted a DOER *report* released in July on the potential for solar development that mapped solar potential across the entire state. The analysis found the state has the potential for about 50 GW of highly rated solar capacity.

"We can be strategic about where we deploy solar and how we deploy it," Mahony said. "We think that this information … is really a tool that we can use, that municipalities that are facing a lot of permitting issues can use, and certainly that our utilities should be using as they are planning their grid upgrades." ■

From left: Houtan Moaveni, New York Office of Renewable Energy Siting; Elizabeth Mahony, Massachusetts Department of Energy Resources; and moderator Janet Gail Besser | © *RTO Insider LLC*

MISO News

MISO Defends Fleet Predictions over Monitor's Skepticism

MISO, Monitor Differ by 9 GW

By Amanda Durish Cook

Doubts continue to swirl around which version of MISO's future fleet mix is appropriate for long-range transmission planning: the RTO's or the Independent Market Monitor's.

MISO pledged additional examinations of its fleet prediction during a stakeholder teleconference Oct. 2, but that did little to quell reservations on either side of the debate.

Monitor David Patton said he continues to have misgivings about MISO's 20-year fleet assumption that's dominated by nearly 250 GW in anticipated wind and solar additions alongside 53 GW in gas and other flexible generation and 31 GW of standalone battery storage.

MISO is using that fleet assumption to plan the second portfolio of its continuing long-range transmission plan (LRTP). The RTO says recent studies are showing its estimate of the future fleet holds up well and should be used in the multibillion-dollar portfolio.

Now that it has had time to conduct several tests, MISO says it has determined that its middle-of-the-road, 20-year planning future, referred to as Future 2A, "is most aligned with an optimized, least-cost expansion that meets member goals." Director of Economic and Policy Planning Christina Drake said MISO continues to strive to "make sure we have a least-regrets portfolio."

Patton, however, countered, "We continue to believe Future 2A is just not a reasonable basis for planning."

Future 2A underwent an update last year to include members' more aggressive decarbonization goals. Senior Director of Transmission Planning Laura Rauch said MISO will conduct more sensitivities for 2A based on different variables. The RTO is planning a new sensitivity based around hypothetically reduced incentives from the Inflation Reduction Act to see if its projected resource expansion changes meaningfully.

"We'll continue to look for answers, but quite frankly, the answers that we get might not be the ones you're looking for," MISO Vice President of System Planning Aubrey Johnson told stakeholders.

MISO planners are prepared for contentious LRTP workshops, he said. "There's a lot at risk.

Laura Rauch, MISO | © *RTO Insider LLC*

There's a lot at stake. And we don't take these meetings lightly."

Drake said there have been many questions over how MISO arrived at its future fleet assumptions. She said MISO's envisioned resource mix is "rooted in the reality of member plans" and that the LRTP is developed to optimize the delivery of members' decarbonized future fleet. She also said MISO developed the second future over 18 months of stakeholder engagement.

Customized Energy Solutions' David Sapper said numerous stakeholder meetings are not a "proxy" for the actual vetting of the future resource mix used for planning.

MISO: Monitor's Fleet Vision More Expensive

MISO said it tested both the Monitor's ask that it study more natural gas and battery storage resources and a scenario in which capacity accreditation is drastically reduced. It said both comparisons showed that its own version of the future resource mix under 2A represents a "least-cost expansion while considering state and member goals and resource economics."

The RTO found wildly different fleet predictions between its version, the Monitor's and the low accreditation future. It expects the total installed capacity under 2A to reach 471 GW by 2042 and cost $234 billion. It said if it introduced more gas resources and battery storage in place of renewable generation — as the Monitor recommended — costs would climb to $319 billion for 462 GW of capacity in the same time frame.

According to MISO, the Monitor's version of the resource mix would include 103 GW of hybrid renewable and storage resources and nearly 96 GW in gas generation, with 83 GW less in wind resources and over 25 GW less in solar generation from the RTO's prediction. Future 2A calls for 67 GW in natural gas and just 10 GW worth of hybrid resources.

In the reduced capacity accreditation scenario, MISO found a $251 billion resource expansion for 521 GW in installed capacity. That scenario returned a drastic spike in standalone battery storage to 103 GW by 2042.

But Patton said the amounts MISO inferred from his recommendations are faulty.

"The math is obviously wrong. ... Your costs are obviously wrong," Patton told MISO planners. "I don't want anyone coming away from this thinking this is correct."

Patton offered to consult with MISO on a joint hypothetical case of his version. He said there's "no way" his would necessitate more than 100 GW of hybrid resources.

Drake said MISO "triple checked" its cost and capacity conclusions under the Monitor's fleet predictions with more gas and battery resources. Rauch said MISO worked with the best information from the Monitor and said she was "frustrated" that it disagreed with the RTO's outcome.

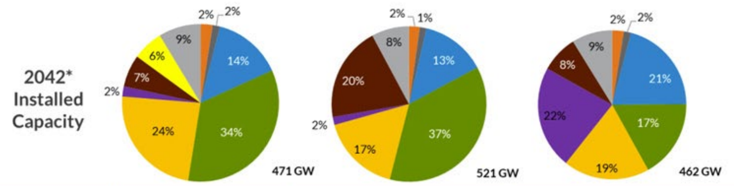
"We're looking at roughly a 9-GW difference between the two scenarios," Rauch said of the overall resource totals.

"There are some more sensitivities that we'll run," Rauch continued. But she said she hasn't so far noticed anything that would cause MISO to rebuild its assumption from the ground up. She said more testing of MISO's fleet assumption will likely "help us solidify and refine what comes out of Future 2A."

WEC Energy Group's Chris Plante said he was "disappointed" MISO didn't work with the Monitor to come up with costs for the high gas and battery model to make certain it was what the IMM had in mind.

Minnesota Power's Tom Butz said MISO's current generation expansion tool used in modeling, the Electric Generation Expansion Analysis System, is no longer "cutting edge" and can't capture all nuances of the future grid. He said MISO filled out the hypothetical resource mix with its own predictions when

MISO News



	Future 2A Expansion	Low-Solar and Wind Accreditation	High Gas & Battery (IMM Proposal as Modeled by MISO)
Total resource cost ($)^	$234B	$251B	$319B
CO_2 reductions from 2005 (%)**	96%	98%	86%
Total Installed Capacity (GW)	**471**	**521**	**462**
Gas	67.1	70.7	95.9
Solar	112	86.8	86.8
Wind	161.7	191.7	78.9
Hybrid	9.8	8.6	103.4
Battery	31.2	103.2	37.2
Energy Adequacy Check***	Yes	No	No

MISO test results of the three kinds of fleet assumptions | *MISO*

it didn't see enough generation in members' plans.

"The bottom line is that this is 100,000 MW beyond what the members have put in there. It's troubling, and it's not indicative of a collaborative process," Butz said of MISO's forecasted 471 GW.

Drake said MISO plans to move to the more sophisticated PLEXUS tool for transmission planning in the coming years.

Patton questioned why the nearly 30 GW in unnamed, flexible resources MISO prescribed won't negate the need for some of the hundreds of gigawatts of renewable energy it is also expecting. He said MISO can't claim it's planning the most cost-effective portfolio if it's not siting more battery storage, especially at constrained transmission points.

"It's not that we lack for capacity. There's sufficient capacity," MISO's Johnson said. Rather, he said, the RTO aimed for a fleet assumption that will furnish energy adequacy across all hours, even in the riskier dawn and dusk periods. MISO foresees a danger of being unable to meet all demand after sunset on hot summer days and during pre-dawn and post-dusk periods on winter days. The RTO said it may find itself depleting battery storage with not enough dispatchable generation to meet hourly demand at those times.

Patton said he thought MISO simply requires capacity under a tougher accreditation to conquer its reliability risks.

Support for MISO's Fleet Prediction

MidAmerican Energy's Dehn Stevens said some members' "myopic view" that the evolution of the system fleet is only going to be driven by capacity needs is "completely off the mark." He said the race to decarbonize will drive the bulk of the resource transition.

"We think this approach is very good," Stevens said of Future 2A.

Otter Tail Power's Stacie Hebert said load growth and resource transformation is imminent for the footprint and that stakeholders need to put more faith in MISO's expertise in transmission needs.

"It's easy to pick out things that might not look right from our worldview right now," she said. But she said MISO is an industry leader in transmission planning. "Inaction and delay also has a cost, so we really need to be balancing our interest in restudies and restudies against inaction."

"Obviously a lot of the stakeholders expressed frustration today," Sustainable FERC Project attorney Lauren Azar said. She said she thinks MISO is doing "all of the analysis it needs to do."

While she said she respects Patton's opinion on markets, she said he is not a transmission planner and does not specialize in grid planning.

"MISO needs to use its professional judgment about what changes it needs … for the grid in 2042," Azar said. She said the RTO's Environmental sector is already concerned that its planning is not keeping pace with the regional backbone projects it will need to support fleet transformation.

"I think we need to move forward and not let the perfect be the enemy of the good," she said.

IMM Again Expresses Worry for Market Operations

During a mid-September virtual forum hosted by the Gulf Coast Power Association, Patton repeated concerns that MISO's LRTP fleet assumption stands to affect the markets.

The Monitor said that ordinarily, MISO's transmission planning doesn't ring alarm bells, but the enormous amounts of renewable energy coupled with "very little" dispatchable generation mean MISO will try to build a transmission system to absorb the fluctuations of an intermittent fleet.

He said "large, uneconomic" transmission investment can dampen the market's ability to facilitate new generation investment and retirements. It's imperative that MISO make sure lines address actual needs, he said.

"Now, the reason we care about this is because transmission investments, by definition, occur outside the market," Patton said. "They're not being done in response to market signals, and they're not being paid for through market revenue … and that's not necessarily bad. That's a choice that in this country we've made in terms of how we make transmission investments.

"But what is important is the investments be made economically … that we invest in transmission as if we were making them in response to forecasted market signals. Because when we make uneconomic transmission investments, then it will distort the market signals and it will adversely affect the participants in the market, as well as raising costs for transmission customers."

Patton said he envisions "a very different future" by 2040, in which MISO adds 108 GW less in renewable energy than it's expecting. He maintains that reduction would save the RTO about $120 billion in renewable energy costs by 2040. He said if MISO adopted his view of the future, it would result in more accurate transmission planning.

"What we believe is more realistic is that batteries and hybrid renewables, which have batteries on-site, will be developed," Patton said.

He also said he takes issue with MISO modeling and planning for a footprint-wide carbon-reduction target when it doesn't have one. ■

MISO News

MISO Defers Unpopular Capacity Accreditation Filing, Remains Committed to Design

Monitor Emphasizes Need for Marginal Accreditation Despite Environmental Concerns

By Amanda Durish Cook

CARMEL, Ind. — MISO said it will push back a contentious filing for a new, marginal approach to capacity accreditation into early next year.

MISO originally was trying to file for FERC permission for the new accreditation by year's end. But persistent stakeholder opposition means the RTO will wait and hold more public discussions to sell stakeholders on its proposal.

MISO maintains a direct loss-of-load-style accreditation will directly link generators' accreditation to their contribution during risky periods.

The direct loss of load approach is set to replace MISO's current use of unforced capacity values in accreditation and will be based on a combination of individual past performance and a class average performance during risky hours for different types of generation. Most MISO resources will see their capacity values decrease under the new method. (See *MISO Strengthens Resolve on Marginal Capacity Accreditation, Stakeholders Displeased*.)

MISO hopes to use the new accreditation by the 2028/29 planning year.

Speaking during an Oct. 4 Resource Adequacy Subcommittee, MISO's Davey Lopez said MISO now will use an expanded set of hours in the accreditation beyond the loss of load hours MISO's annual study produces. The grid operator also will use all the hours when generation supply comes within 3% of load to base accreditation values on.

Lopez said that even using the expanded set of sample hours, the direct-loss-of-load-expectation accreditation will naturally produce more volatile accredited values year over year. But he also said the accreditation will solve some of the "disconnect" between capacity values and actual generator performance in the system's riskiest periods.

Still, stakeholders continue to push MISO to use even more sample hours in the accreditation process, insisting the 3% margin expansion produces an accreditation that uses too few hours. However, Lopez said MISO will not increase the 3% reserve margin threshold further. He said including hours where MISO comes within 5% or 10% of load would defeat the purpose of what MISO's accreditation is trying to accomplish.

Construction of DTE Energy's natural gas-fired Blue Water Energy Center in 2022 | *DTE Energy*

"You would continue to further deviate from where the risk in the model is. You're effectively approaching [unforced capacity] at that point," Lopez said.

Stakeholders continue to call MISO's class average accreditation values mysterious and said understanding how MISO arrived at them is difficult.

"I don't know how any members will meet their fiduciary responsibility ensuring their customers and their shareholders that they're going to get the value they need," Customized Energy Solutions' David Sapper said.

MidAmerican Energy's Dehn Stevens requested MISO delay its planned implementation beyond 2028. He predicted the "shock of resource planners not being able to get new resources online" would offset accreditation losses and pointed out that regulatory approvals for new generation are lengthy.

MISO Independent Market Monitor David Patton recently said a marginal accreditation style is necessary to reflect the diminishing reliability value of intermittent renewables as more are added to the system. He said MISO could have as much as 30 GW of solar power in its fleet by 2030.

"I recognize that marginal accreditation is extremely unpopular, particularly with the environmental community because it results in lower accreditation for most intermittent renewables. But it also would result in lower accreditation for other types of units," Patton explained at a Gulf Coast Power Association Virtual Forum on Sept 15.

Notably, MISO's gas unit class average accreditation drops from the current 84% accreditation in winter to 70% and from 88% in spring to 72% under the new accreditation. Coal unit class average accreditation also drops similarly in winter and spring.

Patton said as MISO's reliability risk shifts to wintertime in the coming years, MISO could dole out smaller capacity values to gas units in winter to reflect gas pipeline issues and the reliability issues that play out when gas-only units have difficulties securing nonfirm gas.

He said the new accreditation will be applied to all resources in a "non-discriminatory fashion." ■

MISO News

Groups Seek Hybrid Exemption from MISO Ban on Renewables Supplying Ramping

By Amanda Durish Cook


| NextEra Energy

Clean energy groups active in MISO told FERC last week that it should rethink its support of a ban on renewable energy in MISO's ancillary services market because the commission didn't consider hybrid resources when it made its decision.

The Solar Energy Industries Association, American Clean Power Association, Clean Grid Alliance, Natural Resources Defense Council, Fresh Energy and Sierra Club are seeking a limited rehearing of FERC's prohibition on renewable energy furnishing ramping needs (*ER23-1195-001*).

The groups said FERC's authorization of MISO's embargo is faulty because it doesn't explain where hybrid resources — combinations of renewable energy and energy storage — factor into the ban.

FERC this year allowed MISO to exclude renewable resources from providing ramping capability and rejected a challenge from SEIA on the RTO's practice of precluding renewable resources from providing ancillary services in its markets. (See *FERC: MISO Can Ban Intermittent Resources from Providing Ramp* and *FERC Blocks Solar Group's Contest of MISO Ban on Renewable Ancillary Services*.) In both cases, FERC said renewables are almost never the most economic choice to supply operating reserves because they're often trapped behind already binding transmission constraints, rendering their output undeliverable.

But the clean energy groups argued that hybrids, unlike standalone renewable resources, are "fundamentally different" in terms of operations and economics.

"Storage paired with renewable resources can relieve congestion and have flexibility that renewables alone do not possess. Because of these differences, the rationale and evidence that MISO provided in support of its prohibition do not apply to hybrids," they said.

The groups suggested MISO eschew a "blanket prohibition" and, at a minimum, allow hybrid participation in the ancillary services market on a one-year temporary basis with the option to reevaluate. They said MISO used the same open-ended, one-year approach when it allowed intermittent resources into its energy market years ago. They said the same approach "is appropriate to deploy here specifically to hybrids." ■

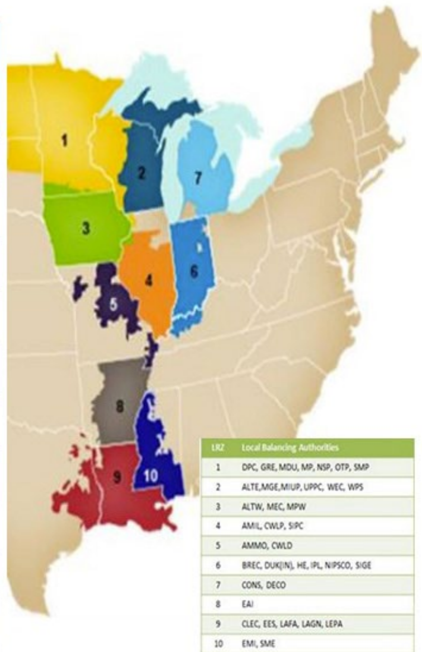
MISO News

MISO 2024 CONE Values Jump on Inflation

MISO has calculated significant increases in its annual cost of new entry (CONE) values for use in its 2024/25 capacity auction.

The average CONE surged to nearly $330/MW-day, ratcheting up from $275/MW-day a year ago and $243/MW-day during the 2022/23 capacity auction. For the first time, all local resource zones surged beyond a $100,000 annual cost to build a single megawatt.

ZONE	PY 2024/25 CONE $*(MW*yr)-1	PY 2023/24 CONE $*(MW*yr)-1	PY 2022/23 CONE $*(MW*yr)-1
LRZ 1	$ 124,541	$ 104,170	$ 91.270
LRZ 2	$ 121,731	$ 102,240	$ 89,490
LRZ 3	$ 117,600	$ 98,590	$ 86,380
LRZ 4	$ 121,434	$ 102,200	$ 90,300
LRZ 5	$ 131,725	$ 109,580	$ 97,190
LRZ 6	$ 120,340	$ 98,590	$ 89,040
LRZ 7	$ 127,135	$ 105,910	$ 93,770
LRZ 8	$ 113,810	$ 94,890	$ 84,310
LRZ 9	$112,804	$ 94,080	$ 83,520
LRZ10	$ 112,263	$ 93,820	$ 83,380



MISO's CONE values by local resource zone over the past three years | *MISO*

MISO said the increase is "mainly due to significant increases in base project capital costs and the weighted average cost of capital, both reflecting actual and expected inflation estimates."

The RTO's CONE represents the cost of building an advanced combustion turbine. It differs by zone to reflect regional differences in construction costs. The values include capital costs, operations and maintenance expenses, property taxes and insurance costs. MISO South typically has lower costs than MISO Midwest.

MISO's Zone 5 in parts of Missouri carries the highest CONE of the zones, at $131,725/MW-year, and experienced the highest year-over-year increase at $22,145/MW-year. Zone 5 usually has the highest CONE.

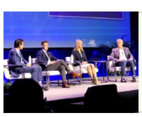
Zone 7, covering Michigan's Lower Peninsula, came in second at $127,135/MW-year.

Mississippi's Zone 10 holds MISO's most inexpensive CONE value at $112,263/MW-year. The zone consistently returns the lowest CONEs.

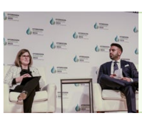
On average, the zones' CONE values increased by $19,931/MW-year. ■

— Amanda Durish Cook

National/Federal news from our other channels



Long-term Optimism Meets Short-term Concern at Offshore WINDPOWER 2023 NetZero Insider



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MISO News

MISO Explains How Aug. Max Gen Event Didn't Trigger Emergency Pricing

Monitor Disagrees with Emergency Pricing for Voluntary Load Reductions

By Amanda Durish Cook

CARMEL, Ind. — MISO last week expounded on why its late August maximum generation emergency wasn't met with prices dictated by its emergency offer floors.

The RTO shared more of the data it collected on the event during its Oct. 3-5 Markets Week. Over those meetings, stakeholders warned the low prices could discourage market participants from voluntary actions to manage dire circumstances.

MISO dipped into its emergency procedures Aug. 24 to activate emergency pricing. Its early morning analysis showed that footprint-wide capacity would fall about 2.8 GW short of demand by the day's peak. (See *MISO: Could Have Employed Wait-and-see Approach for August Emergency*.)

Although MISO enacted its second emergency offer floor at $1,411.74/MWh in this case, it ultimately didn't use the threshold in locational marginal prices, MISO staff said. Aside from a brief spike to about $1,300/MWh around 5:20 p.m. ET, extended locational marginal prices mostly stayed below $200/MWh.

When MISO applies an emergency offer floor, it doesn't automatically mean MISO will set locational marginal prices on emergency pricing. MISO's pricing engine can run optimizations that dodge emergency pricing when emergency resources are readied but ultimately unnecessary to ease system strain.

Some stakeholders said members need more visibility into MISO's price formation to know in real time when emergency pricing is being used. They said emergency resources are expensive to bring online and were forced to take relatively low locational marginal pricing Aug. 24.

On Aug. 24, MISO said it "consistently" imported power from Manitoba Hydro and PJM with a maximum value of nearly 8.5 GW. It also said market participants voluntarily self-scheduled up to 3 GW of load modifying resources in the afternoon peak hours, even though MISO didn't order them.

Travis Stewart, representing the Coalition of Midwest Power Producers, said the nonemergency pricing over Aug. 24 will make market participants think twice about making themselves available in future emergency conditions.

MISO's Tim Aliff describes the Aug. 24 maximum generation emergency at the Oct. 5 Market Subcommittee meeting | *© RTO Insider LLC*

"I think you're hitting at the heart of the conversation we're going to be having: what effect these voluntary actions have and what they should be compensated," MISO's Tim Aliff said during an Oct. 5 Market Subcommittee meeting.

MISO Independent Market Monitor David Patton said he doesn't agree with creating an expectation that voluntary load reductions made ahead of an event should receive emergency pricing. He said MISO should put out its best information available, leaving LMRs to "make their own decision on what prices will be."

"Even when we forecast conditions to be tight, there's a possibility that prices might not go that high," Patton said.

Patton said he'd like to see MISO commit turbines with 30-minute startup times closer to when they're needed, not several hours ahead of time. MISO committed about 25 GW of combustion turbines in its day-ahead market for Aug. 24. In addition, it sent dispatch instructions in real time to another 1.5 GW of small combustion turbines to manage risk.

But Patton did say he respected MISO's decision to cancel generation commitments when it became clear they were unnecessary.

"We haven't seen MISO cancelling commitments at this rate ever. It saved customers about $1.6 million" in revenue sufficiency guarantee payments, Patton said.

MidAmerican Energy Co.'s Dennis Kimm said committing gas units "just in time" in the summer makes sense because gas operators are prepared. However, he said that philosophy shouldn't apply to stressful operations in the winter. He said gas units should be committed ahead of time in the colder months to make sure they can secure fuel supplies.

"We knew this day was not going to be pretty," MISO's John Harmon said at an Oct. 3 Reliability Subcommittee. He said a pre-dawn load check registered higher than forecasted and MISO at the time was expecting an additional 3 GW of generation losses and derates over the day.

By midmorning, however, MISO's in-house meteorologist noticed an isentropic lift weather pattern that had clouds covering major load centers and dampening demand.

A day earlier, MISO's 125 GW of actual peak demand fell short of its 128-GW forecast.

Harmon said MISO dealt with heat-related system stressors for the majority of August.

"This part of August was the fifth heat wave, heat dome, heat spell of the summer," Harmon said, adding that MISO operators until then

MISO News

had prepared for and tracked heat for much of the summer.

MISO merges 10 separate weather forecasts to predict conditions. Harmon said MISO wasn't the only grid operator to encounter load forecasting challenges that day.

"Things changed in a fascinating way that generated a lot of questions," Harmon said. He said accurately predicting cloud cover over load centers in the footprint like Detroit, Minneapolis and New Orleans remains difficult.

"We did what we could to cancel some of those starts due to the drastic change in our reserve margin," Harmon said.

Harmon said conditions improved throughout the day and the emergency declaration lured in more imports, so MISO didn't need to dispatch emergency capacity. Harmon said obligations were met by non-emergency resources in MISO's pricing engine despite the emergency offer floor.

DTE Energy's Mike Samson said MISO may be declaring emergencies too early and might want to wait until later in the operating day when it becomes clear actions are necessary.

Harmon said the other side of that argument is, "if you knew it, why didn't you tell us?" But he said MISO could have more conversations on how best to approach early warnings.

Aliff said MISO has become more proactive over the years as emergency conditions emerge.

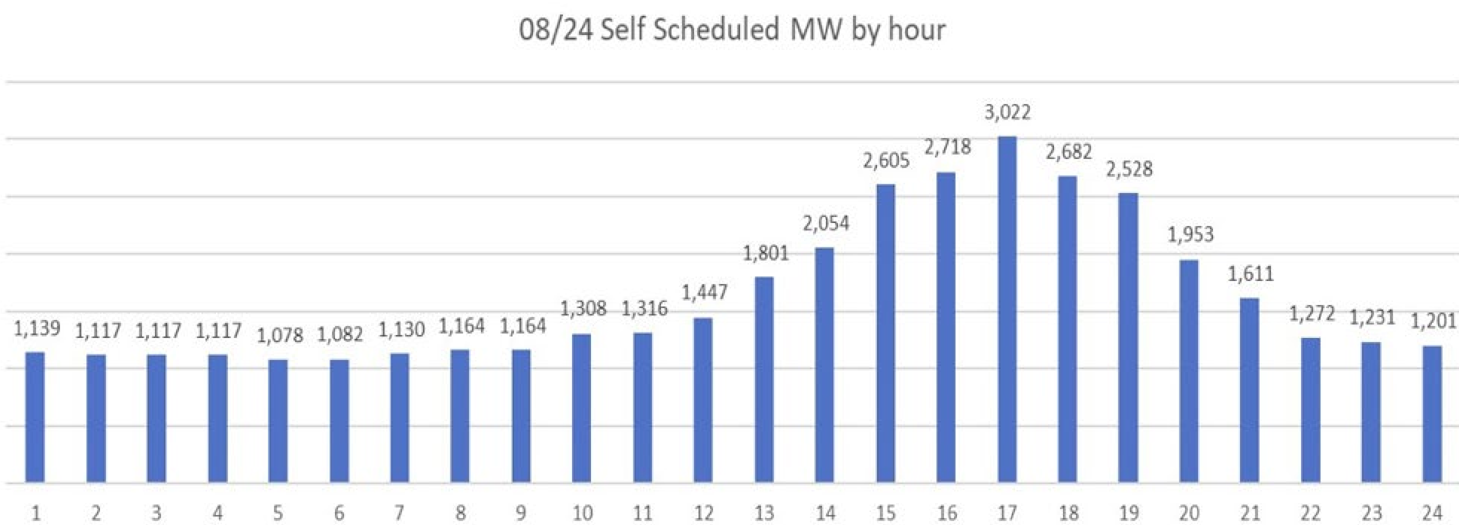
"I've been at MISO 22 years, and I remember the days at MISO where we made declarations minutes before an event," he said.

Aliff said all told, MISO followed the procedures outlined in its tariff, which directs MISO to declare an emergency if it foresees a "significant operating reserve shortage" in its real-time reliability assessment commitment.

Harmon said MISO is investigating how wind forecasts, expected imports and voluntary load reductions can evolve going into an event. He said MISO is looking for ways to improve and takes stakeholders' views seriously after these events.

MISO has taken to commemorating extreme weather emergencies with "flair" pins on lanyards for MISO staff. Harmon predicted the late August event might earn him a new pin in the shape of a thermometer bulb.

Relatedly, MISO continues working on what it deems its "uncertainty management" project to better quantify system unknowns. As part of that, MISO is building a new risk prediction model that will allow MISO to use a dynamic reserve requirement based on a daily risk profile. ■



Market participants' amount of self-scheduled load-modifying resources Aug. 24 | *MISO*

NYSERDA Can't Meet Deadline to Design New REC Plan

Agency Wants Another Year for Complex Tier 4 Planning Process

By John Cropley

The New York State Energy Research and Development Authority needs more time to draw up the renewable energy certificate program for two major transmission projects.

The agency on Wednesday *asked* the state Department of Public Service for a one-year extension of the deadline to create the Tier 4 REC implementation plan.

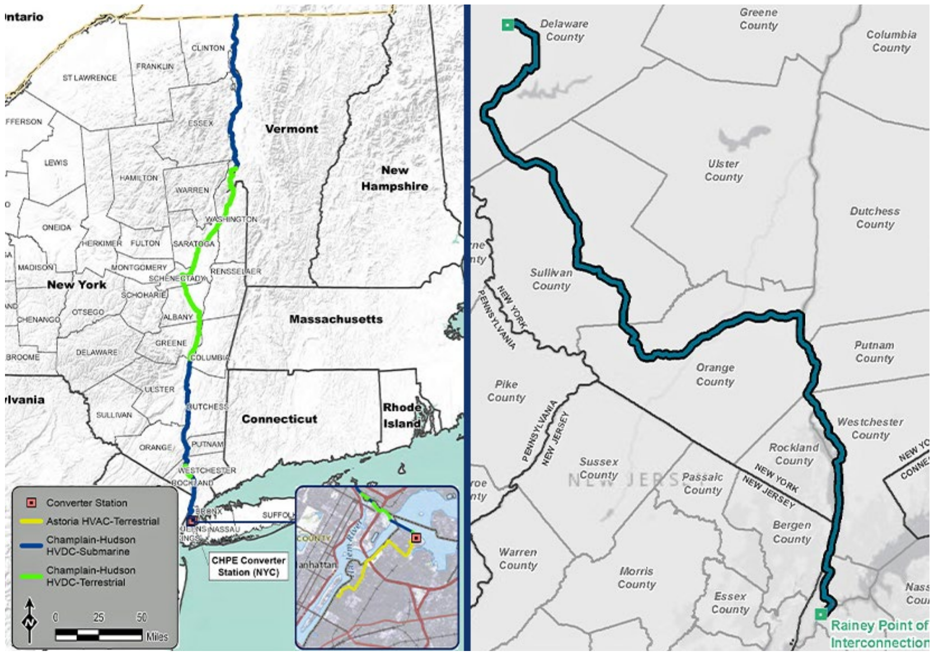
The Public Service Commission on April 14, 2022, *approved* contracts for Champlain Hudson Power Express and Clean Path New York and gave NYSERDA 180 days to draft the implementation plan for RECs for those projects (*15-E-0302*). A few days short of the deadline in October 2022, NYSERDA asked for a one-year extension because of the complexity of the issues, and DPS granted it.

A few days short of the deadline this month, NYSERDA is asking for another 12 months, again citing the complexity of the task before it, the newness of the concepts, the number of factors beyond its direct control and the sheer number of stakeholders collaborating on the effort.

NYSERDA lists seven focus points in its most recent letter, compared with only six last year:

- reviewing Tier 1 and Tier 4 shared resources contract alignment;
- assessing Tier 4 requirements for delivery verification, contract compliance and conformity with existing processes;
- evaluating systematic functionality that may be required in the New York Generation Attribute Tracking System and other enterprise systems for REC accounting, verification and settlement;
- preparing Supplier Greenhouse Gas Baseline accounting standards;
- assessing methods to verify demand response savings;
- establishing voluntary Tier 4 REC sales and settlement processes; and
- monitoring NYISO rulemaking relevant to internal controllable line operations and imported generation.

In its request, NYSERDA points out the two Tier 4 projects are not expected to come online until 2026 and 2027, which allows time for thoughtful and considered planning.



The Champlain Hudson Power Express and Clean Path New York HVDC projects hold New York's two TIER 4 REC contracts. | *Champlain Hudson Power Express / Clean Path New York*

Champlain Hudson is a 340-mile underground/underwater HVDC line under construction that would import electricity from Quebec hydropower plants. Clean Path is an $11 billion suite that includes 1,800 MW of new solar generation, 2,000 MW of new wind power and a 175-mile underground HVDC line.

Both projects are intended to bring emissions-free electricity to New York City, where mandated retirements of fossil-fueled generation are setting up a potential reliability margin deficit as soon as 2025.

NYSERDA's request comes as inflation and interest rate hikes roil the entire financial structure of renewable energy development in New York.

In June, developers with contracts for 4.23 GW of offshore wind nameplate capacity — 97% of the state's offshore pipeline — told the DPS they might not be able to move forward without substantially higher offshore wind RECs. Developers of 91 onshore projects totaling 13.5 GW made the same case to DPS. Collectively the projects are a critical component of New York's statutory goal of achieving 70% renewable power by 2030.

In late August, NYSERDA told the PSC it endorses some form of inflation adjustments as necessary to carry out the clean energy transition in New York.

As this was unfolding, Champlain Hudson and Clean Path made their own requests to the PSC. Clean Path in June wrote that it needed to be included in any inflation adjustments for Tier 1 RECs, as all 23 generation projects in its portfolio hold Tier 1 RECs or are eligible for them.

Champlain Hudson in August wrote that basic issues of fairness dictated it get the same increases granted to any other project, as its costs have increased just like theirs.

The PSC has not ruled on any of these requests yet.

Tier 4 is approaching its third birthday: The PSC created it on Oct. 15, 2020, through an *order* modifying the Clean Energy Standard. NYSERDA's Tier 4 REC solicitation yielded 33 bids from seven sources. Clean Path and Champlain Hudson were ranked first and second, respectively, among the responses.

The two projects are predicted to reduce greenhouse gas emissions by 77 million metric tons over 15 years. The first-year impact on ratepayer bills has been estimated as an increase of 3 to 5.7% per month. ■

NYISO News

FERC Reaffirms NYISO's 17-Year Amortization, Dismisses Protests

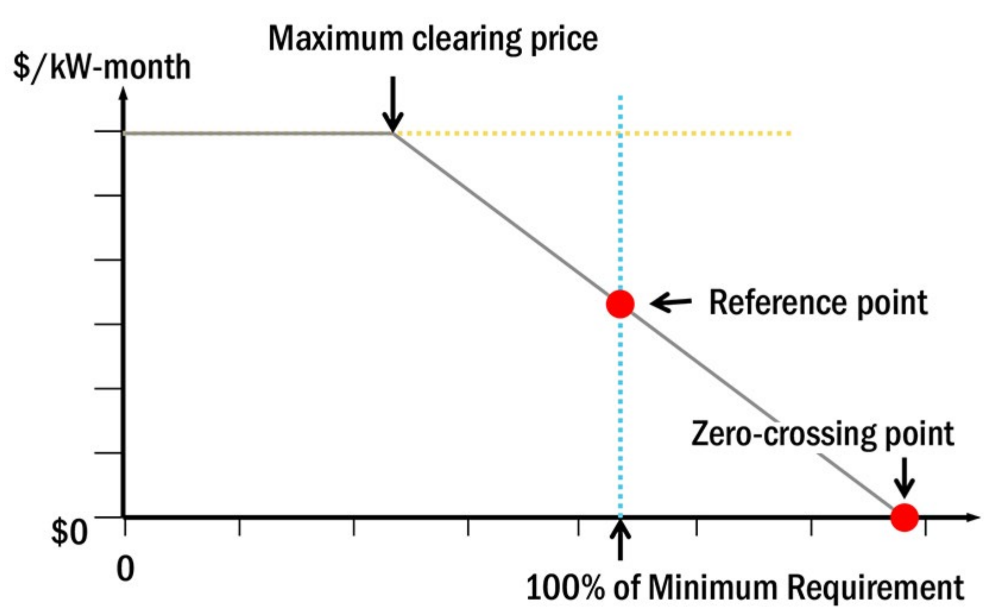
By John Norris

FERC on Wednesday reaffirmed its support for NYISO's 17-year amortization period for demand curves in its installed capacity market, rejecting protests from the New York Public Service Commission and consumer stakeholders (*ER21-502*).

The commission's latest order amends but essentially upholds its May ruling, when the commission reversed course and approved NYISO's proposal to shorten the assumed operational lifetime of a hypothetical natural gas peaking plant from 20 to 17 years. The commission approved the ISO's proposal after the D.C. Circuit Court of Appeals issued a remand, ordering the commission to reconsider its prior rejection. (See *FERC Accepts NYISO's 17-Year Amortization Period Proposal*.)

NYISO's proposal was in response to New York's Climate Leadership and Community Protection Act, which mandates strict net-zero emission goals and makes it more challenging for fossil fuel power plants to operate in the state. NYISO had used a 30-year amortization period until 2014, when the commission approved the 20-year term to reflect the technological, market and environmental risks of investing in the proposed proxy plant.

The PSC and consumer stakeholders argued the 17-year amortization period could increase capacity costs by $400 million over the 22-month period from July 2023 through April 2025. They also said the commission's ruling runs afoul of its previous rulings rejecting the same proposal.



ICAP demand curve slope | *NYISO*

FERC rejected these arguments, saying it provided a "full and rational explanation" for its reversal and emphasized the ISO's compliance filing was in line with its directives.

The order included a dissent from Commissioner Mark C. Christie that reiterates his previous arguments, which contend FERC's decision to accept NYISO's 17-year proposal undermines the commission's original rulings and ignores expert opinions from industry stakeholders. ■

NYISO News

NYISO Unveils New Order 2023 Compliance Proposal at Inaugural IITF

By John Norris

RENSSELAER, N.Y. — NYISO on Oct. 2 *presented* another reformulated proposal to enhance its interconnection study processes and align with the new directives set forth in FERC Order 2023.

During the Interconnection Issues Task Force's first meeting, NYISO said it will adhere to FERC's proposed study format but introduce some ISO-specific variations, such as a two-phase cluster study, a rolling optional pre-application and an altered customer engagement window with a physical infeasibility screening. The IITF was established to investigate, refine and implement these directives.

NYISO argues that its proposal strikes a balance between FERC's guidelines and the unique needs of New York's energy landscape. FERC's directive accommodates such variations, recognizing that each RTO and ISO faces its own set of challenges and policies.

The most significant difference between NYISO's and FERC's proposals lies in the structure of the cluster studies.

Unlike FERC's single cluster study that is followed by individual facility studies, the ISO uses a two-phase approach in which routine interconnection studies, like the system reliability impact study or system upgrade study, would be conducted in the second phase.

A new window would be initiated every 18 months, sticking to the commission's overall timeline but incorporating elements from NYISO's previous interconnection queue changes. There would be a slight overlap between each cluster study window, but the ISO does not expect this to necessitate any rework.

Thinh Nguyen, NYISO senior manager of interconnection projects, explained that the ISO also wants to include several pre-work phases within the study window to "help organize and provide the appropriate information at the start of each phase to developers and" the ISO.

NYISO would transition directly to the new cluster study process, bypassing a yearlong transitional study. The move aims to minimize the transition impacts and allow the next cohort of projects sufficient time to adapt to the new procedures.

Stakeholders at the IITF meeting were generally receptive to NYISO's proposals but urged the ISO to ensure clarity in its revisions to avoid future confusion.

Mark Reeder, representing the Alliance for Clean Energy New York, worried about the window overlap and if conducting project feasibility studies at the end of one window when another starts was the best way to go about things.

Sara Keegan, an attorney with NYISO, responded that conducting these studies later has proved more efficient in other RTO and ISOs interconnection studies and the ISO does not think it would cause any issues.

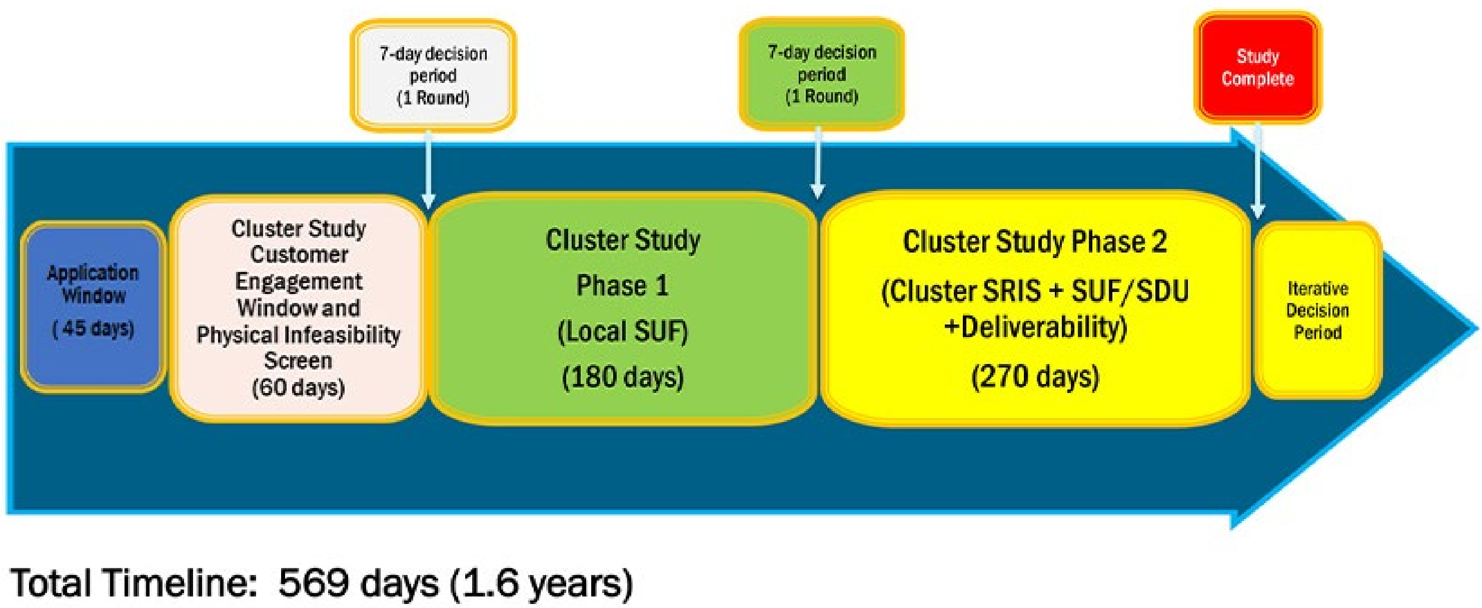
Howard Fromer, who represents Bayonne Energy Center, expressed concern for how Class Year 2021 projects currently seeking interconnection would be affected. NYISO clarified that because these projects finished class year processes, they are now subject to different standards, but it promised further details in the future.

Doreen Saia, an attorney with Greenberg Traurig, inquired about the treatment of new interconnection requests during this transition period, saying the ISO should try and get ahead of this potential issue to avoid "having a whole bunch of requests coming in because [projects] are afraid of missing out."

NYISO staff assured Saia that new requests would continue to be accepted and promised to provide a clearer timetable soon.

NYISO, along with other RTOs, filed Order 2023 compliance extension requests with FERC, but if its request is denied, then it must file its compliance by Dec. 5. (See *NYISO to Ask FERC for Order 2023 Compliance Extension*.)

The IITF will reconvene to discuss the proposal in greater detail Oct. 20. ■



Overview of NYISO's newly proposed cluster study process | *NYISO*

PJM News

PJM Shortlists 3 Scenarios for 2022 RTEP Window 3

RTO Got 72 Proposals from 10 Entities, Combined Some for 2 Scenarios

By Devin Leith-Yessian

PJM last week *presented* a shortlist of three scenarios of transmission upgrades to address needs identified in the 2022 Regional Transmission Expansion Plan (RTEP) Window 3. (See "Update on RTEP Windows," *PJM PC/TEAC Briefs: Aug. 8, 2023.*)

"There is a lot of interest in this particular planning window. ... This is a major expansion of our transmission system," PJM Senior Vice President of State Policy and Member Services Asim Haque said during an Oct. 3 meeting of the Transmission Expansion Advisory Committee (TEAC). "We're facing some serious changes to the electric grid in this area based on increase in the electric demand and retirements of fossil fuel generators."

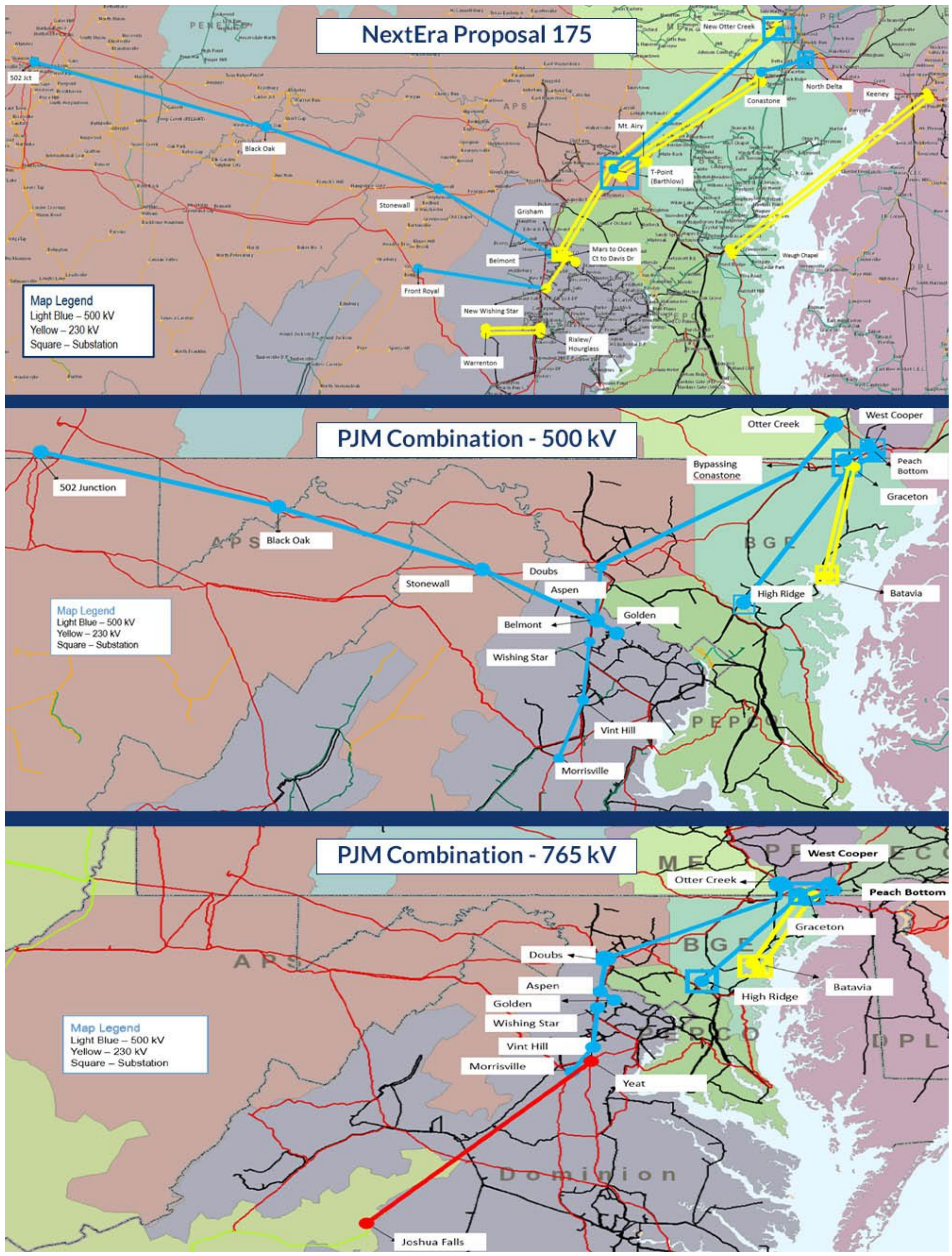
All three scenarios would expand the 500-kV grid, and potentially construct the first 765-kV line in the Dominion region, to meet growing data center load and generation retirements such as the 1,295-MW Brandon Shores plant. PJM Executive Director of System Planning Dave Souder said more information about the potential of a reliability-must-run contract being reached with Talen Energy should be available around the end of the year. (See "Brandon Shores Deactivation to Require $786M in Grid Upgrades," *PJM PC/TEAC Briefs: June 6, 2023.*)

PJM received 72 proposals from 10 entities, portions of which were combined to form two scenarios. Only NextEra's proposal #175 was selected as a shortlisted scenario without PJM modification. PJM's Sami Abdulsalam said the RTO plans to bring one of the shortlisted scenarios to stakeholders for a first read Oct. 31 and to the board for approval in December.

The 765-kV line proposed in one of the two aggregate PJM scenarios would begin at the Joshua Falls substation and run north to the data center alley in Loudoun County, Va.

One of the PJM plans would construct a 765-kV line between the Joshua Falls and Yeat substations, bringing power into Loudoun County from the south. Additional transmission capability would also be constructed to the northeast, tapping into the 500-kV grid at Peach Bottom.

PJM's other scenario focuses on expanding the 500-kV grid by building new lines from northern Virginia out to Peach Bottom to the northeast and the 502 Junction substation to



PJM shortlisted a NextEra and two aggregated proposals to meet transmission needs identified in its 2022 Regional Transmission Expansion Plan (RTEP) Window 3. | *PJM*

the northwest.

Both scenarios include additional 500- and 230-kV lines that would be built in the BGE zone to meet some of the expected need created by the Brandon Shores retirement.

The NextEra scenario would follow a similar 500-kV pathway between the 502 Junction and the data center alley, as well as several 500- and 230-kV lines to the northeast routing through a proposed Barthlow substation and continuing to the Conastone and New Otter Creek facilities.

Two 230-kV lines would be constructed between the Keeney substation on the Delmarva Peninsula, across the Chesapeake Bay and

PJM News

PJM's Sami Abdulsalam presents three shortlisted scenarios for meeting the transmission needs identified in the 2022 Regional Transmission Expansion Plan Window 3 during an Oct. 2 meeting of the Transmission Expansion Advisory Committee. | *© RTO Insider LLC*

connecting to the Waugh Chapel substation in the BGE area.

Abdulsalam said each of the scenarios comes with positives and negatives. The NextEra scenario would avoid modifications to the Doubs substation, which has become the terminus for an increasing number of lines, while the Barthlow substation would have nearly a dozen lines tying into it. The scenario would also require significant acquisition of new rights of way and the component running a line under the Chesapeake could pose voltage concerns in BGE, as well as environmental and permitting concerns.

The 500-kV scenario offers the advantage of avoiding disruption to the Conastone substation and having strong cost containment for the component constructing a line between Doubs and Otter Creek. The 765-kV plan would relax flows in the north with the addition of the higher voltage transmission proposed in the south and would add to the backbone capability in Dominion. Siting, permitting and procuring equipment for a 765-kV line comes with higher risk, but Abdulsalam said the 500-kV components of the scenario could provide short-term relief while the 765-kV is built.

Abdulsalam said the proposals contain commonalities that demonstrate a general understanding that additional transmission capability will be needed to move energy from the east to the west, augmented by transmission either from the south or northwest.

PJM's Nebiat Tesfa said planning staff used a combination of NextEra, Exelon, FirstEnergy and Dominion proposals as a starting point to construct its aggregate proposals, in some cases working with proposing entities to break out individual components to combine with portions of other proposals. Analysis of combining several LS Power, Transource and NextEra proposals found a larger number of violations in the 2028 case.

Of the 72 proposals, 50 involve greenfield development of new lines, while the remainder are upgrades or construction within existing rights of way.

PJM's characterization of the impacts and risks that greenfield proposals carry was disputed by several residents who live in the communities some of the projects would pass through. They argued that expanding rights of way to construct lines paralleling existing infrastructure would have a larger impact than is represented in PJM's analysis and that the extent of the amount of greenfield was underplayed.

The window contains models for both 2027 and 2028, with the primary differences being that the latter includes more deactivations, including Brandon Shores, and adjustments to how resource dispatch is reflected in the analysis. Both the Brandon Shores retirement and the changes to block dispatching came after PJM had released the 2027 case, but before the following year had been finalized. (See "Load Forecast for Northern Virginia Data Centers Continues to Climb," *PJM PC/TEAC Briefs: Jan. 10, 2023*.)

Exelon's Alex Stern encouraged PJM to reach out to both the relevant incumbent transmission owners and state commissions regarding any non-incumbent proposals that include underbuilding on existing lines, particularly if it could cause states to lose jurisdiction. Incumbent TOs are also likely to have more detailed insight into anticipated needs in their region and may have a use for the underbuilding capability they were planning to use in the future.

After an initial assessment of the potential of each of the 72 proposals, PJM created an initial shortlist for more detailed analysis of their cost estimate, cost containment, scheduling, constructability, brownfield and outage coordination risks. The risk assessment also considered permitting, potential environmental issues and public opposition to past projects. ■

PJM News

PJM OC Briefs

Generators Cite Reasons for Low Synch Reserve Response Rate

VALLEY FORGE, Pa. — PJM *presented* feedback it received from synchronized reserve resources that have come up short in their response to reserve deployments since October 2022, when PJM implemented a market overhaul that was followed by a drop in reserve response rates. (See *Synchronized Reserve Pricing Falls in PJM Markets After Overhaul*.)

Resources responding to outreach from PJM and the Independent Market Monitor attributed portions of their shortfall to delayed, insufficient or incorrect action at their market operation centers. Factors included missing an all-call signal; not understanding how to respond to a spin event; and incorrect parameters, such as ramp rate, being reported in Markets Gateway.

Some generation owners said they had been operating under the Intelligent Reserve Deployment (IRD) rules that PJM had proposed, but which were ultimately rejected by FERC in August 2022. The IRD proposal would have included a level of reserves being requested from generators; however, the status quo requires that resources provide their full reserve obligation unless directed to do otherwise.

PJM sought to address the diminished response rate by increasing the synchronized reserve requirement by 30% in May, overriding a Markets and Reliability Committee (MRC) vote that rejected the increase. It also proposed to create the Reserve Certainty Senior Task Force to discuss changes to several components of the reserve market and how it operates. The task force has its first meeting on Oct. 10. (See "PJM Issue Charge on Reserve Certainty Approved," *PJM MRC/MC Briefs: Sept. 20, 2023*.)

The RTO has published an *FAQ* and *guidance* for synchronized reserve resources to improve resource owners' understanding of how the market functions and their obligations during a spin event.

PJM's Melissa Pilong told the OC that close to 100 resources responded to the outreach, accounting for approximately 75% of the shortfall by megawatts over the past year. She said PJM's goal is to find solutions that can allow the reliability requirement to be reduced back to 100% of the single largest contingency.

| © RTO Insider LLC

Stakeholders Endorse Outage Coordination Manual Revisions

The OC endorsed conforming revisions to Manual 38 to codify the outage coordination package the committee approved in June. (See *PJM OC Briefs: June 8, 2023*.)

The package adds coordination between utilities and PJM to identify potential extended outages, evaluate their impact and expand the outage information released by the RTO. The manual language will be considered by the MRC during its Oct. 25 meeting.

A competing proposal from the Monitor, which received 17% support in June, sought to increase transparency about late outages and impacts on transmission congestion.

PJM Proposes Quick Fix for Transmission Cut-in Process

PJM *presented* a quick fix proposal to allow the RTO to delay the end time of a cut-in ticket by one day if information regarding one of the "critical cut-in tasks" has not been supplied and extending the outage is not expected to pose reliability concerns. PJM will coordinate with the transmission owner to obtain the missing information prior to the line being energized.

The quick fix process allowed PJM to bring a problem statement and issue charge concurrently with a proposed solution. The OC is set to vote on the proposal Nov. 2, followed by the MRC on Nov. 15. If approved, the change would be effective upon MRC endorsement.

PJM's Dean Manno told the OC that a one-day delay is being sought as review of the information can be done in that time once it's received.

PJM Presents Recommended Winter Weekly Reserve Target Values

PJM's Patricio Rocha-Garrido *presented* the recommended winter weekly reserve targets (WWRT) values for the 2023/24 winter, which call for a higher level of reserves for each month compared with last winter. The WWRT is used to inform the scheduling of planned outages during the winter to minimize the potential for maintenance to cause a higher loss of load expectation.

The recommended maximum monthly available reserves figure is 28% for December, 30% for January and 25% for February. The values for last winter were 21% for December, 27% for January and 23% for February.

Garrido said this year's analysis included a higher forced outage rate in the historical data

Continued on page 34

PJM MIC Briefs

Multi-schedule Modeling in Market Clearing Engine

VALLEY FORGE, Pa. — The PJM Market Implementation Committee endorsed two proposals intended to include multi-schedule modeling in the market clearing engine (MCE) without causing performance impact because of the large number of additional offers the engine would have to consider. (See "Discussion Continues on Multi-schedule Clearing in The Market Clearing Engine," *PJM MIC Briefs: Sept 6, 2023*.)

PJM's proposal, which would create a formula to select the offer expected to produce the lowest total dispatch cost and forward only that offer to the MCE, received the greatest amount of support and will be considered the main motion before the Markets and Reliability Committee. A joint PJM and GT Power Group proposal was also endorsed by the committee and would select resources' cost-based offers when they fail the three-pivotal-supplier (TPS) market power test and their parameter-limited offers during emergency conditions.

The *problem statement* that PJM brought forward in December 2022 states that each resource schedule entered into the MCE is modeled as a logical resource. When paired with the number of configurations that combined cycle and storage resources can enter schedules for, the introduction of multi-schedule modeling would cause an exponential increase in the number of logical resources the engine would have to process, potentially leading to untenable increases in computational times. All *five proposals* aimed to reduce the number of schedules that are submitted to the MCE prior to the optimization process.

Three proposals from the Independent Market Monitor, including one jointly sponsored with GT Power, failed to receive majority support. During first reads in September, Deputy Monitor Catherine Tyler told the MIC that the proposal's goal was to solve the performance issues that multi-schedule modeling is expected to pose while also improving market power mitigation. She also argued that the PJM proposal could be dispatched on schedules that don't match the most cost-effective fuel and that it would allow generators with market power to raise energy prices by using high markups and to extract uplift using inflexible parameters.

The first Monitor proposal would combine the lowest offer points and most flexible parameters from resources' price- and cost-based offers under certain scenarios; impose offer capping and parameter limits to all resources that fail the TPS test; and apply parameter limits to capacity resources during emergencies. The Monitor's second package would do the same as above but would use the status quo rules for resources with multiple cost-based offers.

The joint Monitor and GT Power proposal would commit resources that fail the TPS test and have multiple offers to operate based on the fuel that the generation owner expects to use in each hour of the day. Tyler said that any generators not submitting the most efficient offer may be considered to be engaging in market manipulation.

PJM's Adam Keech | © RTO Insider LLC

Creation of Fifth CONE Area Endorsed

Stakeholders endorsed a joint *proposal* from PJM, the Monitor and E-Cubed Policy Associates to create a fifth cost of new entry (CONE) area for the Commonwealth Edison region.

The proposal is intended to allow the CONE for the ComEd region to reflect the expected shortened lifespan of the reference resource, a combined cycle unit, under the Illinois Climate and Equitable Jobs Act. (See "Fifth CONE Area Under Consideration," *PJM MRC/MC Briefs: Sept. 20, 2023*.)

PJM's Gary Helm stated that the new CONE value for ComEd will be $201,714/MW-year, compared to $197,800/MW-year in CONE area 3, from which the existing area would be broken out of under the proposal. All other variables, such as labor costs, will remain the same, but they may be revised under the next Quadrennial Review.

E-Cubed had previously sponsored a proposal to create an automated process for adding new CONE areas when local or state factors affect key parameters of the reference resource, such as asset lifespan, or when they may imply a different reference resource than the one PJM has designated.

Capacity Obligations for Forecasted Large Load Adjustments

Stakeholders approved an *issue charge* brought by Dominion Energy and American Electric Power to consider *changes* to how capacity obligations are allocated following a large change in the load in one or a small number of load-serving entities.

Josh Burkholder of AEP said that the capacity obligation accounting for such a change in load is allocated across all entities within the zone, regardless of whether they are under fixed resource requirement (FRR) or Reliability Pricing Model (RPM) rules.

Unlike standard changes in load, the *problem statement* argues that large load customers, such as data centers, tend to be geographically concentrated in one region that can be tied to one or a handful of LSEs. It states that the issue is isolated to forecasted loads, as once they come online, their actual consumption is accounted for in the capacity obligation

PJM News

assigned to the LSE.

The issue charge was revised following a first read at last month's MIC to revise the focus from being on large load additions to adjustments, to reflect that forecast reductions in load can have a similar effect. The scope was also clarified to include the assignment of obligations between RPM and FRR markets as well as individual LSEs. The stakeholder process was also changed to the full consensus-based issue resolution (CBIR) process, instead of the abbreviated CBIR Lite pathway, and the estimated timeline was revised to four months with the goal of having changes that can be implemented in the 2025/26 Base Residual Auction (BRA) if feasible.

Burkholder said the issue charge would not change the settlements process but instead focus on how capacity obligations for identifiable forecast large loads are allocated. Settlements are in-scope only to avoid any unintended consequences.

Calpine's David "Scarp" Scarpignato made the case that the issue extends beyond load changes in regions served by RPM entities resulting in changes to the capacity obligation for FRR resources, saying that a significant change in load within an LSE whose footprint lies in multiple transmission zones can result in that impact bleeding across zones.

PJM Reviews Board of Managers CIFP Letter

PJM Vice President of Market Design and Economics Adam Keech said the RTO is on track to make a FERC filing by the Oct. 13 deadline the Board of Managers set in a letter announcing a slate of capacity market changes resulting from the Critical Issue Fast Path (CIFP) process it initiated in February. (See *PJM Board Releases Outline of Capacity Market Changes*.)

To meet the aim of having changes that can be implemented for the 2025/26 BRA, Keech said FERC approval would be required by early February to leave time for pre-auction activities and for market participants to prepare. Portions of the changes being proposed involve processes that begin toward the start of the pre-auction activities, meaning an order is needed before work can substantively begin.

Keech said two approaches that PJM could take when drafting the filing would be to either ask the commission to delay the auction until an order is released, or to state that the RTO will begin with pre-auction activities under the current rules unless directed to do otherwise.

Any delay to the 2025/26 auction would likely mean changes to the timeline for subsequent auctions as well because of how tightly packed together they are.

PJM is also discussing whether it is best to proceed with a single filing encompassing all of the proposed changes, or to break it into two filings, grouping together changes that staff believe would have to be made as a package. Keech said he believes that changes to performance assessment intervals would have to be linked with the market seller offer cap because there's a connection between the two with the eligibility to receive Capacity Performance bonus payments.

PJM Senior Counsel Chen Lu said staff considered waiving the RTO's right to preclude the commission from conditioning approval of a Federal Power Act Section 205 filing under *NRG Power Marketing v. FERC*, but they determined that not all of the components of the proposed changes are severable.

Keech said the board is currently deliberating the direction and best forum to hold further discussions of issues that are not expected to be resolved through the filing, such as a seasonal capacity market. ■

— Devin Leith-Yessian

PJM OC Briefs

Continued from page 32

owing to inclusion of extreme weather during the 2014 polar vortex and the December 2022 winter storm. PJM had historically not included the polar vortex data in its analysis, but reversed that based on its experience during Winter Storm Elliott.

The WWRT is one of the three values produced through the annual Reserve Requirement Study. The Planning Committee voted on Oct. 3 to endorse PJM's recommended installed reserve margin (IRM) and forecast pool requirement figures, both of which would increase the reserves PJM aims to procure for the 2027/28 delivery year. (See "First Read of 2023 RRS Values," *PJM MRC/MC Briefs: Sept. 20, 2023*.)

Quick Fix for Public Conservation Request Guidelines Proposed

PJM *proposed* changes to its public notifications seeking reductions in electric consumption during emergency conditions to specify that the request is being made of all consumers, not just residential load, and to aim to better integrate the notification process into other emergency procedures. Additional ways that consumers can conserve energy are also included in the proposed language.

The proposed manual revisions also detail PJM's reporting requirements to the Department of Energy, NERC and RF or SERC when a conservation request is made.

The revisions will be considered by the OC and MRC during their November meetings.

Periodic Review Revisions to Several Manuals Discussed

- Stakeholders endorsed *revisions* to Manual 3A intended to clarify PJM's quarterly data collection process for identifying outages that don't yet have a network model ticket. The language also aims to clarify definitions of monitored priorities.
- *Revisions* to Manual 3 seek to add detail around the documentation of stability limits and would add references to generation interconnection agreements when discussing interconnection service agreements.
- The periodic review of Manual 10 led to recommended *revisions* clarifying that, when reporting outages in eDART, non-capacity resources should report their full nameplate capability unless physically derated.
- PJM proposed *revisions* to Manual 14D requiring that all generation resources prepare for cold weather operations and expanded the guidance it provides for its cold weather checklist. The recommendations for combustion turbine operators encourage proactive action to avoid unexpected icing that could occur due to proximity to sources of warm, moist air such as rivers or cooling tower plumes. The proposal also includes recommendations for ensuring de-icing capabilities are prepared for wind turbines, liquid-cooled inverters have anti-freezing capabilities and designating a "freeze protection operator" to plan preventative measures for critical equipment. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Stakeholders Endorse Reserve Requirement Study Values

VALLEY FORGE, Pa. — The Planning Committee endorsed the installed reserve margin (IRM) and forecast pool requirement (FPR) values PJM *recommended* in the 2023 Reserve Requirement *Study* (RRS), which calls for an increase in procured capacity for the 2027/28 delivery year (DY). (See "First Read of 2023 Reserve Requirement Study," *PJM PC/TEAC Briefs: Sept. 5, 2023.*)

The IRM, which sets the targeted capacity level above expected loads, would rise from 14.7% for the 2026/27 DY in the 2022 study to 17.6% for the 2027/28 DY. The FPR, which includes forced outage rates, also would increase from 9.18% to 11.65% for the corresponding DYs. The figures are slated to be considered by the Markets and Reliability Committee (MRC) and Members Committee (MC) next month, followed by the Board of Managers in December.

2023 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2023	2024 / 2025	17.7%	5.10%	1.1170
2023	2025 / 2026	17.7%	5.09%	1.1171
2023	2026 / 2027	17.7%	5.08%	1.1172
2023	2027 / 2028	17.6%	5.06%	1.1165

2022 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2022	2023 / 2024	14.9%	4.87%	1.0930
2022	2024 / 2025	14.8%	4.83%	1.0926
2022	2025 / 2026	14.7%	4.81%	1.0918
2022	2026 / 2027	14.7%	4.81%	1.0918

The recommended values for the installed reserve margin and forecast pool requirement under PJM's Reserve Requirement Study would increase the amount of reserves the RTO aims to procure. | *PJM*

This year's RRS included a few differences from past analyses, including a second methodology for setting the IRM and FPR using the hourly loss-of-load modeling developed for effective load-carrying capability (ELCC) studies. PJM also included data from the 2014 polar vortex and the December 2022 winter storm, reversing a historical practice to not include the polar vortex data in the study's modeling based on the impact of Winter Storm Elliott.

PJM's Patricio Rocha Garrido said the main drivers for the recommended reserve margin increase are higher uncertainty in peak load forecasts and the higher forced outage rates in the winter owing to extreme weather. Shifting to hourly modeling of peak loads, separate from the ELCC analysis, also contributed to the higher margins.

Minimal coincidence between the PJM peak load period and the "world" peak — which is defined as *MISO*, *NYISO*, TVA and VACAR — more than doubled the capacity benefit of ties (CBOT) value to 2.2% from 1% in the 2022 study. To reduce volatility, PJM elected to average the CBOT values from 2017-22 and use that figure, which landed at 1.5%, instead.

The load model, which included data from 2013-19, contributed to a 2.1 percentage point increase in the IRM, while the winter peak week caused a 1.1 percentage point increase. The values were slightly lower for the FPR drivers. The 1.5% CBOT contributed to a 0.5 percentage point decline in the IRM value and 0.58 percentage point decrease in the FPR.

The hourly approach resulted in higher recommended values — an IRM of 18.3% for the 2027/28 DY and a 12.31% FPR — with much of the difference from the PRISM values arising from the load model. PJM ran both models for this year's RRS analysis, but it plans to shift to only using the hourly approach in the long term.

During an August Resource Adequacy Analysis Subcommittee meeting, James Wilson, a consultant to state consumer advocates, calculated that the recommended values would constitute an approximate 3,700-MW increase in the summer reserve margin.

More Extensive Guidelines for Load Forecast Adjustment Endorsed

Stakeholders endorsed a PJM quick fix proposal to increase the granularity of the data included in load forecasting requests, as well as how far out it should seek to adjust future load estimates. The quick fix pathway allows a problem statement and issue charge to be brought concurrent with a proposed solution. (See "PJM Presents Quick Fix on Load Forecast Guidelines," *PJM PC/TEAC Briefs: Sept. 5, 2023.*)

Under the proposal, load forecast adjustments would need to include a 15-year forecast and the granularity of the load history electric distribution companies (EDCs) and load serving entities (LSEs) are asked to provide would be increased to hourly. If no load history exists, the adjustment request should include the "expected hourly behavior of load."

Requests would be required to come with a public document detailing how the forecast adjustment was calculated. Also, the process of assessing adjustments would begin earlier, with the Load Analysis Subcommittee (LAS) initiating its work in September and October under the proposal.

PJM's Molly Mooney said the proposal is focused on data center loads, which are difficult to capture in the RTO's existing processes, which rely on federal labor data that doesn't match up well with the electrically intensive data industry. Data center developments also tend to have a short period between their initial requests to interconnect and their in-service date, making advanced forecasting more critical.

Wilson said the proposed language doesn't make it clear that PJM is only seeking to add the amount of the forecast above the embedded amount and not double count loads already captured in the existing analysis. He encouraged PJM to hire a consultant with the expertise to do a 15-year forecast of data center loads, rather than leaving it up to EDCs and LSEs to report their own expectations and data.

PJM has made some modifications to the proposed Manual 19 revisions since the proposal's first read in September, specifying that when the RTO conducts annual information requests about significant shifts in load from electric distribution companies (EDCs), it is seeking information about changes within their service areas. The new language also states that any documentation of EDCs' or LSEs' internal financial or planning forecasts supplied to PJM will be confidential.

First Read of Periodic Review of Manuals 19 and 14B

PJM presented a first read of several revisions to Manuals 19 and 14B resulting from the documents' periodic review.

Revisions to Manual 19 added information reflecting the change to hourly peak load modeling in the load forecast and sought to clarify the procedure when forecasting price-responsive demand.

The *changes* to Manual 14B are intended to clarify that the 300 MW load loss criteria — which is meant to address load loss impacting a large number of customers — would be expanded to specify that it covers numerous customers, rather than single large-load customers such as data centers. PJM would also be granted the ability to review instances of the rule case by case. The criteria is a consideration when modeling outages in the Regional Transmission Expansion Plan (RTEP).

Both sets of manual changes are set to be considered for endorsement by the PC at its Oct. 31 meeting.

Transmission Expansion Advisory Committee

AEP Proposes $216 Million in Transmission to Support New Steel Mill

American Electric Power (AEP) *proposed* a $215.8 million project to construct several 345-kV lines and a new substation to serve a new industrial customer with an estimated 450 MW load near Apple Grove, W.Va.

In the first phase of the project, two new 345-kV lines would be cut into the Sporn–Tri-State line to run to a new Mercers Bottom 345-kV substation. The customer would be served by two single-circuit 345-kV feeds around 0.75 miles from Mercers Bottom, as well as a 138-kV line that would be cut into the Apple Grove–South Point line. The total phase one cost is estimated at $70.8 million with an estimated in-service date of Dec. 15, 2025, to meet the customer's request to interconnect by the end of 2025.

Phase two would focus on meeting the customer's short circuit strength needs under N-1 contingencies and would involve constructing an additional 26-mile 345-kV line from Sporn to Mercers Bottom, accompanied by an additional circuit breaker at Sporn. The projected in-service date for phase two is Dec. 15, 2029.

AEP said the industrial customer is a steel mill planned in the region, but it could not provide further detail at this time. Nucor is planning to construct a $3.1 billion electric arc furnace steel mill in Apple Grove with power supplied by a new Appalachian Power substation, according to an announcement from Sen. Joe Manchin (D).

Other Supplemental Projects:

- Commonwealth Edison (ComEd) *proposed* a $149 million rebuild of its 26.4-mile Kincaid–Pana (Ameren) line, saying 56-year-old wood poles and components are at their end of life and have sustained woodpecker damage. The line also suffered outages when crossarms broke under clear weather conditions. The project, still in the conceptual phase, has an estimated in-service date of Dec. 31, 2026.
- ComEd also proposed a $264 million project to replace a 345-kV straight bus with a gas insulated substation with 34 circuit breakers in a breaker and half configuration. The utility stated that 14 breakers are deteriorating and a failure of one could cause an outage on seven 345-kV lines and two autotransformers. The project is in the conceptual phase with an estimated in-service date of Dec. 31, 2028.
- Dominion *submitted* needs for two new 230-kV substations, World Gate and Mercator, in Fairfax County, Va., to serve data centers with loads exceeding 100 MW. The needs have a targeted in-service date of June 1, 2027. ■

— Devin Leith-Yessian

Company Briefs

GM Agrees to Place EV Battery Manufacturing Under UAW Agreement

General Motors has agreed to place battery manufacturing for EVs under its main agreement with the United Auto Workers (UAW) union, UAW President Shawn Fain announced last week.

Fain said the union won't expand its strike against the automakers following the last-minute development in negotiations.

Autoworkers had expressed concerns about the shift toward EVs given that most are made with non-union labor and outside of the U.S.

More: *The Hill*

Hyundai, Kia EVs to use Tesla's Charging Ports Starting Next Year

Hyundai and Kia last week said they will adopt North American Charging Standard ports for their EVs in the U.S. and Canada, which will give the vehicles access to Tesla Superchargers.

Hyundai Motor North America said that new EVs in the U.S. and Canada will come with the NACS port starting in 2024 and 2025, respectively. Kia plans to build the port into new EVs sold in the U.S., Canada and Mexico in the fourth quarter of next year.

More: *The Associated Press*

Reid Retiring as Dominion Energy Services President

Carter Reid, the executive vice president, chief of staff and corporate secretary of Dominion Energy, as well as president of Dominion Energy Services, will retire on Jan. 1, 2024.

Carlos Brown, the company's senior vice president, chief legal officer and general counsel, will be promoted to president of Dominion Energy Services and Dominion Energy executive vice president, chief legal officer and corporate secretary.

Reid joined Dominion in 1996 as its assistant general counsel and held roles in its law department and at Dominion Energy Services before being promoted to her current role in 2019.

More: *Virginia Business*

Federal Briefs

NRC Rejects Request to Shut Down Diablo Unit

The Nuclear Regulatory Commission last week took no action following a request from environmental groups Friends of the Earth and Mothers for Peace to immediately shut down one of two reactors at the Diablo Canyon Nuclear Power Plant.

The group said in a petition filed last month with the NRC that long-postponed tests needed to be conducted on critical machinery at the plant, and argued the equipment could fail and cause a catastrophe.

The NRC instead asked agency staff to review the petition.

More: *The Associated Press*

EPA Sets New Rules to Tackle HFCs

EPA last week announced two new measures aimed at reducing hydrofluorocarbons (HFCs) that can help the U.S. meet its goals to halve its greenhouse gas emissions this decade.

The agency issued a final rule that restricts the use of HFCs used in 40 types of imported or domestically-manufactured foams and aerosol products, as well as refrigeration, air conditioning and heat pump equipment, setting compliance dates from 2025 to 2028.

EPA also issued a proposal that aims to improve how HFCs are managed and reused, setting requirements for repairing leaky equipment, rules for using reclaimed HFCs and leak detection rules for large refrigeration equipment.

More: *Reuters*

PNM, EEOC Settle Discrimination Lawsuit

The Public Service Co. of New Mexico and PNMR Services reached a settlement with the U.S. Equal Employment Opportunity Commission and will pay $750,000 to settle an employment discrimination lawsuit.

The lawsuit alleged the company fired or retaliated against employees who were disabled, including from injuries that happened on the job.

The agreement set terms for a two-year consent decree. The terms include paying 10 people $750,000 in back pay and compensatory damages. The agreement also requires PNM not to engage in disability discrimination and retaliation.

More: *Albuquerque Journal*

State Briefs

ARKANSAS

Natural Gas Pipeline Erupts Near Jessieville

Residents in the Jessieville area were evacuated early Oct. 4 after a natural gas pipeline ruptured, sending a plume of flame 200 to 300 feet in the air.

According to the National Pipeline Mapping System, Enable Gas Transmission LLC operates the line.

Garland County Department of Emergency Management Director Bo Robertson said no injuries had been reported at press time. Robertson said the evacuation area extends up to 1 mile from the site.

More: *Arkansas Democrat Gazette*

CALIFORNIA

Orange County Sues T-Mobile, SoCal Edison for Recent Wildfires

Orange County last week filed a pair of lawsuits against Southern California Edison in which it alleges the company's equipment played a role in wildfires in 2020 and 2022.

The county said in the lawsuit that it believes that the Coastal Fire (May 2022) was caused by a failure on a utility pole that supported a distribution line. The county alleged the incident occurred because SCE failed to maintain its facilities in a safe manner in an area of significant wildfire risk. In a separate lawsuit, the county said the Silverado Fire (October 2020) may have been sparked when a telecommunications wire contacted an electric conductor. The county also named T-Mobile in the suit, which prompted the evacuation of tens of thousands of people and caused school closures.

More: *CBS Los Angeles*

San Jose Votes to Create City-owned Utility

The San Jose City Council last week unanimously approved the creation of a city-run utility called San Jose Power.

The council said the creation of San Jose Power is in an exploratory phase, and will still need years of research to determine if a publicly owned and operated utility is worth the investment. The city's initial study estimates a 15% to 25% savings on electricity.

According to the city, the council will not make its first major financial decision on San Jose Power until 2025.

More: *San Jose Spotlight*

ILLINOIS

AG Sues Alternative Electric Supplier for 'Deceptive' Tactics

Attorney General **Kwame Raoul**'s (D) office last week announced it is suing alternative electric supplier Residents Energy, accusing the company of "deceptive and unfair tactics" that made some residents liable for "millions" more in energy costs.

The lawsuit accuses the company of promising "historically low" first-month rates without disclosing they were temporary deals. From 2018 to 2020, Residents Energy customers paid 55% ($15 million) more than they would have with ComEd, the complaint says.

A hearing date is set for Jan. 30, 2024.

More: *Chicago Sun-Times*

IOWA

Utilities Board Lets Navigator Pause Build of Carbon Pipeline

The Utilities Board last week agreed to let Navigator CO2 Ventures pause its plan to build a carbon capture pipeline across Iowa while the company awaits regulatory action on a crucial section of the pipeline in Illinois.

Navigator told the board last week it wanted to pause its request while it awaited a decision from the Illinois Commerce Commission. The company had withdrawn its Illinois application in January, then refiled after adding a section of pipeline to reach more sequestration locations. Navigator also said it's reassessing its Iowa route in "light of decisions from regulatory authorities in neighboring states and individual landowner requests."

More: *Des Moines Register*

MISSOURI

PSC OKs Evergy Changing Default Time-of-use Pricing Plan

The Public Service Commission last week approved Evergy's request to change the default selection for customers who fail to select one of the company's four time-of-use pricing plans.

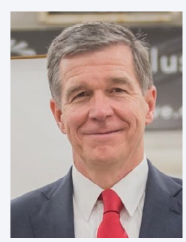
The PSC ordered Evergy to implement time-of-use pricing, which places a premium on electricity used during periods of high demand. Initially, Evergy would have enrolled customers in the Standard Peak Saver if they didn't pick another plan. Under that plan, electricity on summer afternoons will be four times the price that it is the rest of the day. But now, the default plan will be closer to traditional pricing with smaller differences between its highest and lowest rates.

Evergy last month requested that the pricing program be optional. However, following criticism from the Office of the Public Counsel, the utility withdrew the request last week.

More: *Missouri Independent*

NORTH CAROLINA

Cooper Vetoes Bills That Would Hurt Climate Efforts



Gov. **Roy Cooper** (D) last week vetoed two bills that he said would undermine his administration's efforts on the environment and climate change.

Cooper vetoed House Bill 600, this year's regulatory reform bill, as well as Senate Bill 678, which redefines clean energy to promote Duke Energy's plans to build new nuclear plants. Among other things, provisions in the regulatory reform bill would have sped up permitting for a proposed extension of the Mountain Valley Pipeline.

More: *WFAE*

Robeson County Approves $125M Solar Farm

The Robeson County Board of Commissioners last week unanimously approved a special use permit for a $125 million solar farm.

The 80-MW farm, which would be constructed by Robeson Solar and parent Applied Energy Services Clean Energy, would be constructed on a combined 1,307-acre tract of land.

The farm is expected to be operational by 2027.

More: *The Robesonian*

TENNESSEE

MLGW Proposing Rate Increases Over Next 3 Years

Memphis Light, Gas & Water leadership is proposing rates increase that would total 12% over the next three years.

It is one year earlier and 1.5% higher than previously planned, but CEO Doug McGowen said customers cannot wait for needed improvements and the rate increase will allow MLGW to take steps to solve electrical interruptions. The total increase of 12% over the next three years (4% each year) will go toward $1.2 billion in improvements to electrical distribution over five years.

McGowen said the budget will need to be approved by the MLGW board and the Memphis City Council before the next fiscal year starts on Jan. 1.

More: *Memphis Commercial Appeal*

VIRGINIA

Dominion Energy Proposes New Solar Projects

In its fourth annual clean energy filing with the State Corporation Commission, Dominion Energy last week proposed a slew of new projects.

The proposal, if approved, will help the company add six solar projects and include 13 power purchase agreements with the combined capacity of 772 MW.

The cost of the projects is estimated to add about $1.54 to the average monthly bill. Construction is expected to be completed between 2024 and 2026.

More: *Reuters*

WYOMING

BLM's 'Conservation' Proposal Could Limit Large Energy Projects

Undeveloped areas of the state will be largely off-limits to industrial-scale energy projects under the Bureau of Land Management's preferred "conservation" scenario for managing 3.5 million acres of federal land in southwest Wyoming.

Nearly 2.5 million acres would be excluded from consideration for new rights-of-way. That is a 481% increase in acreage off-limits to things like maintained roads, power lines and pipelines. BLM officials say it is also a means to inhibit permanent industrial facilities in other areas because they typically require infrastructure like power lines and pipelines.

However, an examination of the exclusion areas suggests a recognition of marginal development opportunities, particularly for wind, solar and geothermal energy, according to Outdoor Council Energy and Climate Policy Director John Burrows.

More: *WyoFile*