ISSN 2377-8016 : Volume 2022/Issue 34 ▪ August 23, 2022

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

COVER: Calpine Hay Road Energy Center, Wilmington, Del. |

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 658-6885

2022 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,620
Newsletter PDF Plus Web	$2,100

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal News

Battle Lines Drawn on FERC Tx Planning NOPR

Commenters Disagree over ROFR, GETs, 20-Year Timeline

By Rich Heidorn Jr. and Sam Mintz

Transmission lines in Wilmington, Del. | *© RTO Insider LLC*

FERC's proposed overhaul of its transmission planning and cost allocation rules received mostly supportive comments from industry stakeholders, but some criticized its requirements as overly prescriptive and said 20-year planning horizons could lead to speculative and unnecessary projects.

Stakeholders also disagreed sharply over whether the commission should reinstitute a federal right of first refusal (ROFR) for incumbent transmission owners.

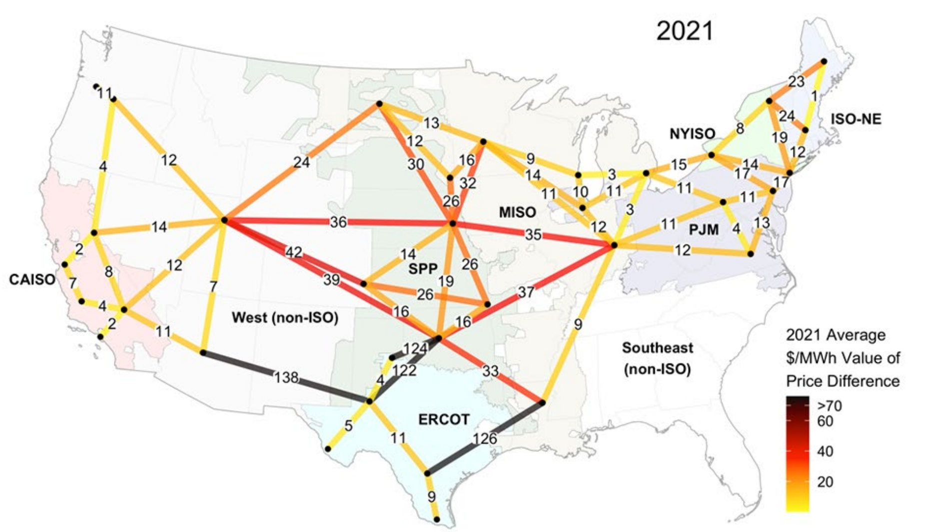
More than 180 comments had been filed by utilities, public interest groups, industrial consumers, RTOs and ISOs and state officials by Wednesday's 5 p.m. ET deadline (RM21-17). Reply comments are due Sept. 19.

The Notice of Proposed Rulemaking, approved by the commission April 21 on a 4-1 vote, would direct transmission providers to identify infrastructure needs on a long-term, forward-looking basis and propose a list of benefits on which they would base their selections of proposed projects.

The NOPR said the new rules would help planning entities prepare for the growth of renewables, new sources of demand such as electric vehicles and extreme weather events, expected to increase as climate change worsens. (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

As always, numerous commenters urged the commission to allow regional flexibility and not to impede innovations already being pursued.

The ISO/RTO Council (IRC), representing the six FERC-regulated grid operators, said "many" of its members already engage in "long-term planning ... or have ongoing initiatives" to develop such procedures. MISO, CAISO, NYISO and SPP employ a 20-year horizon in at least some of their planning processes, while PJM uses 15 years and ISO-NE uses 10 years, the IRC said.



Congestion across regions is often higher than congestion within regions, suggesting interregional transmission could produce economic gains, Lawrence Berkeley National Laboratory found. | *Lawrence Berkeley National laboratory*

The IRC said the commission was "overly prescriptive" on some issues.

"The proposed rule is very focused on process but needs to provide more clarity on how these processes produce actionable results," the IRC said. "Without discretion to adapt the scenarios, factors and benefits to regional circumstances, the final rule could end up leading to *more* conflict, rather than useful transmission planning for needed infrastructure. Instead of prescribing detailed procedures, the IRC believes that the final rule should state high-level, long-term planning principles that transmission planners must consider, and then authorize them to craft their own processes that are tailored to their regional needs."

ISO-NE *cautioned* the commission against setting uniform implementation requirements for long-term scenario analyses or "hardwiring these details into the region's tariff."

"In ISO's experience with transmission planning based on scenario analysis, these actions will limit the efficacy of the studies," it said.

FERC/Federal News

SPP added: "If the commission specifies requirements that are expansive in scope and prescriptive in detail, this could become duplicative with SPP's current processes and initiatives and place unnecessary burden on the future state of SPP planning."

20-Year Planning Horizon

Commenters — including Minnesota's Public Utilities Commission and Department of Commerce, the SPP Market Monitoring Unit and the U.S. Department of Energy — endorsed FERC's call for a minimum 20-year time horizon for transmission planning, with reassessments and revisions to the scenarios at least every three years.

"Traditional transmission solutions that benefit an entire region can take more than a decade to site, permit, and construct and require planning that is more than a decade into the future. Creating long-term scenarios that are at least 20 years into the future will capture power sector changes that occur during transmission development," DOE said. "However, for the evaluation period, the department encourages the commission to consider requiring an evaluation of transmission costs and benefits over a minimum of 30 years after in-service dates rather than the 20 years proposed in the NOPR."

But others, including the Nebraska Power Review Board, said any 20-year horizon should be used only for guidance and not to identify transmission upgrades.

"While there is no crystal ball when it comes to transmission planning for the future, PJM continues to believe a 15-year planning horizon allows for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities while reducing input assumption risks associated with a 20-year horizon," the RTO said.

Industrial Energy Consumers of America, the American Forest & Paper Association, the PJM Industrial Customer Coalition and the Coalition of MISO Transmission Customers said "a 20-year planning horizon for new transmission has not been shown to be just and reasonable."

NRG Energy said a 20-year planning horizon should be "only for purely informational purposes and not as a basis to mandatorily allocate investment costs." It said a 10-year maximum planning horizon was more appropriate when applying involuntary cost allocation.

"While it is true that transmission development takes time and thus can be served by a longer view forward, it is also true that identifying a transmission project solution up to 20 years in the future could prove to be problematically speculative," said the Electric Power Supply Association (EPSA). "A longer view could also lock in a specific approach to the detriment of any other solution that could be developed on a more timely basis or close the door to options for a transmission project that does not reach the final phase of development, which is all the more likely decades out. This could also prove to be short-sighted based on the pace of technological change."

Calpine Hay Road Energy Center, Wilmington, Del. | *© RTO Insider LLC*

WIRES, which represents transmission providers and developers, said FERC should allow variances from the 20-year requirement "in order to account for regional differences or circumstances that would render such a timeline inappropriate."

Non-profit GridLab said the NOPR "conflates the planning horizon with the time horizon over which benefits and costs are calculated in benefit-cost analysis (BCA)."

"FERC should clarify the distinction between the two … while maintaining requirements for a 20-year planning horizon and a 20-year period for BCA. The main benefit of a longer planning horizon will likely be capturing changes in transmission value (benefits) over a longer time horizon, which assumes that the value of regional transmission will look very different in the 2030s than it does today. There is indeed evidence that this will be the case, though some of the forces driving change in regional transmission value will increase value (e.g., growth in wind and solar generation, increased risk of extreme events), while others will decrease it (lower cost energy storage, growth in distributed energy resources). The balance can only be determined through rigorous planning and risk assessment."

Grid-enhancing Technologies

FERC's support for grid-enhancing technologies received wide support, but the Los Angeles Department of Water and Power (LADWP) said the commission's singling out of technologies such as dynamic line ratings (DLRs) and advanced power flow control devices (APFC) "seems inappropriate."

"Transmission providers should have the range of available technologies for evaluation of solutions to meet economic, reliability and security needs in their respective regions," LADWP said. "A rule that specifically calls out certain technologies as solutions is in danger of being biased, prescriptive and incomplete."

ISO-NE said FERC should not mandate use of DLRs in lieu of transmission. "This technology cannot substitute for transmission facilities needed to solve system needs," it said.

Potomac Economics, which performs market monitoring for MISO, NYISO, ISO-NE and ERCOT, said the commission should also require transmission providers to consider transmission switching and network optimization in addition to DLR and APFC. "Like GETs, network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion. In this case, investing millions in upgrading such a facility could prove wasteful and inefficient," it said.

The Working for Advanced Transmission Technologies (WATT) Coalition, a trade group supporting GETs deployment, asked the commission to be more prescriptive, saying it should "specifically require evaluation of APFC for thermal overloads that fall within 50% of the line rating" and for network upgrades for new loads.

Right of First Refusal

There was also no consensus on the commission's proposal to allow incumbent transmission owners a federal ROFR on regional projects on the condition that they partner with an unaffiliated company with a "meaningful level of participation and investment" in the project. (See *ANALYSIS: FERC Giving up on Transmission Competition?*)

Among those opposing the proposal were Electricity Consumers Resource Council, which represents large industrial consumers, and EPSA.

"Rather than less independence and accountability, there must be more independence and accountability in regional transmission planning processes to ensure that all options are offered and assessed to meet expected cost and time parameters pursuant to the planning process," EPSA said.

"Because competition serves to discipline costs, allowing the incumbent transmission utility to exercise a ROFR, even if done in partnership with another entity, could expose load to higher costs," said the Pennsylvania Public Utility Commission. "To the extent that FERC determines that the elimination of the ROFR by Order No. 1000 resulted in transmission providers focusing on local projects rather than regional projects, the solution is not to appease incumbent transmission owners' reluctance to engage in competition from nonincumbent transmission developers, by restoring the ROFR. … Such a mechanism clearly grants preferential treatment to the incumbent transmission providers and discriminates against competitive transmission developers, in violation of the principle of an 'open' transmission planning process, as articulated in Order No. 890."

NRG said FERC should withdraw the proposal "and instead eliminate formula ratemaking and other aspects to its regulatory scheme that have caused transmission developers to avoid regional projects."

FERC approved the transmission planning NOPR in April. | © *RTO Insider LLC*

Transmission owners and the Edison Electric Institute expressed support for a renewed ROFR.

"Although in some instances, the lack of a ROFR may have arguably increased the number of innovative and/or cost-effective transmission options for consideration, it has also caused delays and limited opportunities for dialogue between transmission developers, market participants and RTOs/ISOs, in addition to not delivering regional transmission projects under the time frames necessary to meet increasingly aggressive climate targets," WIRES said.

NEPOOL said it does not have a formal position on the conditional ROFR but noted it has previously advocated for competitive processes for transmission development. "To the extent the final rule provides for a conditional ROFR, the commission should maximize the opportunities and requirements for competitive processes to be used within that construct," NEPOOL said. "This objective could be achieved potentially through guidelines for the criteria to be used in establishing joint ownership and development of regional transmission facilities."

The Minnesota agencies noted that the state's legislature has backed a state ROFR and said FERC's joint ownership model "would create additional complexity but is not likely to provide the anticipated innovation and cost-control benefits." (See *Courts Uphold Minn. ROFR, MISO Cost Allocation*.)

"Continuing to clearly align the responsibility to construct, own and maintain the high-voltage transmission system in our state with the related decision-making authority that has been given to the responsible utilities remains the best ownership model, at least for now," they said.

States' Roles

State regulators and others urged FERC to let states take a central role in planning.

ISO-NE noted that the New England States Committee on Electricity's role in determining the range of scenarios to be plugged into the grid operators' studies. Therefore, ISO-NE said, "the states should be responsible for determining whether to move forward with transmission and the associated cost allocation method, with the ISO playing a supporting, technical role."

FERC should "explicitly authorize or allow for … greater state involvement in all aspects of policy-based transmission planning — not just the criteria for selecting and methodology for allocating costs of long-term transmission facilities," ISO-NE said.

"FERC should reframe long-term regional transmission planning as an informational process with no attendant project selection or construction obligations unless the affected state regulators first support such actions consistent with their regulation of the public utilities subject to their respective jurisdictions," said the Alabama Public Service Commission.

The National Association of State Energy Officials praised FERC's creation of the Joint Federal-State Task Force on Electric Transmission as a "welcome advancement of federal-state coordination."

But it said "FERC's engagement on these issues needs to include additional state agencies, such as state energy offices." ■

FERC/Federal News

Biden Signs Inflation Reduction Act

New Law Will be Centerpiece of Admin's 'Building a Better America' Campaign

By K Kaufmann

At the White House, (from left) Sen. Joe Manchin, Senate Majority Leader Chuck Schumer, Rep. Jim Clyburn, Rep. Frank Pallone and Rep. Kathy Castor look on as President Joe Biden signs the Inflation Reduction Act on Aug 16. | *The White House*

President Biden signed the $740 billion Inflation Reduction Act (*H.R. 5376*) into law Aug. 16, kicking off an aggressive pre-midterm election campaign that, an *executive memo* said, "will use all the tools of the White House" to promote the law and its benefits to voters across the country.

Returning early from a family vacation in South Carolina, Biden put his signature to the new law surrounded by some of the key lawmakers who helped push it to passage, including Sen. Joe Manchin (D-W.Va.) Senate Majority Leader Chuck Schumer (D-N.Y.), and Reps. Jim Clyburn (D-S.C.), Frank Pallone (D-N.J.) and Kathy Castor (D-Fla.).

And he made immediate use of the White House bully pulpit with a passionate speech about the IRA and what it represents for the country, laying out the Democratic talking points for the November midterms.

Pointing to other recently passed legislation such as the Infrastructure Investment and Jobs Act and the CHIPS and Science Act — which aims to boost semiconductor manufacturing in the United States — Biden said, "We are in a season of substance. … We're delivering results for the American people. We didn't tear down; we build up. We didn't look back; we look forward; and today offers further proof that the soul of America is vibrant; the future of America is bright; and the promise of America is real and just beginning."

The IRA's $369.75 billion in energy funding will, Biden said, "allow us to boldly take additional steps toward meeting all my climate goals," which include decarbonizing the U.S. electric grid by 2035 and creating a net-zero economy by 2050. "It's going to offer working families thousands of dollars in savings by providing them rebates to buy new and efficient appliances, weatherize their homes, [and] get tax credits for purchasing heat pumps and rooftop solar, electric stoves, ovens [and] dryers." (See *What's in the Inflation Reduction Act, Part 1*.)

A White House *fact sheet* released Aug. 15 parsed out the savings, including $1,000/year from clean energy and electric vehicle tax credits and $350/year from rebates on heat pumps and other energy-efficient appliances.

Biden also stressed the new law's potential for creating "clean energy opportunities in frontline and fenceline communities that have been smothered by the legacy of pollution and [fighting] environmental injustice."

The bill signing ends a three-week marathon by congressional Democrats to get the slimmed-down budget reconciliation package — originally the $2.2 trillion Build Back Better Act — to Biden before beginning their August recess and midterm campaigns. After behind-closed-doors negotiations, Schumer and Manchin unveiled the draft of the bill on July 27. The Senate passed it on a straight party-line vote on Aug. 7, followed by a similar vote in the House of Representatives on Aug. 12.

On Aug. 16, Biden handed the pen he used to sign the bill to Manchin, signaling his thanks for the West Virginian's role in drafting and passing the IRA.

"This important legislation will give energy companies the certainty they need to increase domestic energy production while also lowering energy and health care costs and pay down our national debt without raising costs for working Americans," Manchin said in a *statement*. "I look forward to following this momentum by passing comprehensive permitting reform next month to ensure these investments become the energy projects we need to decarbonize and boost energy security."

Reaction

Clean energy organizations quickly offered statements of thanks and praise but, like Manchin, also called for further action.

The IRA's clean energy funding "is not a cure-all but rather an overdue federal component to combat the climate crisis," said Stephen Smith, executive director of the Southern Alliance for Clean Energy. "This federal investment is a necessary cornerstone for climate action and clean energy commitments that must accelerate in all sectors of the economy on all levels — including state and local governments, the utilities that generate and deliver our electricity, corporations, and the collective actions of citizens."

"Small businesses across the nation stand ready to deliver on the promise of this historic clean energy and climate legislation," said Lynn Abramson, president of the Clean Energy Business Network. "The Inflation Reduction Act marks the start of a new era for deploying cleantech at unprecedented scale to drive down energy costs, cut emissions and boost our energy security."

Abigail Ross Hopper, president and CEO of the Solar Energy Industries Association, said the new law provides "a long-term framework … for the solar and storage industry to drive

FERC/Federal News

economic growth in every zip code across the country."

"It features long-term investments in clean energy and new incentives for energy storage, which give solar and storage businesses a stable policy environment and the certainty they need to deploy clean energy," Hopper said.

Daniel Bresette, executive director of the Environmental and Energy Study Institute, said the new law will also send a message to other countries that the U.S. is serious about cutting its carbon emissions as they prepare for the next U.N. Climate Conference of the Parties in Egypt in November. "I hope this law will encourage world leaders to make more ambitious climate commitments, followed by their own transformative investments, and provide adequate support for decarbonization and climate adaptation efforts by developing countries."

Judi Greenwald, executive director of the Nuclear Innovation Alliance, welcomed the law's funding for advanced nuclear development, in particular its $700 million "to help make high-assay low-enriched uranium available for advanced reactor demonstration and commercialization through public and private partnerships and actions."

But, echoing others, Greenwald said, "enactment of the IRA is just the beginning: Swift and effective implementation of this law will be crucial to ensuring it meets the goals intended by Congress and supported by the president with his signature today."

'Biden Backlash'?

Biden's speech at the signing provided a preview of the Biden administration's talking points for its "Building a Better America" campaign, in which "cabinet members will travel to 23 states on over 35 trips touting the Inflation Reduction Act and the administration's accomplishments," according to the White House memo first published by POLITICO.

For example, on Wednesday, Agriculture Secretary Tom Vilsack will be in Colorado for a roundtable discussion on the law's benefits for agricultural stakeholders, while Interior Secretary Deb Haaland will be in California to talk about funding to tackle drought resilience. Digital strategy will include a "new, interactive website on climate incentives, including information for families, homeowners, small businesses and more on access to tax credits."

The campaign will also develop "essential collateral": talking points, graphics and state-by-state fact sheets to be distributed to state, local, tribal and territorial leaders.

Written by White House Deputy Chief of Staff Jen O'Malley Dillon and Senior Adviser Anita Dunn, the memo notes that "our internal polling shows that messages touting the cost-lowering features of the Inflation Reduction Act — lowering health costs, prescription drug costs and utility bills — are among the highest testing messages ever."

Another core message of the campaign will emphasize how "the president and congressional Democrats defeated special interests," while Republicans sided with special interests.

But industry analysts ClearView Partners argue that the new law could trigger "a new wave of 'Biden backlash' — a GOP-led defense of legacy economic franchises against energy transition technologies and environmental, social and governance (ESG) standards."

With Democrats seen as the party of green energy and Republicans the party of fossil fuels, ClearView predicts a 2023 Biden backlash in state legislatures, focused on four types of energy initiatives:

- restrictions on the closure of existing gas- or coal-fired plants;
- imposition of production taxes — as opposed to production tax credits — on renewable energy generation;
- siting restrictions on new solar and wind; and
- bans on local restrictions or prohibitions on natural gas hook-ups.

Republican leaders last week similarly provided a preview of the party's messaging ahead of the midterms.

"Democrats robbed Americans last year by spending our economy into record inflation," Senate Minority Leader Mitch McConnell (R-Ky.) *tweeted*. "This year, their solution is to do it a second time. The partisan bill President Biden signed into law today means higher taxes, higher energy bills and aggressive IRS audits."

"Biden just signed a bill to raise taxes during a recession, send the IRS after the middle class and give rich liberals tax credits to buy luxury electric vehicles," *tweeted* Ronna McDaniel, chair of the Republican National Committee.

But ClearView also sees a longer-term shift in which "party-line energy policy cleavages could fade due to fundamentals. Green power (wind energy especially) already contributes significantly to red-state generation mixes. As renewables proliferate on GOP-represented grids, their economic and political relevance to state (and federal) government officials seems likely to increase too." ■

CAISO/West News

California Legislature Asks CAISO to Report on Regionalization

Shows Interest in an ISO-led Market that Respects Other States' Autonomy

By Hudson Sangre

A measure that asks CAISO to report to California lawmakers on Western regionalization efforts and the potential benefits of greater interstate collaboration cleared the State Legislature this month, with some saying it could renew discussions of an RTO developed by the ISO.

"There is considerable potential for additional benefits for California consumers through further regional collaboration," and the state should "collaborate, coordinate on policy, and share systems and resources with our neighboring Western states when opportunities for mutual benefit exist," Assembly Concurrent Resolution 188 *says*.

"The legislature should have current and comprehensive information on the impacts to California of expanding the existing independent system operator into a regional organization that manages wholesale electricity markets, transmission planning and other services across a broader Western region."

Introduced by Assemblymember Chris Holden and co-authored by 75 lawmakers, ACR 188 passed the Senate and Assembly without opposition on Aug. 8 and 11 respectively. It asks CAISO to produce a report by Feb. 28, that summarizes recent studies on the impacts of expanded regional cooperation and identifies features that could advance the state's energy and environmental goals while "reflect[ing] the impact of regionalization on transmission costs and reliability for California ratepayers."

Transmission and resources needed to fulfill the 100% clean energy goal of 2018's Senate Bill 100 should be covered, as should mandates by Colorado and Nevada requiring transmission owners to join an RTO by 2030, it said.

The California State Capitol in Sacramento | *Andre m, CC BY-SA 3.0, via Wikimedia*

CAISO said the request signaled a growing interest in regional efforts.

"We're encouraged that compiling the many existing studies on this, as well as highlighting the other market efforts in the West, will foster a better understanding of the issues and how we might move forward collaboratively," Stacey Crowley, CAISO's vice president of external affairs, said in a statement.

Potential Benefits

In the resolution, lawmakers cited a study published last year that found an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion in annual electricity costs by 2030 and cut carbon dioxide emissions by 191 million metric tons. A group of Western states led the study, financed by the U.S. Department of Energy.

A subsequent study released in July by Advanced Energy Economy (AEE) looked at regional economic effects. It concluded an 11-state Western RTO could generate roughly $19 billion to $79 billion in additional gross regional product by 2030 and could help create 159,000 to 657,000 permanent jobs at an average total compensation, including benefits, of $73,000 a year. (See *Study Tallies Economy-wide Benefits of Western RTO*.)

AEE said the resolution "kickstarts discussions about California's role in improving the Western power grid in collaboration with other states in the region."

"ACR 188 sets the stage for California to engage substantively with its neighbors, and it's great to see the legislature recognize the importance of regional collaboration when it comes to our energy grid and achieving state goals," AEE Managing Director Amisha Rai said in a news release.

Prior regionalization efforts involving CAISO fizzled in 2016, 2017 and 2018, as California lawmakers balked at making changes to the ISO's governance that could open its Board of Governors to out-of-state members. CAISO is a public benefit corporation created by the legislature and led by five gubernatorial appointees from California.

CAISO/West News

Even as California has been unwilling to share CAISO leadership, many parties in other Western states are unwilling to participate in a California-dominated RTO.

Acknowledging the standoff, the resolution said CAISO's report should examine "collaboration between states on energy policies to maximize consumer savings while respecting state policy autonomy."

Western Resource Advocates said the resolution "sends an important signal that regional electric grid collaboration should respect individual states' autonomy and include governance provisions that allow significant engagement by states across the West."

Speaking for CAISO, Crowley said, "Perhaps today there's more general understanding of how a regional market would benefit ratepayers and the overall reliability, while at the same time respecting the policies set by each state in the West."

Regional Cooperation Efforts

CAISO's multistate Western Energy Imbalance Market has shown the economic benefits of regional cooperation by securing more than $2 billion in benefits for its members since it began in 2014, the resolution notes. Members from California and other Western states make up WEIM's Governing Body.

The ISO is engaged in a stakeholder process to expand the real-time WEIM to a day-ahead market with the potential to increase resource exchanges across the West. On Aug. 16, it posted a revised straw proposal on the extended day-ahead market (EDAM) initiative and has scheduled stakeholder meetings for Aug. 28 and Sept. 7-8. (See *CAISO Issues EDAM Straw Proposal for the West*.)

"The extended day-ahead market is expected to achieve cost savings through a more efficient day-ahead commitment of generating units, including the displacement of resource commitments within one balancing authority area when more economic resources can be committed in other balancing authority areas instead," the resolution says.

CAISO is facing competition from other entities that are moving to increase regional planning or form a Western RTO.

SPP has been promoting its Markets+ offering in the Western Interconnection, attracting interest from utilities seeking a range of market services that stop short of a full RTO. (See related story, *BPA Commits to Funding Markets+ Development*.) It is planning to establish a Western version of its eastern RTO, called RTO West, with Markets+ participants as likely members.

Spanning much of the Western Interconnection, the Western Resource Adequacy Program (WRAP) promises to be another significant player in regionalization efforts. Started by the Northwest Power Pool — which recently changed its name to the Western Power Pool (WPP) to reflect its wider reach — the program is meant to address reliability concerns in the Western Interconnection. It has already attracted participants in an area spanning from British Columbia to Arizona and east to South Dakota.

WPP has not signaled intentions to expand the WRAP's offerings beyond resource adequacy, but it appears increasingly as a possible platform for incrementally developing a Western RTO that could compete with SPP and CAISO. ■

CAISO/West News

BPA Commits to Funding Markets+ Development

Federal Agency Continues to Evaluate SPP, CAISO Market Offerings

By Tom Kleckner

The Bonneville Power Administration has said it will become the first Western utility to formally commit to funding further development of SPP's Markets+ offering in the Western Interconnection.

In an Aug. 12 *letter* to the Public Power Council's (PPC) Executive Committee, BPA Administrator and CEO John Hairston said that while the agency has not made a decision to join Markets+ as a market participant, it expects to fund its share of the market's development phase in late 2022 and to participate in drafting a tariff and market protocols next year.

"By supporting and participating in SPP's process, Bonneville and our customers can help shape the market design in a way that ensures it could work with our statutory obligations and support Bonneville's customers' needs and interests," Hairston said.

He said BPA's goal is to ensure the utility has a fully developed option "that could work for Bonneville" and that can be evaluate alongside CAISO's Extended Day-Ahead Market (EDAM) proposal. The agency will continue to take part in the EDAM development process as well.

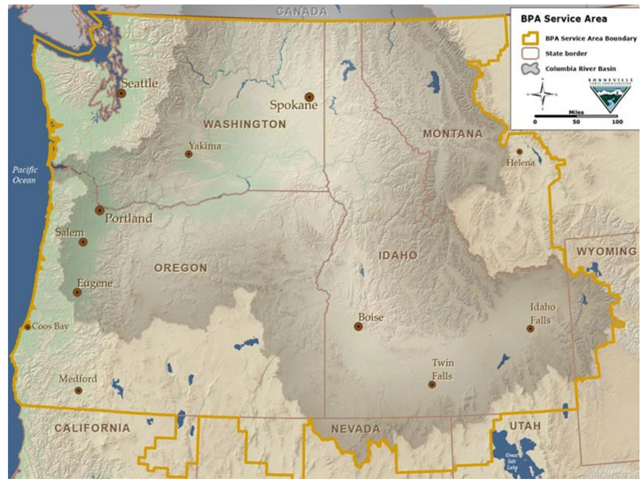
"Bonneville recognizes that independent governance is an essential aspect of any potential future market to ensure neutrality in market development, implementation and operation," Hairston wrote. "While some aspects of the Markets+ governance proposal can be improved upon, Bonneville is encouraged by the representative nature of SPP's existing governing structure and its participant-driven process."

He said BPA supports the Markets+ governance proposal that includes independent, West-wide participation.

"Bonneville is also encouraged by SPP's track record of accommodating the unique characteristics and statutory requirements of the Western Area Power Administration in its other markets and SPP's long history of working with public power in its Eastern region," Hairston said.

The letter was in response to an earlier *letter* from the PPC, which represents the Pacific Northwest's public utilities in the region and in D.C. The PPC encouraged BPA to commit to a "fully informed decision" on meeting customers' "evolving needs in the context of a rapidly changing Western electric grid."

"This was welcome news as we look to evaluate all options on the table," PPC Executive Director Scott Simms said in an email to *RTO Insider*. "Specifically, we in Northwest public power will continue to evaluate CAISO's EDAM approach along with SPP Markets+ approach, with an eye to the governance structure and overall market design path that can create the greatest value to BPA and its customers in the Pacific Northwest."



The Bonneville Power Administration's footprint in the Northwest | *BPA*

BPA's decision is significant, as it is the region's 800-pound gorilla with 15,000 circuit miles of transmission that serve the region. Its footprint's size has been compared to France, and it serves nearly 3 million people.

The PPC's members are among the largest purchaser of the utility's transmission products and services. It said it is closely watching BPA to determine whether it will continue to provide "reliable, affordable and clean resources."

Lauren Tenney Denison, PPC's director of market policy and grid strategy, said BPA's transmission and connectivity "will be critical" for enabling a successful organized market in the Northwest.

"BPA is adjacent to over a dozen other balancing authority areas, which are all also considering potential participation in Markets+ and other market opportunities," she told *RTO Insider*. "Their access to those market opportunities will be impacted by the availability of BPA's transmission to be utilized in that market."

Denison said BPA's 31 dams, with a nameplate capacity of 22 GW, could provide "considerable" value for any centralized market, but that its commitment to continue develop day-ahead options "signals an assurance from BPA and public power that they will work collaboratively with other entities in the region to find an integrated market option that will work for the region."

"This is particularly important given the Northwest's previous struggles with establishing organized markets," Denison said. "BPA's role as a federal power administration with statutory commitments can create challenges to the agency participating in organized markets. This statement … demonstrates a commitment to work through these issues."

SPP welcomed the news.

"Over the last several months, SPP has been encouraged by the level of engagement among utilities like Bonneville Power Administration, plus public interest groups, state commissions and others interested in seeing Markets+ become a reality," CEO Barbara Sugg said in a *statement*. "With their input on the challenges and opportunities of ensuring electric reliability in the West, and our experience designing, building and administering electricity markets, we're confident we can deliver a market that brings tremendous value to a new part of the country."

SPP is preparing to publish in November a service offering for Markets+, a conceptual bundle of services that would centralize day-ahead and real-time unit commitment and dispatch and provide hurdle-free transmission service. Staff say that the offering would provide a voluntary, incremental opportunity to realize "significant" benefits for those utilities that aren't ready to pursue full RTO membership.

SPP has been working since last year with Western stakeholders to develop proposed service offerings, *transmission availability and market design*, and *governance structure*. Staff have held three in-person development sessions with the region's stakeholders, most recently this month in Portland, Ore. It plans a fourth in-person session in November in Phoenix. (See *SPP Continues to Build on Markets+ Offering*.) ■

CAISO/West News

CPUC to Delay Net Metering Decision for a Year

By Hudson Sangree

| Sunwatt Solar

The California Public Utilities Commission is poised to delay enacting controversial changes to net energy metering (NEM) for another year, saying it needs more time to consider revisions to how the state compensates owners of rooftop solar for electricity sent to the grid.

The current Aug. 27 deadline in the *proceeding* does not give the CPUC or the public enough time to review the mass of comments it has received on the changes or to vet alternatives, the commission said in a proposed decision Aug. 15.

"Accordingly, it is necessary to extend the deadline by one year to allow adequate time to address the remaining issues of this proceeding," Administrative Law Judge Kelly Hymes wrote in the proposed order, which the CPUC will likely take up at its next voting meeting this Thursday.

The one-year delay, to Aug. 27, 2023, is the latest postponement of California's efforts to reduce the generous credits it gives to rooftop solar owners who export surplus electricity. Currently, those customers receive bill offsets at full retail electricity rates, which are far more than the current costs of utility-scale solar.

A proposed decision in December set off a storm of public criticism by recommending up to an 80% credit reduction while adding an $8/kW monthly grid participation charge (GPC) to customers' bills. (See *California PUC Proposes New Net Metering Plan*.)

Opponents, led by the solar industry, have argued such a plan would decimate rooftop solar adoption. The NEM credits have made California the nation's rooftop solar leader, with more than 1.3 million installations, they contend.

Proponents of change, including the state's large investor-owned utilities, argue utility-scale solar is more cost-effective and can serve far more consumers.

The CPUC said in its proposed decision in December that the current scheme unfairly shifts costs from homeowners who can afford rooftop solar to those who cannot.

It "negatively impacts nonparticipating customers, is not cost-effective and disproportionately harms low-income ratepayers," Hymes wrote.

Utilities estimated that $4 billion in costs would be shifted this year from ratepayers with rooftop solar to those without it.

The outpouring of criticism over the December proposal led the CPUC to postpone an expected decision in January, as the commission's new president, Alice Reynolds, took the lead on the proceeding.

In May, Hymes asked parties to comment on *questions* she posed regarding possible alternatives.

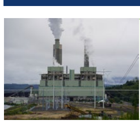
The judge's questions focused on a "glide path" to gradually transition rooftop solar owners from the generous benefits they now receive, and non-bypassable charges for solar owners based on their gross energy consumption, including use of the solar energy they generate.

A voluminous response to the judge's questions came from industry groups and environmental advocates, among others.

In comments last week, ClearView Energy Partners said it believed the latest delay signals the likelihood that the CPUC will eventually issue a scaled-back proposal next year.

"We continue to think final reforms are likely to be more modest than those offered in the [December proposed decision]," the firm said. "We think the glide path and the GPC are most susceptible to changes." ■

West news from our other channels



Wash. High Court Shuts Down Cap-and-trade Challenge NetZero Insider

Nev. Petition Seeks to Halt Utility Installation of LED Streetlights NetZero Insider

West Coast States Ask FERC to Deny Gas Pipeline Expansion NetZero Insider

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

CAISO Updates EDAM Straw Proposal

Schedules Stakeholder Meetings in Coming Weeks

By Hudson Sangree

CAISO issued a revised straw proposal last week for its planned day-ahead expansion of the Western Energy Imbalance Market, currently a real-time market that covers large portions of 10 states and one Canadian province.

The updated *proposal*, released Aug. 16, adds provisions on transmission commitment, resource sufficiency and firm energy contracts following a series of technical workshops and stakeholder meetings to iron out differences on the more difficult issues.

"This revised straw proposal for the extended day-ahead market (EDAM) reflects significant stakeholder input and design changes from the initial April 28, 2022, straw proposal," the ISO said. (See *CAISO Issues EDAM Straw Proposal for the West*.)

Among the major changes are refinements to the EDAM's proposed transmission commitment framework.

The initial *straw proposal* stated that unsold, firm available transfer capability (ATC) should be offered by EDAM participants to support transfers between balancing authority areas (BAAs) in the West.

An EDAM entity would be expected to "make available all remaining unsold firm ATC at an intertie with an adjoining EDAM BAA" by 10 a.m. in the day-ahead market and to stop open-access transmission tariff sales of firm ATC at the intertie between 10 a.m. and 1 p.m. while the day-ahead market was running, it said.

Stakeholders and the ISO, however, did not settle on some specifics of the plan.

The revised straw proposal says that "unsold transmission by the transmission provider will be made available to the market hurdle-free. Transmission customers can voluntarily release transmission rights for EDAM optimization, and the ISO will allocate transfer revenue associated with those rights directly to the transmission customer."

"The design also includes a proposed mechanism for transmission providers to recover potential foregone transmission revenues resulting from their participation in EDAM. This seeks to keep transmission providers as whole as possible from a transmission revenue recovery perspective."

EDAM participants would have to make unsold transmission capacity available in the day-ahead market. | *© RTO Insider LLC*

Resource Sufficiency

The proposal for a resource sufficiency evaluation (RSE) in the EDAM was left partially incomplete in April. The RSE test is intended to keep participants from leaning on the market for internal capacity needs, but consequences for failing the test — one of the most controversial issues in the EDAM stakeholder process so far — were not delineated in the first straw proposal.

Stakeholders had discussed financial penalties and transfer limits but did not reach agreement.

"Although there was no consensus regarding a particular approach, stakeholders generally preferred some form of financial consequence for failure, rather than a complete freezing of transfers in the day-ahead time frame, which could be detrimental to reliability," the straw proposal said.

After multiple technical workshops, the revised straw proposal "focuses on an administrative surcharge[s] under all conditions to incentivize meeting the RSE. It also introduces mechanisms to address ISO [load-serving entities'] concerns regarding their discretion to manage supply above what the ISO needs to meet its RSE to better manage grid reliability challenges if conditions change between day-ahead and real-time."

Firm Energy Contracts

The revised proposal also introduced a "tagging mechanism," a means of electronically monitoring and recording an energy transaction, for firm energy contracts.

In a firm energy contract, the "supplier takes on the obligation to deliver the generation and make the necessary transmission arrangements" to get the supply to the purchasing or sink BAA, but "neither the source of the generation (or source BAA), nor the transmission path is known by the time of the day-ahead market (10 a.m.) when bids into the market are due." That information "becomes known later," it said.

"In a day-ahead market context, the lack of source specificity and transmission path pose a challenge in modeling the expected flows across the system," it said. "Nevertheless, the ISO recognizes these arrangements are an

CAISO/West News

important source of supply in the West today."

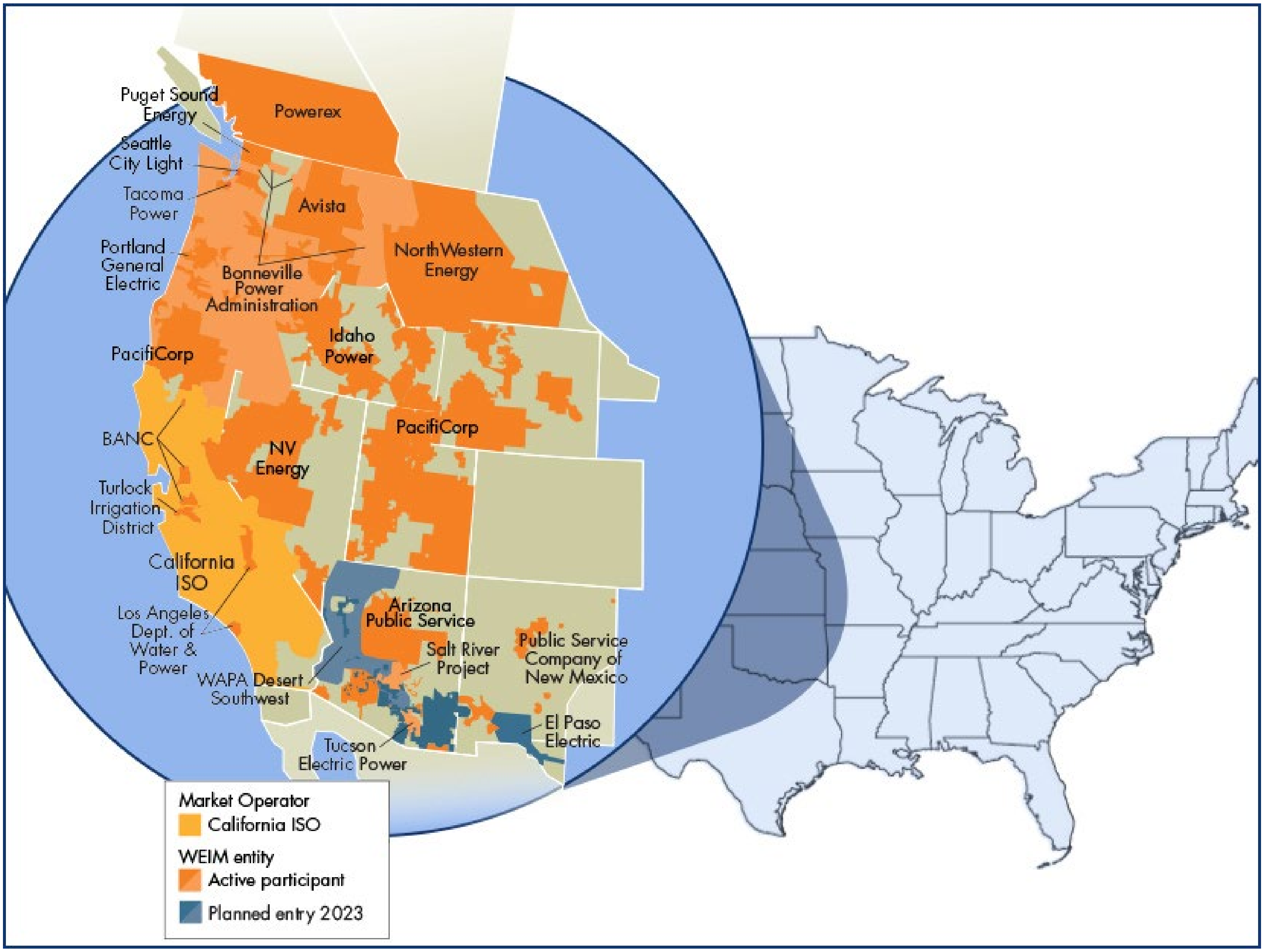
Uncertainties about source and transmission require a tagging mechanism to "provide greater confidence in these arrangements," it said. "Intertie bids at the ISO border that are under contract to an ISO LSE or otherwise have a contract under the ISO tariff will be eligible for the ISO RSE and will also be subject to the tagging requirements."

Additional Features

Other provisions in the revised straw proposal include:

- a convergence bidding proposal that maintains a one-year transition period to convergence bidding for EDAM entities. "After that first year, the EDAM entity will have the option to adopt convergence bidding in their area or elect for another year of transition," it says. "After the second transition year, an EDAM entity would be expected to transition to convergence bidding, absent any findings that doing so poses adverse outcomes."
- an equal sharing of transfer revenues "across all interfaces between EDAM BAAs, subject to commercial arrangements that may require exceptions. In addition, in instances where congestion arises from an internal intertie constraint enforced within a BAA, the ISO will allocate the congestion revenue fully to the BAA where the constraint is modeled."
- a greenhouse gas accounting and reporting protocol in which the EDAM will start with a "resource specific approach to GHG accounting because this is a known, implementable approach that California ISO builds upon and enhances the current WEIM framework. Throughout this initiative, however, we will continue to vet and evaluate the alternate approaches."
- an EDAM administrative fee arrangement under which a "systems operations charge will be applied to metered flows in megawatt-hours of supply and demand. This is a similar assessment to the grid management charge system operations charge."

Meetings to discuss the revised straw proposal are scheduled for Aug. 29 (virtual only) and Sept. 7-8 (virtual and in person.) The EDAM stakeholder initiative *webpage* contains additional information on the upcoming meetings and anticipated EDAM development milestones. ■



The EDAM could extend across much of the territory now included in the WEIM's real-time market. | *CAISO*

ERCOT News

ERCOT Names NiSource's Vegas as New CEO

Texas Grid Operator Gets 'Leader We've Been Looking for,' Board Chair Says

By Tom Kleckner

AUSTIN, Texas — ERCOT announced last week that it has selected Pablo Vegas, a senior executive with Indiana-based utility NiSource, as its next CEO.


Pablo Vegas, NiSource | *NiSource*

Vegas, currently an executive vice president with the company and group president of NiSource Utilities, will join the Texas grid operator on Oct. 1. He will replace interim CEO Brad Jones, whose 90-day temporary gig has stretched into a 16-month assignment.

The announcement came during the Board of Directors' bimonthly meeting Aug. 16 and was quickly ratified by the Texas Public Utility Commission.

Vegas will be expected to guide ERCOT as it continues to make changes following the February 2021 winter storm that nearly brought the Texas Interconnection to its knees. A massive loss of generation led to dayslong outages that resulted in hundreds of deaths and billions of dollars in damages.

"With Pablo, we're getting the leader we've been looking for: extensive experience with regulated utilities; a demonstrated record of managing a system of diverse energy resources; and most importantly, unwavering commitment to reliability," board Chair Paul Foster said after breaking the news. "With this unanimous vote, it is clear that this board believes we have found an exceptional executive who can successfully lead this organization."

The board approved Vegas' selection and compensation package during an executive session Aug. 15. The announcement was made at the start of the board meeting the next day as it became apparent to the directors that the news had been leaking out and represented "a risk to the [employment] agreement." One market insider said they had first heard Vegas' name early this month.

NiSource is one of the largest fully regulated utility companies in the U.S., serving approximately 3.2 million natural gas customers and 500,000 electric customers across six states through its Columbia Gas and Northern Indiana Public Service Co. brands.

Vegas, who was only promoted to his present position on July 1, signed his contract Aug. 15. He was not in Austin for the board meeting or available for comment. ERCOT directors and staff declined to comment.

"I'm excited to return to Texas both personally and professionally," Vegas said in a *statement*. "This is a once-in-a-lifetime opportunity to lead an exceptional organization of people and make a positive impact on millions of Texans."

Before joining NiSource in 2016, Vegas spent 11 years with American Electric Power. He served as president and COO of both AEP Texas, for two years, and AEP Ohio. Vegas has a bachelor's degree in mechanical engineering from the University of Michigan and held senior leadership positions with Andersen Consulting and other firms before joining the utility industry.

Judith Talavera, who currently holds Vegas' titles for AEP Texas, said his time in the state "gives him a unique understanding" about the ERCOT system's strengths and weaknesses.

"His experience in Texas and his leadership positions at AEP Ohio and NiSource will serve him well in his new role as ERCOT CEO. We look forward to working with him," Talavera said in an email to *RTO Insider*.

"It doesn't hurt that this isn't his first rodeo in Texas," Foster told the board. "Pablo knows our current market; he knows the incredible progress we've made in the last year implementing landmark reforms; and he knows how to turn the challenges we face into opportunities to strengthen the competitive market in Texas."

"He has been an invaluable member of our leadership team, and I along with the entire NiSource community will miss working with Pablo, and we wish him the best in his new role at ERCOT," NiSource CEO Lloyd Yates said in a *press release*.

Vegas' hiring comes after several sources told a Texas newspaper that Gov. Greg Abbott stepped in to reject an earlier selection of former CAISO CEO Steve Berberich. (See *ERCOT Could Name New CEO this Week*.)

According to his *employment contract*, Vegas will earn a base salary of $990,000 and a one-time lump sum payment of $247,500 on or before Dec. 31. He will also receive make-whole payments of $6.68 million through 2027, when his contract ends. Beginning next year, Vegas will be eligible for incentive payments that could equal his base salary, assuming he meets key performance indicators.

Former ERCOT CEO Bill Magness, who was fired in March 2021 following the winter storm, disclosed during testimony before the Texas Legislature last year that his annual salary was $803,000. Jones' *annual salary* is $500,000, and he is a due a one-time lump sum of $169,640 when he receives his final paycheck.

South Texas Electric Cooperative's Clif Lange, chair of ERCOT's Technical Advisory Committee, said the group looks forward to working closely with Vegas when he takes over.

"He faces some very big challenges as he transitions into the role, with a number of initiatives already started but with many still ahead," he said, referring to the second phase of ERCOT's market design. "I'm optimistic that he'll be able to lead ERCOT successfully in implementing those."

Director Bill Flores led the selection committee in what was termed an "exhaustive" nationwide search. He said the group identified 107 candidates and interviewed 21.

The directors, ERCOT staff and stakeholders saluted Jones with a standing ovation after the announcement was made.

"Twenty-six million Texans owe you a real debt of gratitude for everything you and the team have done to persevere through the challenges faced with record heat and cold winters," Flores said.

A smiling Jones pointed to his grin as he greeted well-wishers during the meeting's first break. He will spend October helping Vegas transition into his new position before resuming a retirement that was interrupted by the winter storm.

"Brad stepped in as our interim CEO during a very challenging time and was unquestionably the leader ERCOT needed at a most difficult time," Foster said. "He's also stayed much longer than originally anticipated."

"Hopefully, his next endeavor includes an enjoyable and relaxing retirement, although I will bet that he will remain engaged in the electric industry. It's in his blood," Lange said. "He's faced a monumental task in overseeing a significant overhaul of ERCOT's priorities, and while it's not always been popular, he's been very successful in navigating those changes." ■

ERCOT News

ERCOT Board Gives Southern Cross Project a Boost

Skelly's Grid United Eyes HVDC Intertie in West Texas

By Tom Kleckner

AUSTIN, Texas — ERCOT's Board of Directors last week added their endorsement of the Southern Cross Transmission (SCT) merchant project's last three regulatory *directives*, imposed to determine whether it can safely interconnect with the Texas grid.

The project, a long-haul HVDC transmission line that would connect the Texas Interconnection with systems in the SERC Reliability region, has been under regulatory review for seven years. It will be capable of carrying 2 GW of power between Texas and SERC over a 400-mile, double-circuit 345-kV line.

More important to the Texas Public Utility Commission and the state's leadership, SCT has FERC approval and a waiver from its jurisdiction, keeping ERCOT free of federal overview and maintaining its status as an island unto itself.

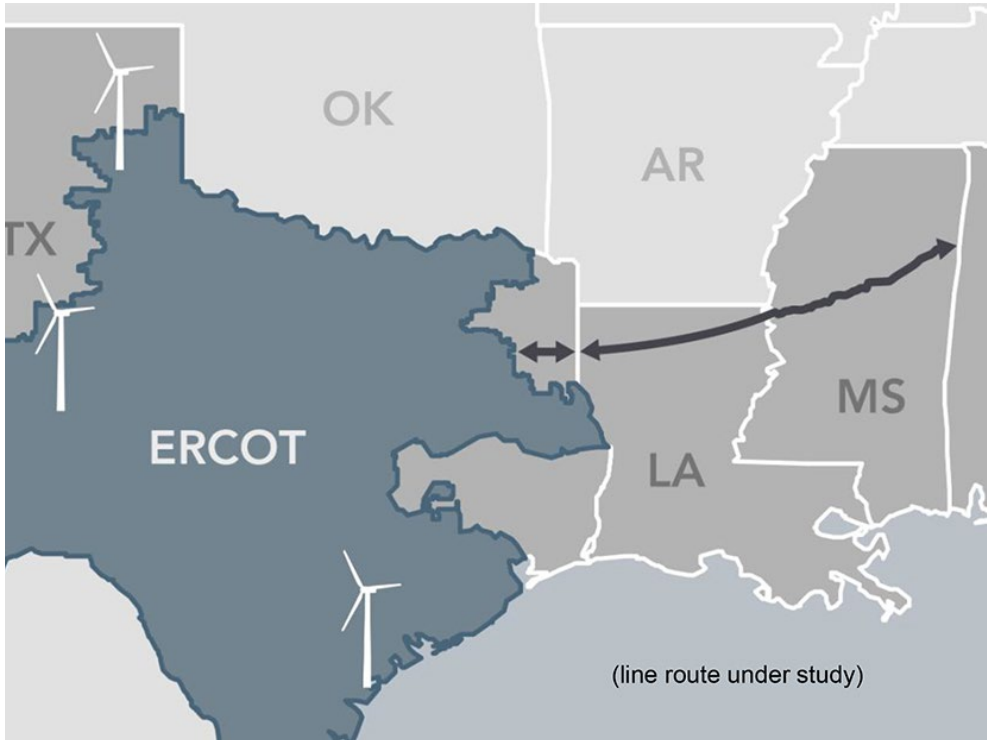
The project's developer, Pattern Energy, called the board's Aug. 16 action an "important milestone" and thanked ERCOT staff for completing the studies ordered by the PUC.

"Today's action … represent[s] the completion of all studies ordered by the [PUC] to confirm the Project can be reliably interconnected with the ERCOT grid," said Glen Hodges, Pattern's vice president of business development. "Once completed, Southern Cross Transmission will provide substantial reliability benefits to all Texans who rely on the ERCOT grid, providing access to alternate sources of reliable and affordable power during emergencies such as Winter Storm Uri and the recent extreme heat-related demands on the grid."

"For the last five years or so, we've been resolving the directives and getting this project ship shape," ERCOT assistant counsel Nathan Bigbee said. "These last three [directives] get closure and regulatory certainty to move forward with this project."

The directives are:

- *1*: creates a new market participant type, "Direct Current Tie Operator." A nodal protocol revision request (*NPRR857*) approved in 2018 created the DCTO role, but SCT has told the grid operator it does not plan to join an appropriate market segment at this time. That led staff to conclude no bylaw revisions are needed yet.



The Southern Cross Transmission project will run more than 400 miles from East Texas into SERC. | *Pattern Energy*

- *11*: finds that costs identified by the PUC have been appropriately addressed by resolving each of the commission's 14 directives and through a memorandum of understanding between ERCOT and SCT. Under the agreement, Pattern will fund the projects needed to accommodate the tie; it has already been compensating ERCOT monthly for related costs.
- *12*: determines that costs associated with DC tie exports have been sufficiently addressed by the other directives' resolution and that no further revision to any cost-allocation mechanism is necessary.

Bigbee told directors that SCT will affect voltage on the eastern side of ERCOT's system. He said an NPRR will need to be drafted to ensure the project provides voltage support in the region.

The PUC asked ERCOT to address *14 directives* and determine whether DC ties should be economically dispatched or subject to a congestion-management plan. Only Directive 2, which requires the grid operator to enter a coordination agreement with the balancing authority on the project's eastern end, has not been completed. The project's developers have said that directive is not necessary to the commission's review and can be closed later.

Garland Power & Light owns the project's western endpoint and holds a certificate of convenience and necessity granted by the PUC in 2017. The project developers have not yet announced an eastern endpoint.

PUC Commissioner Jimmy Glotfelty has taken the agency's lead on SCT and *filed* a memo in January that said it's time that the commission and ERCOT "close a chapter" on the project and allow it to "stand or fail on its own economic merits." He believes the review can be finished by the end of October (*46304*). (See *Texas Regulators Boost Southern Cross Project*.)

The Technical Advisory Committee earlier endorsed the directives in June. (See "SCT Project Moves Closer to Reality," *ERCOT Technical Advisory Committee Briefs: June 27, 2022*.)

SCT supporters got a minor scare when Board Chair Paul Foster mistakenly tried to bring the meeting to an early end just before the project was due to be discussed.

"So that concludes our agenda, and we are now

ERCOT News

adjourned. Thank you all," Foster began before he was quickly interrupted.

"No, no. Sorry … we have a few more voting items," ERCOT General Counsel Chad Seely said, keeping the meeting on track.

Grid United Files CCN in West Texas

A second HVDC merchant project is taking shape on the western side of ERCOT's system, where Grid United, led by a familiar face, has *applied* with the PUC for a CCN (*53758*).

Grid United's Pecos West project consists of two proposed 1,500-MW HVDC converter stations in ERCOT's West Texas region (near Bakersfield) and El Paso in WECC territory. The project would bridge two Texas markets with 250 to 300 miles of an HVDC intertie line.

The company was founded last year by Michael Skelly, who serves as its CEO. Grid United says it seeks to tie regional grids together to improve resilience, increase the reliability of cheap renewable energy and reduce health hazards from fossil fuel energy production.

Skelly was also behind Clean Line Energy Partners, another long-haul developer that was working on five projects at one time, capable of carrying 16.5 GW of energy. Faced with political, regulatory and landowner opposition, Clean Line eventually was forced to sell most of its projects and was out of business by 2019. (See *Out of the Game, Skelly Still High on Wind Energy*.)

"Texas is blessed with an evolving and abundant power supply. … However, this abundance presents unique challenges, including volatile commodity prices and reliability concerns due to market structures that were not designed for the evolving energy mix the Texas grid is faced with today," Skelly said in testimony *filed* with the PUC.

"These challenges, which are especially acute in West Texas where renewable generation has proliferated, will only increase over the decades to come unless steps are taken proactively to address them," he said.

Grid United's Texas subsidiary is only seeking approval of the interconnection and will file for full CCN rights once the interconnection is approved. The company says it will obtain all necessary FERC approvals to maintain ERCOT's jurisdictional status quo.

Michael Skelly, Grid United | © *RTO Insider LLC*

Former FERC and Texas PUC Chair Pat Wood says the federal commission has policies that would protect the Texas Interconnection from federal interference if it were to strengthen its existing connections to the two national grids.

"We have the ability to build gates to the outside and not become vassals of another king," Wood *said* during a panel discussion earlier this year. "We [would still be] in charge of our own grid — and that was built into the federal law." ■

ERCOT News

ERCOT Board of Directors Briefs

Board Agrees to Lower Unsecured Credit Limit for Counterparties

AUSTIN, Texas — ERCOT's Board of Directors last week unanimously approved a nodal protocol revision request (*NPRR1112*), tabled since April, that will lower unsecured credit limits from $50 million to $30 million.

In doing so, the board sided with stakeholders over staff, who want to eliminate the limit. If it did so, ERCOT would be the only grid operator without unsecured credit limits between counterparties in its market; the others all have $50 million limits, according to staff's findings.

ERCOT currently has $1.36 billion in outstanding unsecured credit. Reducing the limit to $30 million will reduce the amount to about $1.1 billion.

Kenan Ögelman, the grid operator's vice president of commercial operations, told the board during its Aug. 16 meeting that staff continue to recommend eliminating unsecured credit. Using unsecured credit moves credit costs from those receiving unsecured credit to the rest of the market and ultimately load, he said.

Ögelman also apologized for staff's error during the June board meeting, when he said lowering the credit limit to zero would eliminate about $1 billion in the outstanding amount. "Actually, it was more in the $300 million range," he said. (See "Maintenance Outage Scheduling Methodology Approved," *ERCOT Board of Directors Briefs: June 21, 2022*.)

Darrell Cline, general manager for Garland Power & Light, advocated the Technical Advisory Committee's position before the board. He said other "more appropriate" vehicles exist to target credit risk, pointing to *NPRR1067*, which sets market entry qualifications, continued participation requirements and credit risk assessments. The measure has been open since January 2021.

"Staff continues to believe that reducing unsecure credit is best for ERCOT. No other sophisticated markets allow for that," interim CEO Brad Jones said, ticking off the Intercontinental Exchange, New York Stock Exchange and New York Mercantile Exchange as examples. "The very fact that the other" grid operators allow it is not "a compelling argument that we should do it as well. We know there's a risk there." He offered NPRR1067 as an opportunity to revisit the discussion.

The measure now goes before the Texas Public Utility Commission; it would become effective Oct. 1, 2023, allowing municipal utilities with fiscal years that end Sept. 30 to first close their books.

TAC earlier rejected staff's recommendation in April. ERCOT appealed the decision to the board, only to see it tabled that same month with a request for information on other grid operators' unsecured credit practices. (See "ERCOT's Credit Limits Align with Others," *ERCOT Technical Advisory Committee Briefs: May 25, 2022*.)

ERCOT directors and stakeholders during the August board meetingt | *© RTO Insider LLC*

Staff Studying 17 GW of Crypto Load

ERCOT staff told directors that they are studying more than 17 GW of crypto mining load as it prepares its mid- and long-term forecasts.

Alluding to the Texas bitcoin rush, Jeff Billo, director of operations planning, said crypto load has grown since the studies began.

"Not all of that will be constructed, but the challenge is how much will be there in three to four years," he said. "Midterm, it's a challenge because [crypto load] is very price-responsive, more price-responsive than we have seen with other demand response in the past."

ERCOT's midterm load forecast uses two vendor models and five staff models to take an hourly look seven days into the future. It is updated hourly.

The long-term forecast uses one staff-developed model to provide an hourly forecast 10 to 30 years out and is updated annually.

Crypto miners have been drawn to Texas by its relatively low wholesale energy prices and because ERCOT pays industrial users to shut down during tight conditions. Their data farms typically use enormous amounts of power.

Billo said the amount of crypto load is not "constructive" to ERCOT's planning models. He said staff are working with stakeholders to understand how much of it will show up. "We have to improve our processes to understand that behavior and build that into our model."

The 2023 load forecast will be included in ERCOT's December capacity, demand and reserves report, which projects 10 years into the future.

Directors Exert Control over Bylaws

The board's Human Resources and Governance (HR&G) Committee agreed during its Aug. 15 meeting to modify ERCOT's governing bylaws and other organizational documents, moving the authority for making future bylaw changes from corporate members to the direc-

ERCOT News

tors and taking away members' ability to veto the revisions.

Director Peggy Heeg, the committee's chair, said that *legislation* passed last year after the February winter storm laid out "checks and balances" for ERCOT's governance. She said it also required the PUC to approve all bylaws and their changes.

"While legislators and the governor clearly intended this board to have control over ERCOT, they were also very clear that corporate members are also valued contributors … and should have a voice in the bylaw-amendment process," she said.

"It's very clear from [the legislation] that this is what we're directed to do," board Chair Paul Foster said in agreeing with Heeg.

The committee urged the board to engage with members as it modifies the bylaws. Heeg also proposed the board to "move forward deliberately" in revising TAC's reporting relationship and its structure.

"The market participants and corporate members have a very valuable place in contributing to this board," Heeg said.

Under the suggested changes, members will still be able to propose amendments or comment on those under consideration. Board Vice Chair Bill Flores also said TAC will keep a seat at the table, "where it's most valuable."

ERCOT's legal staff said it will take the board's input and produce a redlined version of bylaw changes that can be shared with members. Their goal is to produce a final document by year-end for approval by the board and PUC.

Board Approves Tx Projects

The board approved two transmission projects with a combined capital cost of more than $760 million previously endorsed by TAC and recommended by the Regional Planning Group. (See "Members Endorse Two Tier 1 Transmission Projects," *ERCOT Technical Advisory Committee Briefs: July 27, 2022*.)

The Bearkat-North McCamey-Sand Lake project in West Texas — consisting of two double-circuit, 345-kV transmission lines totaling about 165 miles — has an estimated cost of $477.6 million in 2021 dollars, up from $371 million in 2019 dollars. Oncor, Lower Colorado River Authority Transmission Services and Wind Energy Transmission Texas expect to complete the project in June 2026.

The Roanoke upgrade project north of the Dallas-Fort Worth area involves 7 miles of

ERCOT's Kenan Ögelman (left) listens as Garland Power & Light's Darrell Cline lays out TAC's position on unsecured credit. | © *RTO Insider LLC*

138-kV lines, 26 miles of 345-kV lines, four 345/138-kV transformers and five 138-kV low-voltage buses. Oncor, the incumbent transmission service provider, expects to complete the upgrades by May 2025 at a projected capital cost of $285.9 million.

The projects are classified as Tier I builds because their costs exceed a $100 million threshold. Their status requires they receive TAC endorsement and the Board of Directors' approval.

The directors also approved ERCOT's proposal to change the reliability unit commitment cost-scaling parameter from 20% to 100%, effective Sept. 1. The grid operator's greater use of the RUC process under its conservative operations posture this year has led to operators making many of their decisions outside of the process's economic-based recommendations, leading to inefficient commitments.

The board also approved eight NPRRs, two other binding requests (OBDRRs), single revisions to the Planning Guide (PGRR) and the Retail Market Guide (RMGRR), and a system change request (SCR):

- *NPRR1085*: changes the physical responsive capability calculation and dispatch's validity by requiring quicker updates from qualified scheduling entities (QSEs) on telemetered resource status, high sustained limit and other relevant information.
- *NPRR1131*: changes controllable load resource's participation in non-spinning reserve from offline to online non-spin. The change sets a bid floor of $75/MWh, equivalent to generation resources' offer floor when providing online non-spin. If a QSE also assigns responsive reserve (RRS) and/or regulation up service to a controllable load resource that has been assigned non-spin, the sum of RRS, reg-up and non-spin ancillary service resource responsibilities will be assigned a $75/MWh offer floor.
- *NPRR1133*: clarifies the responsibilities of DC tie facility owners and operators for reporting DC tie model data.
- *NPRR1134*: removes references to first available switch date (FASD) after recent mass transition/provider of last resort events indicated ERCOT's use of FASD when processing switch transactions created an unintended negative experience for customers being transitioned from a bankrupt retailer.
- *NPRR1135*: modifies the definition of real-time generation resources with an offline non-spin (OFFNS) schedule to allow non-zero values for the billing determinant only if the resource is offline when it telemetered OFFNS. This ensures an accurate settlement when an online resource erroneously telemeters OFFNS.
- *NPRR1136*: adds clarifying language to the logic in place as fast frequency response is developed to ensure a QSE does not replace a regulation service with fast-responding regulation service.
- *NPRR1137*: replaces the annual requirement to review the OBD list with a four-year review cycle.
- *NPRR1142*: increases emergency response service's (ERS) annual budget from $50 million to $75 million and gives ERCOT the ability to contract ERS for up to 24 hours in a standard contract term.
- *OBDRR040*: removes the controllable load resource providing non-spin schedules and regulation service schedules from the capacity calculations to align with NPRR1131.
- *OBDRR042*: increases the ERS annual budget and makes other administrative changes to the program.
- *PGRR101*: clarifies that a DC tie's owner will provide the appropriate dynamic model data to its tie operator, which will then provide the data to ERCOT.
- *RMGRR168*: synchronizes ERCOT's role and responsibilities with current market transactional solutions upon the removal of the "out-of-cycle" switch term and market process.
- *SCR822*: creates a new daily integration report and dashboard for energy storage resources similar to the current wind and solar integration reports and dashboards.

— Tom Kleckner

ISO-NE News

ISO-NE Wants to Hike its Budget by 10% in 2023

By Sam Mintz

ISO-NE is proposing a roughly 10% increase in its operating budget for 2023 and the addition of more than 50 employees over the next two years as it looks to reshape the region's electricity markets.

According to a *presentation* by ISO-NE CFO Robert Ludlow to NEPOOL's Budget and Finance Subcommittee on Aug. 11, the grid operator's proposed operating budget of $209 million is a more than $20 million boost (before depreciation) over that of 2022 and would require $9.475 million more in revenue.

Part of that budget bump is that the grid operator plans to add 52 full-time equivalent positions by 2024, 32 in 2023 and 20 the next year. The largest group of new jobs would be nine additions in market development, as the RTO continues to try to move forward on complex work to update the Forward Capacity Market, including with resource capacity accreditation and new day-ahead ancillary services.

ISO-NE is also proposing to add eight positions to its information and cybersecurity office, five for system planning, and two each in participant relations, advanced technology solutions, system operations and market administration, external affairs and HR.

And it's budgeting more — $8.4 million in total — for employee raises and benefit increases, plus recruiting, retention and succession planning.

The grid operator's 2023 capital budget is $33.5 million, a $7 million increase over those of the last few years, driven by the next generation markets project, other market and reliability initiatives, cybersecurity enhancements, and information technology and infrastructure replacements.

ISO-NE is proposing a budget increase for 2023. | *ISO-NE*

The budget finds $3.4 million in savings, including lower salary rates from turnover and retirements, less building maintenance, fewer software licensing costs and more.

Because ISO-NE is funded by fees from market participants and ratepayers, the budget is scrutinized closely by consumer advocates and state officials. The RTO is currently in the process of running the budget by state agencies and planning to ask for a NEPOOL Participants Committee vote in October, shortly followed by a Board of Directors vote and FERC filing. ■

ISO-NE News

NE States Moving (Slowly) Toward Regional Clean Energy Market

By Sam Mintz

After ISO-NE issued a *comprehensive study* in April looking at possible regional decarbonization solutions, there was hope around the region's energy and environmental sectors that it would jumpstart the states into action.

Among the study's key findings was that the status quo — New England states largely continuing to individually, unilaterally advance their own decarbonization policies through procurements — would be more costly for the region than any of the modeled alternatives, including carbon pricing, a forward clean energy market (FCEM) or a hybrid of the two.

But the gears are turning slowly in the states, which one regulator compared to aircraft carriers chugging out to sea.

And the approaching gubernatorial elections may also have a paralyzing effect, pushing the earliest point for decisive action beyond November and into 2023.

In interviews with *RTO Insider*, three New England state energy officials defended their deliberative processes and urged patience from those who are pushing them to move faster.

"I think the thing I would emphasize is what a dynamic moment we're in, in terms of this longstanding question of harmonizing markets and decarbonization mandates," said Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection.

She pointed to FERC's recent approval of an ISO-NE plan to phase out the contentious minimum offer price rule, as well as the action in Washington over the past few weeks, culminating in President Biden signing the landmark Inflation Reduction Act, with new incentives and support for all sorts of clean energy technology.

"I know that there's a lot of eagerness from stakeholders to hear the states' views on next steps," Dykes said. "At the same time, there's a lot going on in the current moment that needs to be taken into account with which solutions make the most sense."

June Tierney, commissioner of the Vermont Department of Public Service, said that regulators are tasked with taking a comprehensive view and carefully working through complex issues.

"When the Navy deploys for a military action, they don't just all hop on the carrier and go to battle. They're accompanied by a flotilla, and a lot of the flotilla are speedboats, things that can maneuver more nimbly and move out ahead and show the way. And then comes the carrier in the wake," Tierney said in an interview.

"My point is, there are many stakeholders in this process who do move more quickly, more nimbly. They help pull us along. And we're the aircraft carriers, the six states. We move slowly but steadily," Tierney said.

Those pulls and pushes have come from environmental advocates and the renewable industry, but also from generators more broadly.

"The inaction of the moment is a choice in and of itself to maintain the status quo," said Dan Dolan, president of the New England Power Generators Association in an email to *t*. "That is the one pathway that the states, generators and ISO-NE all agreed was the worst possible outcome."

Dolan urged the states to forge ahead and not fear political vulnerability.

"The reality is that with all six states in the midst of gubernatorial elections, a final decision is likely going to have to wait," he said. "While I respect the politically awkward timing of the moment, I sincerely hope the next several months are not lost to the campaign season, and that important work can still progress."

Tierney said that it is progressing.

"We're all showing up to our meetings. We're all having the conversations," she said. "What we're doing is trying to figure out what can we do while we await election results."

Wrestling with FCEM Governance Questions

While a straight up price on carbon has support in large swaths of the region's energy industry and inside ISO-NE, the states have uniformly said that its political challenges make carbon pricing a nonstarter.

New England states are working on a clean energy market to incentivize the build out of more renewables. | *Shutterstock*

Instead, they're eyeing an FCEM, a centralized auction in which sellers (producing energy through means including wind, solar, nuclear, hydro) and buyers (states, cities, companies, retailers, utilities and more) would exchange clean energy credits.

An FCEM could be enacted on its own or in a hybrid configuration along with a slimmed down carbon pricing mechanism. It could bring New England's clean energy procurement more into concert, instead of the states relying on individual contracts.

But because an FCEM would be a brand new market structure, there are a host of governance and structural questions that the states and ISO-NE would have to hash out.

"Would implementation of these measures be something that would be supported within a FERC-jurisdictional tariff advanced by ISO-NE, or would they require individual state legislatures to authorize them?" Dykes said. "These are important questions, and we're taking our time to think through it and looking at the best model."

ISO-NE CEO Gordon van Welie has warned that FERC might see an FCEM as discriminatory and likely to lead to litigation. (See *NE States, ISO-NE Start to Wrestle with Next Steps on Pathways*.)

But Tierney said that her observations of the current FERC commissioners suggest otherwise.

"Sometimes I think what has been missing here is that FERC has been very intent on ensuring that nobody gets out in front of the states," Tierney said. "I am going to be bullish on how FERC might respond to an FCEM mechanism that has the support of the states."

Massachusetts is working on developing a proposed framework for an FCEM, which officials there hope can be a jumping-off point for regional discussions in the next few months.

"Massachusetts believes an appropriate next step is to develop a design structure that addresses detailed mechanics along with defining governance and state involvement," Patrick Woodcock, commissioner of the state's Department of Energy Resources, said in a statement to *RTO Insider*. "To move away from the state-based procurement process into a regional framework will require full confidence from the states in their role in decision-making and alignment with state laws." ■

MISO Rejects Call for Penalty-free Queue Exits

By Amanda Durish Cook

MISO is resisting clean-energy developers' calls to allow penalty-free generator interconnection queue withdrawals for certain projects bogged down by SPP's affected system studies.

The grid operator contends that respite for some projects is unnecessary because it already has provisions to extend commercial operation dates, and it offers chances at penalty-free withdrawals.

"Interconnection customers are already afforded a three-year grace period from the documented [commercial operation date] to bring a resource commercial," Ryan Westphal, Interconnection Process Working Group liaison, told stakeholders Aug. 15 during an IPWG teleconference.

Westphal said MISO will also offer penalty-free exit after projects receive their affected system study results. However, projects that already have signed a generator interconnection agreement with MISO cannot back out without risking paid per-megawatt milestone fees.

In June, Clean Grid Alliance asked the RTO to consider penalty-free withdrawals or longer extensions for advanced-stage interconnection projects already in limbo while waiting on potentially expensive network upgrade costs from SPP's study results. (See *Clean Grid Asks MISO for Penalty-free IC Exits*.)

CGA's Rhonda Peters said upgrades from the affected system studies (AFS) can be staggering and upend once-promising generation projects.

MISO and SPP have rolled out a new, "first ready, first served" queue priority for generation projects that could affect system impact studies on the seams, affected-system studies and cost assignments for network upgrades. The initiative replaces the grid operators' previous practice of first studying projects with the earliest queue entry dates. That practice didn't account for a project's preparedness. (See *FERC OKs New Queue Priority for MISO, SPP Seams Studies*.)

Batches of projects that entered MISO's queue in 2018 and 2019 were left out of the new priority. Staff said those project cycles are destined for GIAs before the changes take effect.

Upon hearing CGA's pitch for free-and-clear withdrawals and extensions, staff expressed concerned that allowing the penalty-free exits could potentially harm lower-queued projects. MISO usually keeps departing interconnection customers' milestone fees to minimize the costs of network upgrades on lower-queued projects.

Peters argued that the AFS-assigned upgrades can go as high as $100 million, a figure no one initially expects.

"This is such an extreme level of uncertainty, and it's such a tough situation for these projects to be in," she said. "This is unprecedented. The level of uncertainty that these projects face is so extreme that no one could have ever predicted it."

Peters advocated again for a limited waiver for 2018 cycle projects affected by system impact studies.

| *Pattern Energy*

Staff pointed out that developers can always seek individual waivers of interconnection procedures through FERC.

Invenergy's Sophia Dossin said generation developers are in a "Russian roulette situation with these massive, project-killing upgrades."

Other stakeholders argued that SPP keeps delaying its final batches of system impact studies, making affected system upgrades even murkier. ■

MISO News

Entergy CEO Denault Stepping Down in 2023

By Amanda Durish Cook

Entergy on Wednesday announced that chairman and CEO Leo Denault will step down early next year after a decade at the utility's helm.

The Entergy board of directors has elected current CFO Drew Marsh to succeed Denault as CEO, effective Nov. 1, in an overlapping transfer of power. Denault will continue to lead the board as chairman until his retirement.

Entergy said the move is part of an "orderly and planned leadership succession process."

Denault, 62, has spent 23 years with Entergy, becoming an executive vice president and CFO in short order a few years after his arrival. He has served as chairman and CEO since 2013, when he took over for J. Wayne Leonard as Entergy transitioned into MISO membership. Denault and Leonard are Entergy's only two CEOs in the last 24 years; Leonard, who died in 2018, became CEO in 1998.

In a *press release*, Entergy's lead independent director Stuart Levenick said Denault has "strengthened the business and positioned Entergy well for the future." Levenick also said he's "confident that Drew will carry the torch and continue serving all of Entergy's stakeholders well by creating sustainable value today and for future generations."

Marsh, 50, joined Entergy in 1998, serving in several financial planning and strategy roles before becoming CFO in 2013. Kimberly Fontan will become Entergy's CFO; she has served as a senior vice president and chief accounting officer since 2019.

"I am both grateful and honored by the confidence the board has placed in me, and I'm honored to follow in my colleague and friend Leo Denault's footsteps," Marsh said. "I will uphold Entergy's values and the strategy that he has instilled in our leadership team."

Entergy New Orleans Power Station sign | *Pro Signs and Graphics*

Entergy CEO Leo Denault | *Entergy*

Denault said his transition comes at a "logical time," pointing out that Entergy recently successfully pulled off its "planned, multiyear strategy" to exit the merchant nuclear power business.

Entergy owned six merchant nuclear power plants when Denault began managing the company: FitzPatrick and two Indian Point units in New York; Vermont Yankee in Vermont; Pilgrim in Massachusetts; and Palisades in Michigan. All are now closed except for FitzPatrick, which Exelon now owns.

Entergy said Denault played a critical role during and after Hurricane Katrina's 2005 destruction, making sure the company's headquarters remained in New Orleans — where it is the city's only Fortune 500 company — and guiding Entergy New Orleans through bankruptcy proceedings after it lost nearly all of its customers in the storm's aftermath.

The utility also praised Denault for spearheading an accelerated goal to reach net-zero emissions by 2050 and "advancing climate resilience initiatives throughout communities in the Entergy region."

For years, Entergy has had a goal to invest about $1 billion annually in transmission capital projects for economic and system resilience reasons. In June, Entergy committed to a $25 billion, five-year capital plan to ramp up decarbonization efforts and to accelerate reinforcements to its Gulf Coast infrastructure to better protect it against future hurricane strikes. The plan includes adding more renewable energy and burying some distribution lines.

After Hurricane Ida darkened the coastal Louisiana grid for weeks last year, Entergy faced calls from climate change activists to harden its transmission and distribution system and make more investments in renewable energy. (See *Entergy Fends Off Calls for Tx, Solar, Microgrid Investment*.)

Entergy announced other leadership changes Wednesday.

Chris Bakken, currently executive vice president and chief nuclear officer, was named executive vice president of Entergy infrastructure. Entergy said Bakken will have oversight responsibility for both utility operations and nuclear operations.

Senior Vice President of Nuclear Corporate Services Kimberly Cook-Nelson was appointed executive vice president of nuclear operations and chief nuclear officer. The company said Cook-Nelson will be responsible for operations at Entergy's four remaining nuclear plants in in Arkansas, Louisiana and Mississippi. She will report to Bakken. ■

MISO News

MISO Pledges Review of On-hold Stakeholder Ideas

By Amanda Durish Cook

MISO is refreshing its longstanding "parking lot" of improvement ideas submitted to the grid operator, some of which have been in a holding pattern for the better part of a decade.

The RTO has conducted an internal review on how it handles issues relegated to the *parking lot* until MISO stakeholder committees deem it's time to reexamine them. Some stakeholders have said topics they've brought forward can languish on the list.

Alison Lane, stakeholder relations lead, said during a Steering Committee teleconference Wednesday that MISO will now refer to inactive recommendations and will commit to their biannual reviews, beginning in 2024.

Staff will go before its large stakeholder committee meetings with a review and cleanup of the suggested improvements, Lane said. MISO will keep the issues that advance its imperative reliability work or that can be handled within the next three years and are supported by "the state of the industry's" policies and technologies.

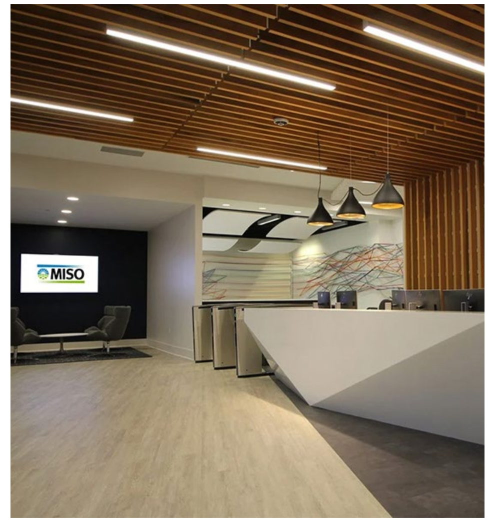
MISO currently has 36 issues in the parking lot, some of which are more than seven years old. Staff said some of the proposals have already been addressed with FERC rulemakings, as is the case with Order 2222 and allowing aggregators of distributed resources into the wholesale energy markets.

"We have every intention of being much more diligent on parking lot items" Lane promised earlier this year.

The parking lot designations were used under the RTO's *Integrated Roadmap* process, where stakeholder input was used to annually prioritize a list of market tasks and improvements. MISO ended the practice last year. (See *MISO Keeps Reduced Schedule for Rest of 2022*.)

The grid operator is also encouraging a more standardized method for stakeholders to submit new issues that they think deserve MISO's attention. After the roadmap process was scrapped, stakeholders said in public meetings they were left wondering how to broach ideas for improvements.

Staff stressed that stakeholders who want their ideas discussed in public meetings should complete its issues submission *form*. From there, the item is either directly considered by a stakeholder group or, when the assignment is less clear, the Steering Committee determines which stakeholder groups will take up the issues for consideration. ■



MISO's lobby at its Carmel, Ind., headquarters | *MISO*

MISO News

Court Blocks LS Power's Attempts for More Competitive MISO Tx Projects

By Amanda Durish Cook

The D.C. Circuit Court of Appeals last week twice rejected transmission developer LS Power's appeals to force MISO to open more projects to competition.

LS Power sought reversals of two FERC rulings, but in a pair of rulings issued Friday, the court declined to direct the commission to revisit its orders.

The developer challenged FERC's repeated refusal to compel MISO to lower its voltage threshold of competitive economic projects from 230 kV to 100 kV. It also unsuccessfully contested the RTO's practice of not cost sharing baseline reliability projects (BRPs) beyond the transmission pricing zone in which they're located.

The appeals court said the commission reasonably accepted 230 kV as the market efficiency project threshold (*20-1465*) and similarly acted sensibly when it kept BRPs' cost sharing to the transmission pricing zone in which they're physically located (*20-1421*).

LS Power argued before the court that its business will suffer if MISO is allowed to keep the voltage threshold and local cost sharing in place. The company said those criteria deny it the opportunity to participate in more competitive solicitations for transmission projects.

MISO in 2020 won FERC approval to overhaul its cost-allocation procedures. The grid operator lowered the voltage threshold for market efficiency projects that are regionally cost shared from 345 kV to 230 kV, added two new benefit metrics, and eliminated a 20% footprint-wide postage stamp allocation. (See *MISO Cost Allocation Plan Wins OK on 3rd Round*.)

The commission rejected LS Power's rehearing requests and complaint that a further reduction of the threshold to 100 kV was necessary. FERC found the 230 kV-threshold would spur more economic projects and expand the number eligible for competition. (See *La. and Miss. Join MISO, TOs in Opposing Cost Sharing at 100 kV*.)

FERC also refused LS Power's joint 2020 *complaint* with the Coalition of MISO Transmission Customers and the Industrial Energy Consumers of America. The parties alleged that MISO's nearly 10-year-old location-based cost-allocation methodology for BRPs didn't comport with the commission's principle that transmission projects' beneficiaries should pay for them.

In MISO, BRP costs are allocated only to local transmission pricing zones where project facilities are physically located; costs are recovered by the TOs developing the projects. They are not open to competitive bidding.

The court said LS Power's examples of BRPs with benefits spillover "was limited to a relatively small number" and "did not necessitate a categorical finding that location-based cost allocation is unjust and unreasonable." It said LS Power's "crown jewel of new evidence," was a report containing a line-outage analysis that showed only 12 of 29 MISO-approved baseline reliability projects during 2013-2018 could deliver more than "*de minimis*" benefits beyond their transmission pricing zone.

The court added that FERC "need not consider cost allocation rules on a project-by-project basis, which would unravel the framework of *ex ante* tariffs established by Order 1000."

In its voltage threshold ruling, the D.C. Circuit Court also rejected LS Power's request that MISO be prohibited from employing an "immediate need reliability exception," where the RTO can bypass a competitive solicitation process for certain urgently needed reliability projects. The court borrowed a line from FERC's Order 1000, noting that "if the time needed to solicit and conduct competitive bidding would delay the project and thereby threaten system reliability, then competitive bidding would not be required." ■

| LS Power

MISO News

SREA Criticizes Lack of MISO South Planning in FERC Tx Proceeding

By Amanda Durish Cook

The Southern Renewable Energy Association (SREA) said last week that while MISO may have a robust transmission planning process, FERC should know that the RTO's South region does not share in it.

The sentiment was made in comments to the commission under its transmission planning notice of proposed rulemaking. SREA accused Entergy, which comprises the majority of MISO South, of impeding and delaying transmission planning to benefit its bottom line. (See *Battle Lines Drawn on FERC Tx Planning NOPR*.)

"Overall, transmission planning in the south is lagging behind other regions," SREA said. "We are not prepared for the energy transition already underway, and some utilities in the region are actively opposing reasonable transmission planning practices. This places [President] Biden's Inflation Reduction Act at risk of not reaching its full potential."

The association said MISO South is a patchwork of load pockets that include Amite South, Downstream of Gypsy, West of the Atchafalaya Basin (WOTAB), Texas East and Texas West. SREA said Texas uses the load pockets to its advantage, constructing new generation in them and using the load pockets to justify "underinvesting in transmission to the benefit of its generators."

SREA said power outages were more prevalent in MISO South during the February 2021 winter storm. All eight of the transmission lines into New Orleans failed or collapsed during Hurricane Ida last year, leading to nearly a week of power outages. Estimates for Entergy grid repairs have topped $4.4 billion, about a third of all of MISO North's proactive long-range transmission plan (LRTP) projects, the group said.

SREA said that while Entergy's 2013 incorporation into MISO was meant to put an end to the utility's anticompetitive business practices, the RTO "has not been entirely effective at increasing competition." It said MISO South consultants bogged down planning that could have come from the grid operator's 2017 regional overlay study.

"When MISO South slows down transmission planning at MISO, the entire region is negatively affected. Opposition to MISO's transmission planning effectively delayed transmission by three years while MISO retooled to start the LRTP process," SREA said.

SREA pointed out that MISO was forced to bifurcate cost allocation between the Midwest and South in its LRTP so it could move forward on new transmission lines in the Midwest without risking delay from the more hesitant southern stakeholders.

MISO approved the first of four LRTP portfolios in late July. It contains 18 projects costing more than $10 billion, all destined for MISO Midwest. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

SREA also touched on the fact that the RTO has been unable to build any market efficiency projects in the South. Its lone competitive market efficiency build, the Hartburg-Sabine Junction project, is all but certain to be cancelled because Entergy added the 993-MW Montgomery County Power Station in southeast Texas and plans to construct the 1.2-GW natural gas and hydrogen-powered Orange County Advanced Power Station by 2026. The Hartburg-Sabine line was meant to alleviate the WOTAB load pocket. (See *MISO on Verge of Cancelling Hartburg-Sabine Tx Project*.)

The organization said there is a "demonstrated need to introduce transparency and competition in the region to mitigate the use of utility market power to thwart transmission solutions that would increase reliability and lower customer costs."

"I think the big idea here is MISO stakeholders went through a really long and arduous process to get where we are on LRTP," SREA Executive Director Simon Mahan said in an interview with *RTO Insider*.

Mahan said there's no need for MISO to "reinvent the wheel" on its transmission planning but emphasized that the grid operator's long-term planning needs to gain traction in MISO South.

Mahan said he felt a bit "jilted" that MISO Midwest is first in line for long-range transmission planning while MISO South utilities and regulators appear to favor a delay.

"I really hope that the regulators down here read our comments and really take them to heart," he said.

MISO so far envisions four LRTP portfolios. It doesn't plan on addressing MISO South needs until the LRTP's third iteration.

Mahan pushed back on the notion that the Midwestern portion of MISO needs more urgent transmission planning because it contains an aging coal fleet and a healthier appetite for renewable energy.

Damage to a Louisiana transmission tower from 2020's Hurricane Laura | *Entergy*

MISO News

"The reality is we have a lot of old gas generation in MISO South that operates similarly to aging coal plants," he said, noting the region is undergoing its own renewable energy transition.

For years, Mahan said he's wanted the two regions to share a better transmission connection so they can better share resources. Not addressing the Midwest-South constraint is to the detriment of MISO itself, he said.

"We can plainly see with Winter Storm Uri that getting that connection fixed is a matter of life and death," Mahan said.

He said building new import capability in MISO South for the sake of reliability is a must. While little load pockets in the wetlands, forests and swamps of Louisiana made sense decades ago, it isn't a reliable practice today, he said.

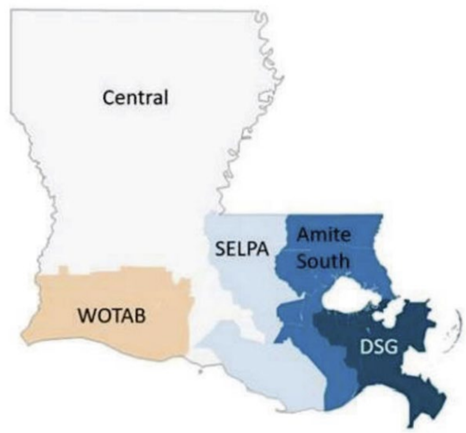
"We need to connect these regions because as hurricanes are pummeling our coast, it's becoming clear that generators can't take the direct hits," Mahan said.

Mahan said Entergy has a troubling pattern of supplanting transmission lines with new generation.

"This is a clear pattern that we've seen with Entergy proposing generation when lines are recommended. People need to know that this is going on so we can come up with solutions for it," he said. "We've seen it enough: Entergy plopping generation at the end of a new, large-scale transmission project, and the project dies. I'm very concerned that this strategy is working, but the generators rarely turn on."

Mahan said the St. Charles Power Station gas plant, built in place of a 2016 MISO-recommended 230-kV line spanning two substations in the New Orleans area, was derated to about half its capability during the winter storm. He also said Entergy's new Montgomery Power Station failed to come online during the same extreme weather event.

"Time and time again, Entergy keeps building power plants in these load pockets, and during these extreme events for whatever reason, they can't turn on. ... This isn't old generation. They're brand-spanking new power plants," Mahan said. "The reality is that the lights keep going out in MISO South, and transmission keeps not getting built. Those are pretty damning examples of what's going on in MISO South."



MISO South load pockets in Louisiana | *Entergy*

Mahan said he hopes that FERC's ultimate rulemaking will "codify the good work we've done here at MISO to ensure that no region is going to be left behind in the future."

Entergy had not returned a request for comment at press time about its philosophy on transmission planning. ■

NYISO News

NYISO 20-Year Forecast Highlights Generation, Tx Hurdles to Climate Goals

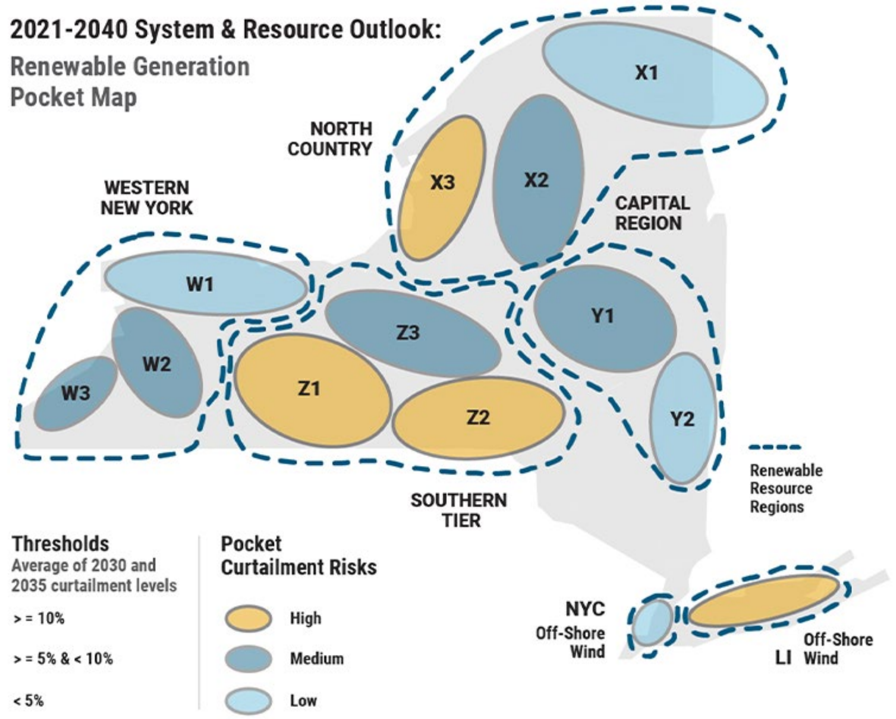
By John Norris and Rich Heidorn Jr.

NYISO's first 20-year economic planning forecast paints a daunting picture of the challenge facing New York in meeting its climate goals: More than 95 GW of new zero-emission resources must be added to the grid by 2040, 20 GW within the next seven years.

"That is significant," NYISO's Jason Frasier said in presenting the inaugural System & Resource Outlook to the Business Issues Committee on Wednesday. The 2030 goal represents half of the ISO's current 40-GW fleet.

Complicating matters, as fossil generation is eliminated, the state will need new clean energy generation technologies — potentially hydrogen, renewable natural gas and small modular nuclear reactors — which the report calls "dispatchable emission-free resources."

Also daunting: building the transmission needed to deliver that power. "The current New York transmission system, at both local and bulk levels, is inadequate to achieve currently required policy objectives," the ISO says in the report. "Some renewable generation pockets throughout the state already face curtailments. More curtailments will be experienced in the future [absent transmission upgrades] as an increasing number of intermittent generation resources interconnect."



Four "generation pockets" (tan ovals) present the state's biggest transmission needs. | *NYISO*

The Need for Change

The outlook, which will be performed every two years, replaces Phase 1 of the Congestion Assessment and Resource Integration Study (CARIS).

The new planning process was prompted by the 2020 Accelerated Renewable Energy Growth and Community Benefit Act, which mandated a statewide transmission planning study to achieve the targets of the 2019 Climate Leadership and Community Protection Act (CLCPA): 70% renewable energy by 2030 (70x30) and 100% zero-emissions by 2040.

The "plan further supports the state's mission by quantifying the evolving challenges in the electricity sector resulting from widespread beneficial electrification," the ISO said.

NYISO won FERC's approval for the new process last year, telling the commission in its transmittal letter that "no single NYISO planning study summarizes and evaluates the totality of New York state's transmission system needs" (ER21-1074).

The ISO said the shift from CARIS' 10-year horizon to a 20-year study period would "better capture trends in system congestion[,] the full benefits of potential transmission upgrades" and the long-term impacts of the CLCPA mandates. It also aligns with the 20-year study period that the ISO uses to evaluate proposed transmission solutions to address congestion in the Economic Transmission Project Evaluation (previously CARIS Phase 2).

The outlook assesses congestion statewide, in contrast with CARIS, which focused on only the top three congested transmission paths based on production costs — ignoring congested paths with lower production cost impacts but potentially higher benefit-to-cost ratios.

Under the previous process, NYISO also limited its transmission planning to the bulk power transmission facilities (BPTF) portion of the state's transmission system (generally 230 kV and higher), leaving its transmission owners to plan their local systems. Under the outlook, the ISO will identify congestion throughout the transmission system, although its evaluation of proposed transmission solutions will remain limited to the BPTFs, supplemented by transmission owners' local plans.

"Much of the transmission congestion identified in the 70x30 scenario resulted from local transmission constraints, which would likely not be identified in the top three most congested paths on the New York state transmission system," the ISO said.

The ISO said the new process will improve its analysis of the benefits of interregional transmission. "Based on past CARIS studies, interregional congestion has not risen to the top three most congested paths in order for it to be analyzed," it said.

Under the new process, the ISO will conduct its assessments of "generic" solutions (transmission, generation, demand response and energy efficiency) to the Requested Economic Planning Study (formerly the "Additional CARIS Study") and the Economic Transmission Project Evaluation.

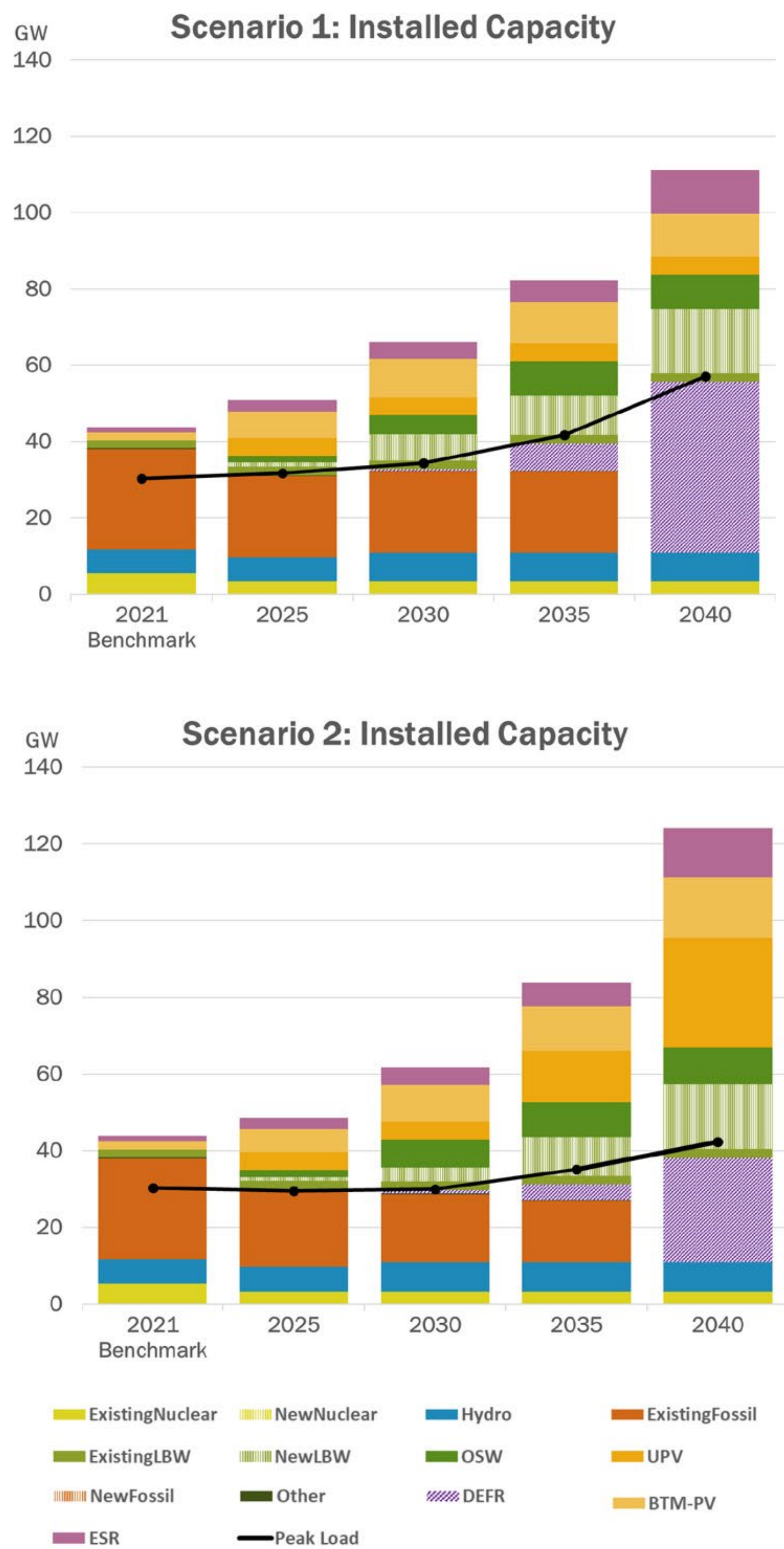
Unchanged is the ISO's process for evaluating proposed economic transmission projects or identifying load-serving entities that benefit from projects. The 80% voting threshold required for LSEs to approve such projects also is unchanged.

Four Futures

The outlook considered four potential futures:

NYISO News

- The Baseline Case assumed little change from the status quo.
- The Contract Case includes nearly 9,500 MW of renewable capacity procured by the state (4,262 MW of solar, 899 MW of land-based wind and 4,316 MW of offshore wind).
- The Policy Case looks at two futures selected from dozens of preliminary scenarios that varied based on factors such as capital costs and demand forecasts. "Among all factors tested, the demand forecast demonstrated the largest impact on the resulting capacity expansion," the ISO said.
- Scenario 1 envisions high demand (57,144 MW winter peak and 208,679 GWh energy demand in 2040) with fewer restrictions on renewable generation buildout options and land-based wind largely used to meet emission targets.
- Scenario 2 used assumptions consistent with the New York Climate Action Council's *Integration Analysis* and sees a moderate peak but a higher overall energy demand (42,301 MW winter peak and 235,731 GWh energy demand in 2040) with a mix of land-based wind and solar.



NYISO's two "Policy Case" scenarios use land-based wind (LBW), offshore wind (OSW), utility-scale solar (UPV), behind-the-meter solar (BTM-PV) and energy storage (ESR) to meet the state's climate policy mandates through 2035.| *NYISO*

DEFRs

The 20 GW of new generation needed in the next seven years dwarfs the 12.9 GW of generation developed since wholesale electricity markets began more than 20 years ago, the report notes. Over the past five years, 2.6 GW of renewable and fossil-fueled generation came into service — while 4.8 GW was deactivated.

The 9,500 MW of new contracted renewable resources projected would be a five-fold increase in the ISO's current utility-scale renewable fleet. "Without any major transmission upgrades planned to specifically address this large influx of contracted renewables, transmission congestion increases. When the contracted renewable projects are added, several additional constraints appear, causing a 23% increase in congestion statewide by 2030."

Most of the renewable projects are expected to be upstate solar or downstate offshore wind projects scheduled for installation before 2026. (In 2021, zero-emission resources made up 91% of upstate production, while fossil units dominated downstate (89%).)

The future will also mean an increase in dispatchable generator starts and stops and daily ramping to address the variability of wind and

NYISO News

solar generation. While flexible units will be dispatched more frequently, they will operate for fewer hours within the year.

To achieve the CLCPA target, all fossil generation is assumed to be retired by 2040, replaced by "dispatchable emission-free resources" (DEFRs), "a proxy technology that will meet the flexibility and emissions-free energy needs of the future system but are not yet mature technologies that are commercially available."

Scenario 1 assumes 45 GW of DEFR capacity by 2040 because of a 35% higher peak load forecast than Scenario 2, despite a 13% lower annual energy demand. The report notes that New York's current fossil fleet is only 26 GW. Scenario 2 envisions 27 GW of DEFRs by 2040.

A scenario in which DEFRs are not available because of a lack of investments in research, development and commercialization "exhausts the amount of land-based wind built and results in the replacement of 45 GW of DEFR capacity in Scenario 1 with 30 GW of offshore wind and 40 GW of energy storage," the outlook says.

That would also necessitate system reinforcements to address voltage support and dynamic stability problems that would arise without the fossil fleet or DEFRs.

Transmission Curtailments

New York is expected to see a major reduction in congestion on its Central East interface once the AC Transmission Public Policy projects in the Mohawk and Hudson Valleys are completed in 2024 and more than 10 GW of nuclear plant capacity in Ontario is retired or shut down for refurbishments by 2025. Nearly all of the economic energy exports to NYISO from the Ontario Independent Electric System Operator are delivered via the Central East interface.

But the reduced congestion will be short-lived as new renewables are connected upstream of the Central East interface, the outlook says.

A lack of sufficient transmission would result in increasing curtailments of both renewable and dispatchable generation, with renewable generators averaging 5 GWh per year in the Baseline Case, rising to 163 GWh in the Contract Case. Most of the curtailments affect offshore wind projects connected to Long Island, the report says.

The report predicts curtailment of at least 5 TWh of renewable energy in 2030 and 10 TWh in 2035 because of transmission limitations in renewable pockets. "This equates to roughly 5% less renewable energy that can be produced, and thus may not be counted toward the CLCPA targets."

Generation Pockets

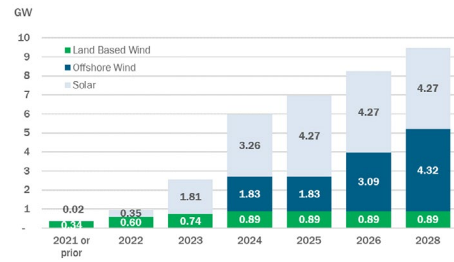
The report identifies four "generation pockets" that will need transmission expansions to avoid "persistent and significant limitations" to deliverability:

- Long Island offshore wind: NYISO is currently evaluating proposals submitted in response to the Long Island Offshore Wind Export *Public Policy Transmission Need*, which could reduce projected congestion "significantly," according to the report. The solicitation seeks to deliver at least 3,000 MW of offshore wind by increasing the export capability of the LIPA-Con Edison interface connecting Zone K to Zones I and J and upgrading associated local transmission. "However, offshore wind resource additions of up to 20 GW that are under discussion may necessitate additional transmission to deliver offshore wind energy to New Yorkers," the outlook says.
- The Watertown/Tug Hill Plateau renewable generation pocket (designated as X3 on the ISO's map): The 115-kV network can't deliver all of the already-contracted wind and solar generation in the area, and congestion will worsen with integration of more renewables.
- Southern Tier (Z1) and Finger Lakes (Z2) renewable generation pockets: The areas are attractive to wind and solar developers. "Transmission expansion from this pocket to the bulk grid would benefit New York consumers statewide," the report says.

Comments

The outlook was generally well received by BIC members, who voted to recommend it to the Management Committee. That committee is scheduled to vote on it on Aug. 31, which will be followed by a vote by the ISO's Board of Directors in late September. The ISO will then hold a public information session on the report.

Chris Hall, of the New York State Energy Research and Development Authority (NYSERDA), praised the report, although he said the authority "didn't necessarily agree with every single modeling assumption" and will propose changes in the future. NYSERDA would have liked more time for the study, he said, "but we recognize pencils have to be put



Cumulative contracted renewable capacity additions by online year | *NYISO*

down at some point."

Mark Younger of Hudson Energy Economics noted that while the outlook considered major changes in New York, it did not address the scale of changes occurring in neighboring regions. He argued that NYISO should not draw any conclusions about how it should address its interface with its neighbors without more analysis on the degree to which they can provide each other excess energy when it is needed.

Attorney Doreen Saia, of Greenberg Traurig, said she was concerned that the outlook's executive summary focuses on changes needed as the state approaches 2040.

"There's a very significant need now and in the near term. And I don't want that to get muted," she said. "We have to presume that there will be some subset of folks who only read the executive summary."

Zach Smith, NYISO vice president of system and resource planning, said the ISO's communications about the report will note the timing considerations at issue.

Next Steps

NYISO said data from the outlook will be used in the 2022 Reliability Needs Assessment (RNA) to identify commitment and dispatch trends and reliability impacts, as well as in the 2022 Grid in Transition study.

The ISO will open a 60-day comment period at the end of August or early September for its 2022-2023 Public Policy Transmission Planning cycle.

"The challenges identified in the outlook cannot be solved by any single entity," the report says. "The full set of comprehensive electric system requirements will need participation among policymakers, generator owners, transmission owners and consumers. Communication and collaboration between stakeholders is essential to making progress toward achieving policy objectives while maintaining an efficient power market and reliable power grid." ■

NYISO News

NYISO: $1.5B in Tx Upgrades Needed to Deliver 2021 Class Year

Wind Tops Solar in NYISO 2021 Generation Projects

By Rich Heidorn Jr.

About 40% of the proposed capacity seeking interconnection in NYISO's class year 2021 is not deliverable without expensive transmission upgrades, the ISO told the Operating Committee Aug. 18.

To obtain capacity resource interconnection service (CRIS) — required for projects to participate in the NYISO's wholesale capacity market — projects must be found "deliverable" at their requested CRIS level. If a project fails the applicable deliverability tests, system deliverability upgrades (SDUs) are required to obtain CRIS. Projects can proceed without committing to accept SDUs if they are willing to participate only in the ISO's energy market.

The ISO's Facility Studies Preliminary Deliverability Analysis Draft Report, which was approved by the committee Thursday, estimated that if all projects in the 2021 Class Year accept their cost allocations in the initial decision round, almost $1.5 billion in upgrades would be required for the 16 projects found not deliverable, 10 of them on Long Island.

If all 10 of the projects on Long Island proceed, the SDUs would cost an estimated $914 million (±50%) in upgrades, including two phase angle regulator (PAR)-controlled 138-kV lines, uprating of six 69-kV lines, and addition of a third circuit between the EGC tap and Valley Stream 138-kV line.

Five solar projects in the Thousand Island area near the St. Lawrence River that failed the deliverability test would require an estimated $200 million (±50%) to rebuild 25 miles of the Taylorville-Boonville lines 5 and 6 if all five projects proceed with their requested CRIS.

The 650-MW Swiftsure Energy Storage project in New York City would need to commit to funding an SDU, including a PAR-controlled 345-kV line between the Goethals 345-kV station and the W. 49th Street 345-kV station, at an estimated $382 million (±50%), to obtain CRIS.

Developers whose projects failed the deliverability tests have been given 10 days to decide whether to proceed to additional SDU studies, which would provide binding cost estimates.

The 2021 class year included 55 projects totaling 10,148 MW that requested CRIS, including seven wind projects totaling 3,076 MW; 22 solar projects (2,650 MW); 23 energy storage projects (2,902 MW); and one 270-MW solar/storage hybrid project. Also in the class were two projects related to the Champlain Hudson Power Express's plans to inject 1,250 MW at the New York Power Authority's Astoria Annex 345-kV substation.

New York City (Zone J, 13 projects, 2,818 MW), Long Island (Zone K, 10 projects, 2,867 MW) and the Central area (Zone C, seven projects, 785 MW) had the majority of the projects.

Interconnection Study Process Questioned

The ISO's review of the reliability impact study for an 80-MW solar project seeking to connect to a 115-kV line on National Grid's Niagara Mohawk Power (NYSE:NGG) system prompted questions about the grid operator's study processes from Operating Committee Chair Matt Antonio, an operations manager at National Grid's control center.

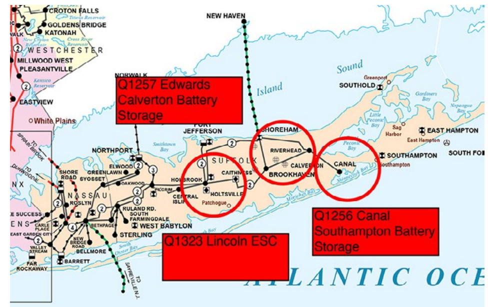
The Tabletop Solar Project (queue #869) would connect on the Clinton Substation-Clinton Tap 115-kV line in Montgomery County, N.Y.

The ISO found the project caused N-1-1 thermal overloads and N-1-1 over- and under-voltages in the study area. The thermal overloads were fully mitigated by re-dispatching the generation at the Moses-Saunders dam on the St. Lawrence River. The high-voltage violations observed were mitigated or brought to pre-project voltages by turning on a reactor at Coopers Corner. The low-voltage conditions observed were mitigated by changing the tap positions of Rotterdam transformers 7 and 8 and the Inghams PAR after the first level contingency.

"I don't believe that [the report] reflects reality, and how the system would actually be operated," said Antonio. Re-dispatching Moses-Saunders "may be an answer, but it isn't necessarily the answer that would be taken in real-time."

Antonio also questioned the report's finding of an instability problem, which the ISO ultimately determined was present in the pre-project base case. He said such reports should be subject to a "sanity check" before they are released to ISO members for approval. "The report was put out saying there's a stability issue pre-project. So that's worrisome," he said.

The ISO said the issue appears to be a modeling discrepancy in the pre-project case



Ten generation and storage projects proposed on Long Island may need an estimated $914 million (±50%) in transmission upgrades to participate in the capacity market in NYISO. | *NYISO*

and agreed to investigate the modeling issue further.

The ISO's Thinh Nguyen said the grid operator didn't find it necessary to hold off on Operating Committee approval of the study report, saying there was no need "to hold the project hostage" when the problem is with the base case and not because of the project itself. He said finding the cause of the modeling discrepancy is "like finding a needle in a haystack," but committed to investigate it further to avoid confusion in future studies.

Antonio said he would like to see the ISO's process "more streamlined … more thorough and more accurate."

Nguyen closed the meeting by announcing that ISO officials will present plans for improving the interconnection process at the next Transmission Planning Advisory Subcommittee meeting Sept. 1.

He said the ISO improved its portal to increase the transparency to project stakeholders in April and is seeking to hire two project managers to provide "one-on-one service" to project developers. In addition, the ISO is seeking to add two stakeholder services representatives to help manage stakeholder inquiries related to the interconnection process.

Antonio asked if the ISO was attempting to shorten the process, saying National Grid must refer potential customers to the ISO for connecting loads larger than 10 MW. "It's tough to explain to a customer, and occasionally they make the decision that New York isn't the place for them because of how long it takes," he said.

Nguyen responded that the ISO plans to "streamline the scope without jeopardizing the reliability of the system." ■

PJM News

FERC Rejects PJM's Reserve Deployment Proposal

By Michael Brooks

FERC on Aug. 15 rejected PJM's proposal to change how it handles synchronized reserve events, saying it would likely result in higher prices and lead the RTO to procuring more energy than the system actually needs during emergencies (*ER22-1200*).

Called Intelligent Reserve Deployment (IRD), PJM's proposed construct would have it use a real-time security-constrained economic dispatch (RT SCED) case that simulates the loss of the largest generation unit on its grid during a synchronized reserve event. Such events can be caused by the loss of generation, loss of transmission or sudden increase in load.

Currently, PJM responds to these emergencies by issuing an "all-call" message to all market participants to deploy their available resources. The RTO argued that IRD would be more efficient and that, by using RT SCED, it would better align prices with actual grid conditions and trigger resource-specific responses.

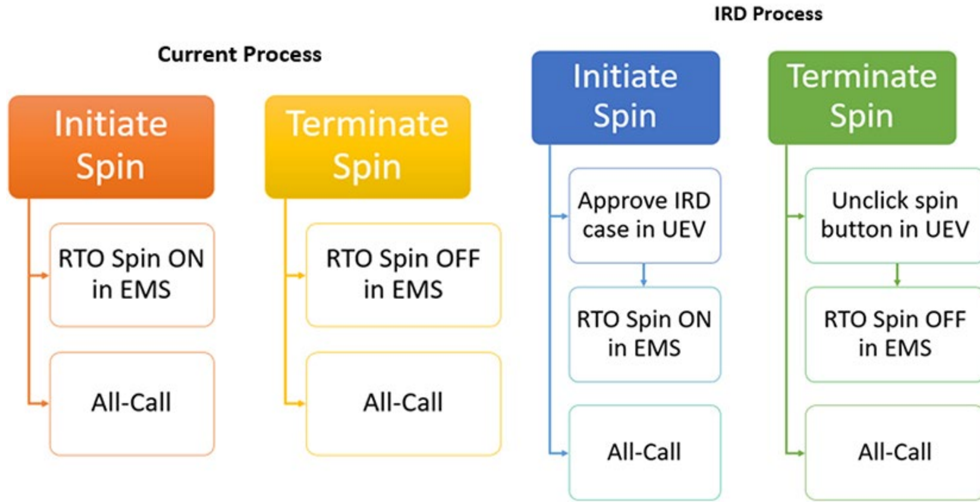
But FERC was unpersuaded, ruling 4-1 that IRD "fails to model actual system conditions.

"It therefore is likely to result in artificially inflated prices and thus prevent PJM from achieving a least-cost dispatch solution to address synchronized reserve events, which could in turn produce a misalignment between prices and actual system conditions."

IRD would simulate the loss of the generator by effectively increasing the load forecast by the equivalent capacity. Thus, FERC found, it would not lead to accurate dispatch, as most reserve events are likely to be smaller in nature.

"IRD would result in PJM setting prices as though the largest contingency had occurred, and then immediately procure additional reserves accordingly, without regard for the size and location of the actual system event," the commission said. Even if the emergency were the result of the largest contingency, "the IRD SCED case might not be representative of actual system conditions if the contingency event occurs near a constraint or within a reserve sub-zone ... because IRD would model an RTO-level increase in load," FERC said.

PJM filed its proposal in March under Section 205 of the Federal Power Act, after it received final stakeholder approval in January, though with 18 objections. (See "Consent Agenda," *PJM MRC/MC Briefs: Jan. 26, 2022*.) FERC acknowledged that the current all-call approach could be improved upon, but the RTO "must show that any such proposed methodology produces just and reasonable rates."



PJM's proposed Intelligent Reserve Deployment construct | *PJM*

FERC agreed with arguments by the RTO's Independent Market Monitor and the PJM Industrial Customer Coalition that the proposal would result in unjustly higher prices. But it also noted that, in response to their protests, PJM had acknowledged that the price resulting from IRD cases "is not perfect," though it emphasized that it would be more accurate than under the all-call approach.

"Even if that characterization were true, that does not render this particular proposal to use the largest contingency in the IRD case just and reasonable," the commission said.

Danly Dissent

Commissioner James Danly dissented, arguing that PJM "easily met its Section 205 burden" and rejecting the majority's conclusion that IRD would "artificially inflate prices."

"I see nothing wrong with modeling the single largest reliability contingency during a reserve shortage, for example, when the system is dangerously exposed to a subsequent reliability event," Danly said.

Danly argued that IRD would clearly be an improvement over the all-call approach, which he said "is essentially an email blast" that "apparently is routinely ignored by resources not subject to nonperformance penalties. It does not take an engineer to identify a legitimate reliability risk here."

"I would not reject a clear reliability enhancement merely because it results in potentially higher (albeit more efficient) prices," he said. "FPA Section 205 contemplates broad discretion for utilities to grapple with challenges and opportunities as they see fit. This filing easily fits within the range of acceptable filings."

He concluded that, despite rejecting the proposal, "we at the commission will enthusiastically join the throngs blaming PJM if, down the road, it suffers a blackout caused by back-to-back reliability events."

The majority responded to Danly's dissent by noting that PJM acknowledged that the system would remain reliable without IRD. It also argued that part of Danly's argument was apparently based on the fact that Tier 1 synchronized reserve resources are not subject to nonperformance penalties, but it noted that the commission had already approved PJM consolidating Tier 1 and 2 resources into a single product, which will be subject to penalties and go into effect Oct. 1. (See *FERC Approves PJM Reserve Market Overhaul*.) ■

PJM News

PJM MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the PJM Markets and Reliability and Members committees on Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

RTO Insider will be covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Members will be asked to endorse revisions to Manual 6: Financial Transmission Rights as part of a periodic review and changes to conform with tariff revisions intended to increase transparency into and the efficiency of the RTO's auction revenue rights and financial transmission rights markets. The changes were approved by FERC in March (*ER22-797*). (See *FERC Accepts PJM ARR/FTR Market Changes*.)

Endorsements (9:10-10:15)

1. Variable Environmental Costs and Credits (9:10-9:35)

The MRC will be asked to approve a proposed update to rules governing variable environmental charges and credits and their inclusion in cost-based energy offers. Generation units receiving production tax credits or renewable energy credits must reflect them in their fuel-cost policies when submitting non-zero cost-based offers into the energy market. The changes will include revisions to Manual 15: Cost Development Guidelines and Operating Agreement Schedule 2. (See "Variable Environmental Costs and Credits," *PJM MIC Briefs: May 11, 2022*.)

Issue Tracking: *Variable Environmental Costs and Credits*

2. 2022 Quadrennial Review (9:35-10:15)

The MRC will cast advisory votes on four alternative sets of capacity auction parameters as part of its 2022 Quadrennial Review. Members will be asked to select one of the packages from PJM, the Independent Market Monitor, Calpine and Cogentrix for a recommendation to the Board of Managers consideration. (See "2022 Quadrennial Review," *PJM MRC/MC Briefs: July 27, 2022*.)

Issue Tracking: *2022 Quadrennial Review*

Special Members Committee — Quadrennial Review

Endorsements (1:25-2:15)

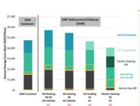
1. 2022 Quadrennial Review (1:25-2:15)

The MC also will take advisory votes on the proposed Quadrennial Review packages. (See MRC item 2.) ■

— Rich Heidorn Jr.

Mid-Atlantic news from our other channels

NJ to Invest $10.8M in EV Chargers, School Buses — NetZero Insider



NJ BPU Approves Report on Costs of Energy Master Plan — NetZero Insider

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

PJM News

FERC OKs GreenHat Settlements

Principals to Pay PJM $1.4M, a Fraction of RTO Members' $180M Loss

By Rich Heidorn Jr.

The principals of GreenHat Energy will pay PJM almost $1.4 million to settle claims over the company's spectacular default in the RTO's financial transmission rights market, which cost members almost $180 million.

GreenHat founders *John Bartholomew and Kevin Ziegenhorn* will pay $375,000 and $400,000, respectively in disgorgement, with the *estate* of founder Andrew Kittell paying $600,000 under settlements approved by FERC in two orders Aug. 19 (IN18-9). Kittell died in January 2021.

Bartholomew and Ziegenhorn also agreed not to participate in FERC-jurisdictional markets for 10 years. "In the case of PJM markets, the agreed prohibition is permanent," FERC said.

The GreenHat principals also consented to the entry of a judgment of $179.6 million against the company in a lawsuit pending in state court in Texas, but with the company insolvent, the judgment is moot.

"GreenHat and the [Kittell] estate state they are unable to pay the assessed amounts and have furnished confidential financial disclosures sufficient to substantiate their claim," FERC said. "The agreed settlement amount is based on ability to pay in light of financial information provided by the estate and GreenHat to [FERC's Office of] Enforcement."

The disgorgements by Bartholomew and Ziegenhorn also were based on their ability to pay, FERC said.

The three founded GreenHat in 2014 to trade FTRs in PJM, eventually acquiring a portfolio of 889 million MWh. When the company defaulted in June 2018, however, the company had less than $560,000 in collateral with PJM. (See *Doubling Down — with Other People's Money*.)

"Over the next three years, GreenHat's default required PJM to assess other members of PJM a total of $179,600,573," FERC said.

Following an investigation, FERC assessed civil penalties of $179 million on the company and $25 million against the three principals, accusing them of violating the commission's Anti-Manipulation Rule by purchasing FTRs with virtually no upfront cash, planning not to pay for losses at settlement and selling profitable FTRs to third parties. The commission said they also purchased FTRs based not on market considerations but to amass as many FTRs as possible with minimal collateral; they also made false statements to PJM about money purportedly owed by Shell Energy North America to convince PJM not to proceed with a planned margin call. FERC said they also submitted inflated bids into an FTR auction in an attempt to inflate the clearing price of FTRs that Shell had purchased from GreenHat. (See *FERC Levies $242M in Fines on GreenHat, Owners*.)

Under the settlement, the principals did not admit or deny the alleged violations. GreenHat agreed to dismiss its lawsuit seeking more than $62 million from Shell in addition to the $13.1 million that Shell paid GreenHat in 2016 and 2017.

PJM and Shell also agreed to settle their billing dispute over Shell's obligations to indemnify PJM over its FTR trades with GreenHat. PJM also agreed to drop a lawsuit it filed in California against the Kittell estate.

"This settles all pending litigation," PJM spokesman Jeff Shields said Monday. "We appreciate FERC's leadership on resolving these matters." ■

GreenHat listed its address as 826 Orange Ave., Suite 565, Coronado, Calif. — a UPS store between a nail salon and a RiteAid. | *Google*

SPP News

FERC Approves SPP Request for Uncertainty Product

By Tom Kleckner

FERC last week accepted SPP's proposed tariff revisions to add an uncertainty reserve product to its Integrated Marketplace (*ER22-914*).

SPP said the product will address the need for flexible capacity when realized generation, load and net scheduled interchange deviate from its forecasts. The rising penetration of renewable resources in the RTO's resource mix has increased the variability that it must manage in its market and reliability operations, it argued.

The RTO will procure uncertainty reserves by reserving a portion of a dispatchable resource's upward ramping capability to address increasing net obligations in future dispatch intervals.

Resources that can follow real-time dispatch instruction and increase and maintain its output, once the specified output is met, for at least one hour can provide the product. That applies to both online and offline resources.

The grid operator's resources will make themselves available through self-certification but can opt out with qualification and dispatch status. SPP will derive the value of resources clearing online uncertainty reserve using a loss-of-opportunity metric, similar to how it treats its existing ramp capability-up product. Offline resources offering uncertainty reserves will have an offer cap of $1,000/MW and a $0/MW floor; a demand curve will price the product when its availability on the system is scarce.

The RTO will impose a nonperformance penalty on resources when cleared real-time uncertainty reserves does not operate in a responsive manner.

SPP's Market Monitoring Unit intervened in support of the RTO, saying the changes would significant improvements over manual commitments and will provide a market solution for midterm ramp capacity. That will result in increased flexibility to meet ramping needs, increased price accuracy for online resources and increased price transparency of ramping capacity's value, the MMU said.

In its Aug. 16 order approving the proposal, FERC agreed with SPP's request for a placeholder effective date so that it can develop the necessary software changes to implement the revisions. The grid operator expects the changes to be ready later this year and committed to specify the effective date at least 30 days in advance.

The tariff revisions were filed with FERC after the SPP Board of Directors and stakeholders approved the proposal in July 2021 after several years of development. The uncertainty reserve product was one of 21 recommendations made in 2019 by the Holistic Integrated Tariff Team. (See "Uncertainty Product Endorsed," *SPP Markets and Operations Policy Committee Briefs: July 12-13, 2021*.) ■

The growing penetration in SPP's fuel mix of renewable resources, like Duke Energy's Frontier Windpower II facility in Oklahoma, led it to design an uncertainty reserve product. | *Duke Energy Renewables*

Company Briefs

Fisker Considers US Ocean Production Amid EV Tax Credit Shakeup

Fisker, a Los Angeles-based electric vehicle startup planning to deliver European-built SUVs later this year, is looking into adding a U.S. production site for its Ocean model. Changes to federal EV tax credits given to car buyers now favor vehicles assembled at domestic plants.

Fisker's Ocean SUV is expected to go into production in November at a plant in Graz, Austria, but with reservations exceeding 58,000 units before deliveries have begun, Fisker said it may also need a U.S. production site to meet future demand. The Ocean will have a base price of about $37,500, with top-end versions going for more than $70,000.

The company insisted that the loss of customer tax credits under the Inflation Reduction Act signed is not a trigger for the move.

More: *Forbes*

Rivian Cancels Explore EV Truck

Rivian last week announced that it is eliminating the production of the Explore model of its electric truck line, which the company said will help it streamline its supply chain and deliver vehicles more quickly.

The Explore model retailed at $67,500 and demand was smaller than anticipated. The "vast majority" of customers have ordered the next trim level, the $73,000 Adventure configuration, Rivian said. Explore purchasers will have until Sept. 1 to upgrade or cancel their order.

More: *Bloomberg*

Hyundai May Speed up Construction of US EV Plant

A new U.S. law excluding electric vehicles assembled outside of North America from tax credits could persuade Hyundai Motor to expedite the start-date for construction of its EV and battery plant in the country to as early as this year, according to the Yonhap news agency.

Hyundai said in May that it would break ground on its new Georgia facility in early 2023, with commercial production starting in the first half of 2025. But the company is now considering starting construction later this year to begin commercial production in the second half of 2024.

More: *Reuters*

Federal Briefs

Study: New Climate Law to Cut Carbon Pollution 40%

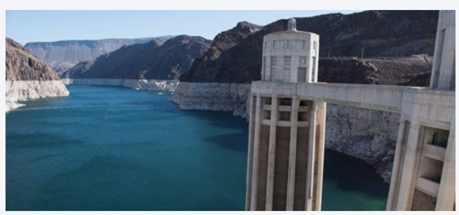
Clean energy incentives in the new spending package signed last week by President Joe Biden will trim America's emissions of greenhouse gases by about 1.1 billion tons by 2030, according to a Department of Energy analysis.

The analysis finds that between the Inflation Reduction Act and last year's infrastructure spending law, U.S. greenhouse gas emissions should be about 40% lower than 2005 levels by 2030. The first official federal calculations say the nation will produce 1.26 billion fewer tons of carbon pollution — saving the equivalent of the annual greenhouse gas emissions of every home in the country.

Most of the projected emissions reductions would come in promoting clean energy.

More: *The Associated Press*

WAPA Hydropower to Serve More Customers



Eleven municipalities in Kansas and Nebraska and one military installation in Colorado have been approved to receive at-cost federal hydropower from the Western Area Power Administration's Loveland Area Projects beginning Oct. 1, 2024.

In total, the new customers will receive 11,302,438 kWh in the summer season and 9,106,151 kWh in the winter season. To begin receiving the hydropower, the customers must sign a power contract by Dec. 31 and have transmission arrangements in place by summer 2024

It is the largest addition of WAPA customers since the remarketing of Hoover Dam hydropower in 2017.

More: *WAPA*

TVA, Ontario Power to Develop Small Modular Reactors

The Tennessee Valley Authority last week announced it will work with the Ontario Power Group (OPG) to develop and build several small modular reactors designed by General Electric and Hitachi.

OPG is completing a $13 billion refurbishment of its four reactors at Darlington in Ontario and is planning to build small modular reactors at the site using the GE Hitachi BWRX design. TVA, which is pursuing the same technology for its next generation of smaller nuclear plants, reached an agreement with OPG to share information regarding the development, licensing and construction of the 300-MW, light-water modular reactors.

TVA currently holds the only early site permit in the U.S. from the Nuclear Regulatory Commission to locate a small modular reactor at the Clinch River Nuclear site.

More: *Chattanooga Times Free Press*

State Briefs

ARIZONA

Tucson Electric Power's Energy Efficiency Programs Get $12M Boost

The Corporation Commission last week voted 3-2 to order Tucson Electric Power to redouble its efforts to spend more than $12 million on energy-efficiency rebates and related programs.

TEP had sought to refund about $12.4 million collected through its "demand-side management" surcharge for the past two years but didn't spend, as COVID-19 restrictions limited customers' energy-efficiency projects and some programs reached their budget caps. However, the commission ordered TEP to come up with a plan to spend the money on energy-efficiency programs.

More: *Tucson.com*

CALIFORNIA

PacifiCorp Sued, Accused of Causing McKinney Fire

A lawsuit filed last week against PacifiCorp alleges the utility's equipment caused the McKinney Fire, which has destroyed 185 structures and killed four people in Siskiyou County.

The McKinney Fire started July 29 near a place where PacifiCorp has a transmission line, the suit says. One of the attorneys handling the case said his firm cannot say definitively the utility started the fire but that the evidence points to the company's equipment as the culprit.

Kaitlyn Webb, a spokeswoman for the U.S. Forestry Service, said the cause of the fire is still under investigation.

More: *Redding Record Searchlight*

COLORADO

Delta County Reverses Course on Solar Project

Delta County commissioners last week unanimously approved the 80-MW Garnet Mesa solar project.

The project had been rejected by the commission in March because of concerns about the loss of farmland and opposition from neighbors. Developer Guzman Energy revamped its plan by adding irrigation to support more sheep than initially proposed — as many as 1,000 — and the prospect of using the land for an apiary.

The project had met all the requirements of the county's land use code and met requirements the federal Bureau of Land Management uses for siting solar projects. It is also posting a $4.5 million bond to ensure the cleanup of the land.

More: *The Colorado Sun*

FLORIDA

Duke Energy Ordered to Refund $16M Following St. Pete Power Plant Issues

The Public Service Commission last week upheld an administrative law judge's recommendation that Duke Energy refund $16.1 million to customers in a case that stemmed from problems at the utility's Bartow power plant.

The case involves allegations that Duke's predecessor, Progress Energy Florida, operated a turbine at the plant beyond its capacity, which lead to problems that forced a 2017 outage.

The judge recommended Duke return $11.1 million in "replacement power" costs, as well as $5 million to cover costs of replacement power needed because the turbine operated below expected levels from 2017 to 2019 after coming back online.

More: *News Service of Florida*

IDAHO

Minidoka Commissioners Oppose Lava Ridge Wind Project

The Minidoka County Commission last week passed a resolution in opposition to the proposed Lava Ridge Wind Project because of concerns that a large-scale project on public lands would have a negative impact on the rural county.

LS Power, the developer of the project, has requested a permit from the Bureau of Land Management to place about 400 wind turbines on public lands in Lincoln, Jerome and Minidoka County. The commission has asked the BLM to conduct an analysis of the effects the project would have on the quality of life in the county.

If approved, the project would double the amount of wind energy produced in Idaho.

More: *MagicValley.com*

ILLINOIS

ComEd to Pay $38M in Rebates in Wake of Bribery Scheme

The Commerce Commission last week approved a plan for ComEd to issue a $38 million rebate to customers in the wake of a bribery scheme.

A $31 million rebate will be issued by the company directly to consumers to help pay off costs associated with the bribery scheme, while another $7 million rebate will be awarded to consumers through a "federal regulatory process," the ICC said. ComEd also was required to pay a $200 million fine as part of a deferred prosecution agreement.

While it is unclear when the rebates will be issued, the amount would average around $5 per customer.

More: *WMAQ*

LOUISIANA

Cleco to Revive Former Coal Plant as Solar Facility

Cleco Power last week announced it is teaming up with D.E. Shaw Renewable Investments to transform the former Dolet Hills coal plant into a $250 million solar farm.

The utility and Southwestern Electric Power Company shuttered the 650-MW coal plant in 2021 after the plant was no longer competitive. The solar farm, which would generate 240 MW, will begin generating power by 2025 if it is approved by the Public Service Commission.

Cleco generated about 55% of its power in 2021 from natural gas and less than 2% from renewable sources.

More: *The Acadiana Advocate*

NEBRASKA

OPPD Extends Coal Plant Closure Date

The Omaha Public Power District Board of Directors last week unanimously voted to extend operations at the 645-MW North Omaha coal plant until 2026. It became at least the sixth U.S. coal plant to delay its closing this year, citing concerns about energy shortages.

The board said its decision was due largely to delays in hooking up two new natural gas plants to the grid. The company also cited slowdowns in implementing large-scale solar arrays, due to "project siting issues and supply chain challenges, including impacts from the federal focus on solar panel imports."

More: *Reuters*

NEW JERSEY

BPU Welcomes New Commissioner

The Board of Public Utilities last week welcomed Dr. Zenon Christodoulou as the board's newest commissioner.

Christodoulou has had a distinguished career in business and academia. He has been a management consultant in various industries and has owned businesses in print manufacturing, graphic design, the restaurant industry, and the media sector. Additionally, he teaches as an adjunct professor at William Paterson University.

More: *New Jersey BPU*

NEW MEXICO

Investigation Says Ruidoso Fire Was Caused by Power Lines

Wildland Fire Investigator Scott Chalmers of the Energy, Minerals and Natural Resources Department last week issued a report claiming the McBride Fire was started by a tree falling on Public Service Company of New Mexico power lines.

Strong winds toppled a drought-stressed tree on April 12, causing electrical lines to arc and ignite the fire, the report said. The fire killed an elderly couple and destroyed more than 200 homes in the Ruidoso area.

The fire has spawned two lawsuits alleging that PNM and a contractor caused the fire by failing to properly maintain trees and vegetation near its power lines. PNM claims the tree was located outside of its right of way and has denied any fault or wrongdoing.

More: *Albuquerque Journal*

PNM Ordered to Show it is Following Through with Rate Credits

The Public Regulation Commission last week unanimously approved an order asking the Public Service Company of New Mexico to prove that it is following a previous order to issue rate credits so that customers are not paying for a coal plant that is being retired.

The average residential customer should see a $1.76 rate credit to reflect that unit one of the San Juan Generating Station is no longer in use. Starting in October, the credit will increase to $8.19 after the last operating unit is retired.

PNM has appealed the commission's order requiring rate credits to the state Supreme Court and has until Aug. 24 to file a compliance report with the PRC.

More: *NM Political Report*

NORTH DAKOTA

No Bids Submitted for Natural Gas Pipeline

North Dakota received no bids by the Aug. 15 deadline for a pipeline that would carry natural gas across the state and supply energy to proposed agricultural manufacturing processing plants in Grand Forks.

It is the second time there were no bids for the project, as there were no bids on the project by the initial May 1, deadline.

Pipeline Authority Director Justin Kringstad will further discuss the project with Industrial Commission members Gov. Doug Burgum, Attorney General Drew Wrigley and Agriculture Commissioner Doug Goehring at an Aug. 26 meeting.

More: *AG Week*

OHIO

DOJ Asks PUC to Back off FirstEnergy Bribe Investigation

Kenneth L. Parker, the U.S. Attorney for the Southern District of Ohio, sent a letter to the Public Utilities Commission last week asking it to stay its four investigations into FirstEnergy's conduct, which overlap in part with the prosecution. He asked for a freeze of at least six months.

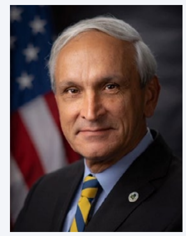
"The PUCO proceedings involve issues related the United States' investigation, and the United States believes that continued discovery in the PUCO proceedings may directly interfere with or impede the United States' ongoing investigation," Parker wrote.

In 2020, then PUC Chairman Sam Randazzo launched four separate but often interrelated investigations into FirstEnergy. In November of that year, FBI agents raided Randazzo's home and were seen leaving with boxes of material.

More: *Ohio Capital Journal*

OKLAHOMA

Gov. Stitt Appoints New Secretary of Energy and Environment



Gov. Kevin Stitt last week named **Ken McQueen** the new secretary of energy and environment.

McQueen has served as EPA Region 6 administrator and national energy policy adviser, serving out of the Dallas office, since 2019.

Former Secretary Ken Wagner announced his resignation the week prior to Stitt's announcement of his replacement.

More: *The Journal Record*

TENNESSEE

Middle Tennessee Electric Members Set Record for Electricity Consumption

Middle Tennessee Electric (MTE) set a record for electricity consumption in July, using 50 million kWh more than it did in July 2021.

"That's the most electricity we've ever provided to our membership for a month," MTE President and CEO Chris Jones said. "Air conditioning to combat the heat was far and away the biggest factor in setting that record."

To help its members, Jones said the company is suspending disconnections for non-payment and eliminating all late fees from Aug. 1 until after Labor Day.

More: *WGNS*

TEXAS

LP&L to No Longer be Electric Supplier in Lubbock

Lubbock Power & Light last week announced it will no longer serve the Lubbock market as an electricity provider beginning in the fall of 2023.

Beginning next summer, Lubbock residents and business owners will be able to select from other retail electricity providers before breaking off from LP&L in the fall. Prior to the transition, LP&L will move the remaining 30% of its customers still connected to SPP onto the ERCOT market in May 2023.

The notice comes at least 12 months prior to the scheduled launch of a competitive electric environment in Lubbock, as required by law.

More: *Lubbock Avalanche-Journal*

VIRGINIA

Skanska to Build OSW Staging Port in Portsmouth

Sweden-based Skanska, one of the country's largest construction firms, last week signed a $223 million contract with the Port Authority to redevelop 72 acres of the Portsmouth Marine Terminal for use as an offshore wind staging port.

The redevelopment of the terminal supports the Coastal Virginia Offshore Wind project, which is the largest project of its kind in the U.S.

Construction began July 2022, and completion is scheduled for 2025.

More: *Offshore Engineer*

Supreme Court Overrules Appalachian Power Rate Increase Denial

The state Supreme Court last week voted 5-2 in favor of overturning the State Corporation Commission's decision to deny Appalachian Power a rate increase.

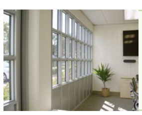
The court found that the commission erred in 2020 when it denied the company's request, saying the accounting practice in which Appalachian included the costs of the early retirement of several coal-fired power plants in 2015 to offset its earnings in 2019 was allowed by law and verified by independent auditors. The SCC had ruled that Appalachian failed to meet its burden of establishing that was reasonable.

The case on the $10 increase now goes back to the SCC for additional proceedings.

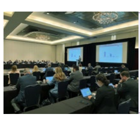
More: *The Roanoke Times*

National/Federal news from our other channels


Infrastructure Law's 2022 Funds to Double US Clean Bus Fleet — NetZero Insider


Andersen to Manufacture Energy-generating Windows — NetZero Insider


DOE Opens $45M Challenge on Grid Cybersecurity — ERO Insider


NERC FAC Approves Final 2023 ERO Budgets — ERO Insider


NERC Board of Trustees/MRC Briefs: Aug. 17-18, 2022 — ERO Insider

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