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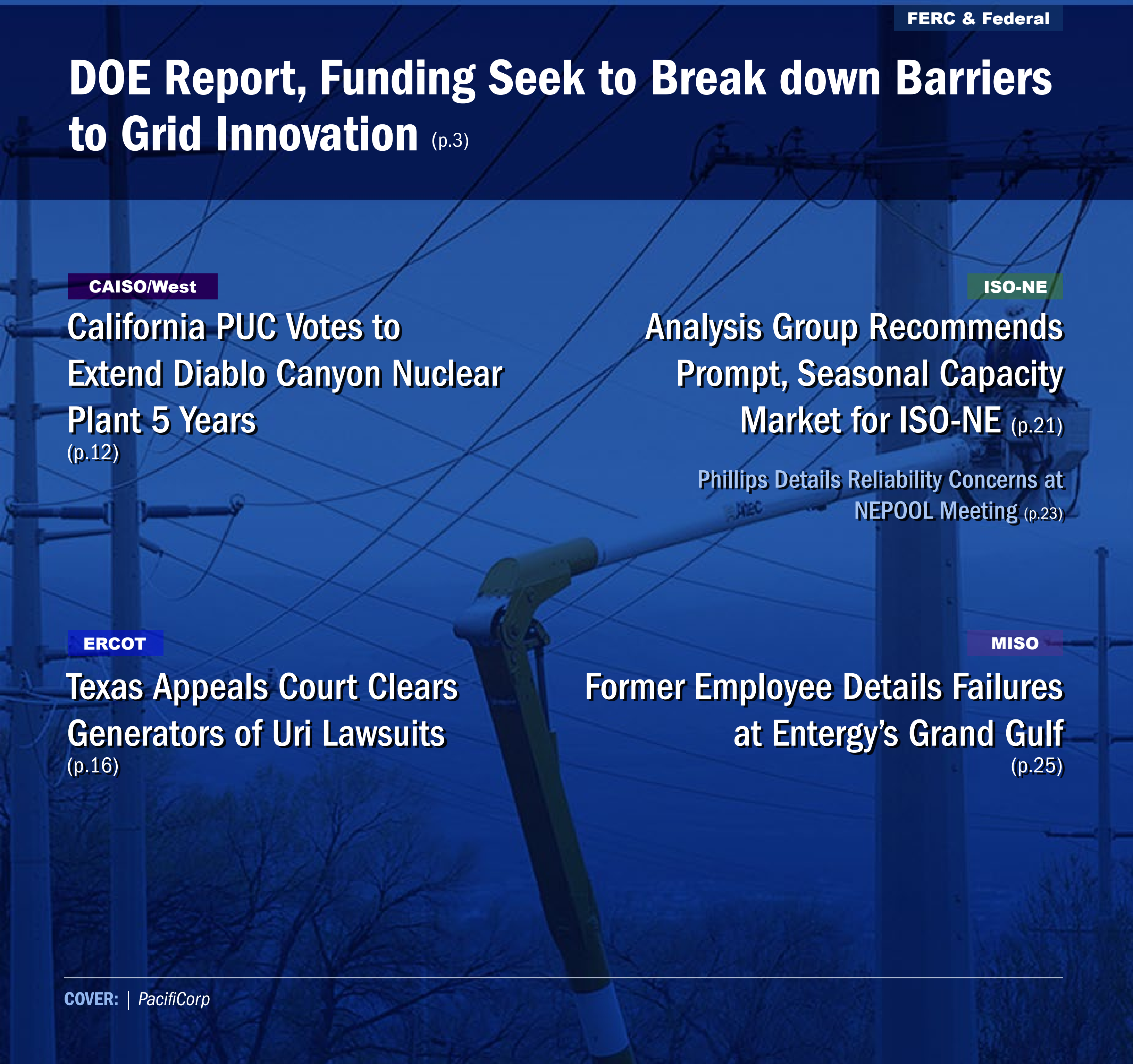
RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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



FERC & Federal

DOE Report, Funding Seek to Break down Barriers to Grid Innovation (p.3)

CAISO/West

California PUC Votes to Extend Diablo Canyon Nuclear Plant 5 Years (p.12)

ISO-NE

Analysis Group Recommends Prompt, Seasonal Capacity Market for ISO-NE (p.21)

Phillips Details Reliability Concerns at NEPOOL Meeting (p.23)

ERCOT

Texas Appeals Court Clears Generators of Uri Lawsuits (p.16)

MISO

Former Employee Details Failures at Entergy's Grand Gulf (p.25)

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Your Eyes and Ears on the Organized Electric Markets
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In this week's issue

Editor's Note

RTO Insider's staff will be taking a well deserved break for the holidays. Aside from major breaking news, we will not be publishing between Friday, Dec. 22 and Tuesday, Jan. 2. Our next newsletter will be Tuesday, Jan. 9. Happy holidays!

FERC/Federal News

DOE Report, Funding Seek to Break down Barriers to Grid Innovation

Regulators, Utilities Must Value Performance, not Capital Investment, Experts Say

By K Kaufmann

The U.S. Department of Energy looks to be preparing for a full court press on grid-enhancing technologies in 2024, with a new report and funding opportunities aimed at removing barriers to the deployment of technologies like dynamic line ratings and advanced conductors that can quickly increase capacity on existing transmission and distribution lines.

"We're entering into an extraordinary time where many parts of the country are seeing rapid load growth, generation additions and resiliency threats all at once," said Vanessa Chan, chief commercialization officer and director of DOE's Office of Technology Transitions (OTT), during a Dec. 12 webinar. "So many solutions are already sitting right in front of us. We need to get the commercially available, innovative technologies out the door on the existing system today."

The key challenges are not the maturity of specific technologies, but "deployment barriers inherent in the market structure," she said. "We need to ramp momentum. It will be a massive, massive miss if we don't work together to break these barriers down today."

Chan's call to action kicked off a preview of the department's upcoming Pathways to Grid Innovation Commercial Liftoff Report, due early in 2024, while also sending some clear messages about the kind of projects DOE will be looking for in applications for the second round of its Grid Resilience and Innovation Partnerships (GRIP) program.

"We're really prioritizing in this round of funding projects that significantly increase transmission capacity, whether they're using advanced conductors or [high-voltage, direct current lines] or grid-enhancing technologies," said Maria Robinson, director of DOE's Grid Deployment Office (GDO), which administers the GRIP program. The goal, she said, is to leverage federal funds "to catalyze a long-term transformation of grid systems and technologies."

DOE awarded $3.46 billion to 58 projects across 44 states in the first round of GRIP funding, and has announced $3.9 billion for the second round, with initial concept papers due Jan. 12. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

While the Commercial Liftoff report will cover about 20 technologies that are ready or almost ready to scale, the webinar was strategically focused on the same technologies that the GRIP program will be prioritizing — dynamic line ratings, advanced conductors, HVDC lines and advanced distribution management systems (ADMS).

All four provide the most bang for the buck, said Louise White, a policy advisor in DOE's Loan Programs Office.

| *PacifiCorp*

"When we evaluate the impact of these solutions on the grid, we see that each contributes in multiple ways to enhancing grid capacity to make the most of existing rights-of-way today and toward achieving modern grid objectives by improving systems portability, environmental sustainability, reliability, safety and security," she said.

DOE funding — from the Infrastructure Investment and Jobs Act and the Inflation Reduction Act — can buy down the high cost of the early projects needed to stimulate supply chain and further adoption, and bring down prices, she said.

Some utilities have started deploying GETs, said Avi Gopstein, a GDO senior advisor, pointing to projects such as National Grid's use of *dynamic line ratings* in New York to cut curtailment of wind projects and expand capacity on transmission lines.

But he said, "There are more than 3,000 utilities in the United States, and a few excellent projects won't get us where we need to be."

Utilities face "the competing priorities of maintaining an aging system while planning for future system upgrades, as well as the need for efficient capital allocation to minimize ratepayer impacts," Gopstein said. The need now is for "new processes to better evaluate emerging technology benefits when technology is first deployed and for a future when it is utilized at scale. …

"It's clear that legacy approaches to capital allocation, which often depend on a maintenance framework built on the foundational assumption that existing infrastructure is sufficient to serve load, are no longer adequate," he said.

Lucia Tian, a senior advisor for OTT, agreed. "Given the pressures our electric grid is facing, stakeholders across the board are emphasizing the need to shift to a proactive, future-oriented approach for managing and investing in the grid to ensure system reliability in a rapidly changing energy system," she said.

"Both industry and regulators recognize that current regulatory and business models make it challenging to invest in advanced innovative grid solutions that go beyond the maintenance of existing infrastructure and development of traditional assets," Tian said. "And the status quo here isn't an option."

FERC/Federal News

Innovation in Many Flavors

The main driver for GETs is burgeoning demand on the grid. According to new report from Grid Strategies, grid planners now see demand almost doubling over the next five years, requiring an additional 38 GW of capacity. (See *Grid Planners Predict Sharp Increase in Load Growth*.)

Expanding capacity on existing lines is critical, but accelerating deployment will require a shift in business and regulatory models to develop standards and methods for valuing the benefits GETs can provide across a system, White said. Looking at dynamic line ratings (DLR), for example, White said, the technology "drives multiple capacity, reliability, decarbonization and affordability outcomes.

"But to implement DLR requires installing sensors to measure real time environmental and land conditions, which also significantly [increases] system visibility," she said. Advanced DLR also may require automating and digitizing substations, which "will enhance line voltage and current control, amplifying DLR benefits."

New communication and data management systems also may be needed, she said, but "being strategic about investment in these infrastructures can prepare a utility to unlock additional benefits down the road and improves cost-sharing between technologies."

Still, the way forward will be different for different utilities, she said. Not everyone needs best-in-class systems.

"Innovation comes in many flavors, and considerable benefits can be realized with more basic technology investments," White said. "So, a strategic investment plan must identify the appropriate level of innovation and supporting technical requirements to best support a diverse array of future applications to meet utilities' current and future grid needs."

Angelena Bohman, a GDO technical analyst, also raised the organizational challenges adoption of new technologies can trigger. While an ADMS "increases visibility and situational awareness on the system and automates processes that exist manually today," setting up the system "requires managing the migration of old workflows and databases into the system … [and] benefits may not be realized for many years."

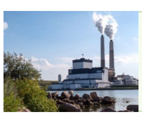
The result is a misalignment between traditional planning and valuation based on short-term profit, and the need for more forward-looking, long-term perspectives.

Deployment of advanced grid technologies suffers from "a lack of sufficient investment incentives to warrant the significant organizational effort required to deploy many of these innovative solutions," White said. "This again highlights the need to shift from traditional cost-of-service models that often disincentivize these types of innovative investments and toward business models that reward utilities for these types of investments that are needed for a modern grid."

White ended the webinar with a list of critical takeaways:

- Valuing innovative grid technologies "requires looking at the system holistically to recognize complementary and stacking benefits and to strategically plan for the long term to ensure capital is deployed efficiently today."
- Regulatory and business models must be updated to "address the meaningful misalignment between traditional incentive structures and the needs of a modern grid." New structures must "value performance instead of capital expenditure [and] enable new risk- and cost-sharing models and encourage innovation."
- Grid management also must change, from "legacy, reactive" approaches to "proactive, future-oriented strategies that serve the long-term interests of ratepayers." ■

National/Federal news from our other channels



DOE Announces $890M in IIJA Funds for CCS Demonstration Projects — NetZero Insider

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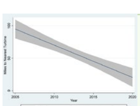

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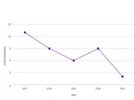
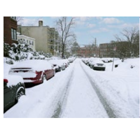


FERC's CIP Report Finds Fewer Issues Again — ERO Insider



Standards Committee Authorizes Shortened Ballots — ERO Insider

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

FERC/Federal News

Treasury Department Releases Guidance on 45X Credit for Manufacturing

By James Downing

| South Fork Wind

The U.S. Department of Treasury and the IRS on Thursday released proposed *guidance* on the 45X Advanced Manufacturing Production Credit, which is available to producers of wind and solar components, inverters, battery components and critical minerals.

The tax credit is part of the Inflation Reduction Act, which the department said already is creating manufacturing jobs.

"These new investments across industries and throughout clean energy supply chains are creating good-paying jobs and driving down the cost of clean energy for Americans," Secretary of the Treasury Janet Yellen said in a statement. "New manufacturing investments are disproportionately going to communities that have lacked opportunity and are key to increasing long-run growth and the productivity of our economy."

Treasury released a notice of proposed rulemaking (NOPR) on the 45X tax credit, which proposes clarifying definitions and confirms credit amounts for the components it covers. It proposes definitions for key terms meant to incentivize domestic production and clarifies the circumstances under which the credit can be claimed.

The NOPR includes safeguards against fraud, waste and abuse, including ways to avoid double-credits for the same component, crediting of activities that add no value and extraordinary circumstances in which clean energy components are produced but never used productively.

The tax credits will be in full effect through the end of this decade and, starting for components sold in 2030, they will ramp down to 75%, then 50% in 2031, 25% in 2032 and be phased out entirely in 2033. Only the 50 applicable minerals will be eligible for the 45X credit after 2032.

Solar energy components include modules, photovoltaic cells, photovoltaic wafers, solar grade polysilicon, torque tubes, structural fasteners and polymeric backsheets. Modules or photovoltaic cells would get a credit based on their nameplate capacity in direct current watts under standard testing conditions.

Wind energy components include blades, nacelles, towers, offshore wind foundations and related offshore wind vessels. Eligible ships would be those purpose-built or retrofitted for installing offshore wind turbines, while wind tower components would get credits based on the capacity of the completed turbines.

Both utility-scale and distributed-energy-scale inverters would be eligible for the tax credits, the NOPR said. Eligible battery components include electrode active materials, battery cells and battery modules.

Treasury also released new analysis from its economists using data from the Massachusetts Institute of Technology and the Rhodium Group showing how the IRA already has accelerated clean energy manufacturing.

Since the bill was passed, 76% of investment dollars in clean energy manufacturing have gone to counties with average weekly wages below the U.S. average; 66% are in counties with college graduation rates below the U.S. aggregate rate; 54% of investment went to counties with lower employment levels than average; and 69% went to counties with incomes below the median.

The American Clean Power Association welcomed the NOPR, noting that over the past 16 months the clean energy sector has announced 112 new manufacturing facilities that will employ more than 41,000 workers.

"Today's guidance is a critical next step for U.S. manufacturers as they work to make announced facilities a reality," said ACP Chief Advocacy Officer JC Sandberg. "By creating and expanding supply chains to make clean energy technologies here at home, we will strengthen America's energy security, create good-paying American jobs and boost the nation's economy."

American Council on Renewable Energy Vice President José Zayas also welcomed the new guidance, which he said would help clean energy manufacturing to continue growing.

"The inclusion of key components, including emerging battery technologies and offshore wind vessels, in addition to prior guidance unlocking the direct pay option for the 45X credit, provides needed clarity for our sector as we work toward achieving the enhanced domestic manufacturing base we need to meet the growing demand for clean and renewable power, secure our grid, lower costs and maximize American competitiveness," Zayas said.

Advanced Energy United also welcomed the guidance, while highlighting that it includes recycled content and allows for innovative technologies to qualify.

"By permitting recycled content, Treasury has further incentivized the development of a circular clean energy supply chain, something fossil fuels can never achieve, while also helping make imported content into American-made resources," said AEU Managing Director Harry Godfrey. "By allowing new and innovative technologies, like permitting DC-optimized inverter systems to qualify as microinverters, Treasury is ensuring that this policy encourages, rather than stifles, innovation in this dynamic industry." ■

FERC/Federal News

House Democrats Introduce Bill to Spur Interregional Transmission

By Michael Brooks

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A bill introduced in the U.S. House of Representatives by Democrats on Dec. 13 would grant FERC numerous new authorities over interregional transmission in a bid to spur large projects and increase the flow of renewable energy across state lines.

The 210-page Clean Electricity and Transmission Acceleration (*CETA*) Act, introduced by Reps. Sean Casten (D-Ill.) and Mike Levin (D-Calif.), would add six new sections to the Federal Power Act, many of them directing FERC to issue new regulations for how it can site new interregional projects. Most significantly, it would require the commission to solicit plans from grid operators and other transmission providers identifying interregional transmission projects every three years.

The bill details the criteria for how FERC would evaluate the plans and the projects they identify. The commission would be required to issue its solicitation within a year and a half of the bill's enactment.

FERC also would gain explicit siting authority over interstate transmission lines with capacities over 1 GW, if the commission finds they enable the use of renewable energy, increase reliability and reduce congestion, among other provisions.

The bill also would set new cost allocation rules for any transmission facility "of national significance," defined as a new line that has a capacity of 1 GW or more; any transmission connecting offshore generators; and upgrades that increase an existing line's capacity by 500 MW or more. Costs would be allocated "to customers within the applicable transmission planning region or regions in a manner that is roughly commensurate with the reasonably anticipated transmission benefits," the bill says.

Many of these projects would qualify for a 30% investment tax credit established by the bill. To carry out all its new responsibilities, FERC would be allowed to establish a new Office of Transmission.

"The biggest challenge facing the United States' ability to meet its climate goals is the lack of capacity of our electrical grid to connect clean energy generation to the new demand that comes with economy-wide electrification," the House Sustainable Energy and Environment Coalition (SEEC), made up of 93 Democrats, said in a *press release*. "CETA aims to inclusively and efficiently support the buildout of transmission lines to transport the electricity from its generation source to the homes of the American people."

The release included *statements of support* from former FERC Chair Richard Glick, Grid Strategies' Rob Gramlich, Americans for a Clean Energy Grid, the American Clean Power Association and several environmental organizations.

"The CETA Act is an important step in addressing some of the most pressing issues around transmission capacity and the diverse technologies that can deliver solutions at speed and scale," AES said in a statement. "We commend the efforts of the SEEC caucus on this thoughtful bill, which aims to reduce bottlenecks and improve planning of and connection to the transmission system."

The bill also would incentivize development of solar, wind and geothermal resources on public lands and establish a production goal for such resources of at least 60 GW by the end of 2030. It would direct the Department of Agriculture, in consultation with the Department of Energy, to identify priority areas for solar and wind.

Finally, CETA would codify President Joe Biden's goals for offshore wind deployment, directing the Department of the Interior to issue permits for a cumulative of 30 GW by 2030 and 50 GW by 2035. It also would establish an Offshore Renewable Energy Compensation Fund in the Bureau of Ocean Energy Management "to compensate eligible ocean users for damages experienced as a result of the development of an offshore renewable energy project through a claims-based process and to provide grants to eligible recipients to mitigate future damages from such projects."

With Republicans in control of the House, the bill has virtually no chance of passing as drafted. And the increased authority it would grant to FERC is likely to draw some opposition from states both red and blue, along with their utilities.

The permitting reform debate has been on apparent hiatus for months, as the House battled over the speaker position and the debt ceiling. Several bills have been introduced in both houses, but none has been viewed as a starting point for party negotiations. The last hearing by the Senate Energy and Natural Resources Committee on the subject was held in July. (See *Members of Congress Debate Transmission Permitting*.) ■

FERC/Federal News

NERC: Growing Demand, Shifting Supply Mix Add to Reliability Risks

Long-Term Reliability Assessment Finds PJM Only RTO Without Elevated Risks

By James Downing

Rising demand and the potential for higher generator retirements are raising reliability concerns over the next 10 years, NERC said in its 2023 *Long-Term Reliability Assessment*, released Dec. 13.

"In our latest assessment, it really confirms that we're in an absolute step change in terms of the risk environment we're seeing on the system, both in terms of reliability, as well as energy assurance," John Moura, NERC director of reliability assessment and system analysis, said on a webinar with reporters. "The electric power industry continues to face challenges in the future: a rapidly changing resource mix, threat landscape, extreme weather and inverter-based resources."

Moura said ensuring reliability as the resource mix changes involves stopping plants from retiring early and making sure new resources can provide enough of the same needed services.

Peak demand net energy growth rates in North America are growing more rapidly than at any point in the past three decades, according to the LTRA. Electrification of heating and electric vehicles, as well as increased demand from commercial and industrial customers such as data centers, has reversed the decadeslong trend of falling or flat growth rates.

The aggregated summer peak demand forecast is expected to grow by 79 GW over the next 10 years, while winter demand growth is expected to rise by nearly 91 GW in the decade. Winter demand is growing so fast that NERC expects the Northeast and Southeast to become winter-peaking, or at least dual-peaking, in the coming years.

The supply side is seeing overall growth, dominated by solar power, while fossil generation is expected to decline in the coming decade.

"We are projecting moderate growth," NERC Manager of Reliability Assessments Mark Olson said. "But it's not quite keeping up with where the demand projections are going in this most recent forecast that we received. Our total capacity growth is expected to be about 34 GW over the next 10 years."

New England and New York are expected to have higher winter peaks by the mid-2030s, while the Southeast has already gone through changes.

"SERC-Central and SERC-East became dual-peaking systems in recent years," the report says. "SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer."

SERC-Central, made up of six states centered around Tennessee, joins MISO as one of the two "high-risk areas" in NERC's report. That means they are more likely to have insufficient supplies to meet demand at some point in the next decade.

Despite its high risk, MISO has actually improved since last year, when shortages were expected this year, but delayed retirements and some new resources now have NERC expecting a 4.7-GW shortfall in 2028. SERC's shortfall is expected to hit in 2025-2027 as the region retires 5 GW of coal and brings online 7 GW of natural gas.

Many more regions were "elevated risk areas," meaning NERC is not worried about them in normal weather, but their systems could run into issues under extreme conditions. Five of the ISO/RTOs are included in the category.

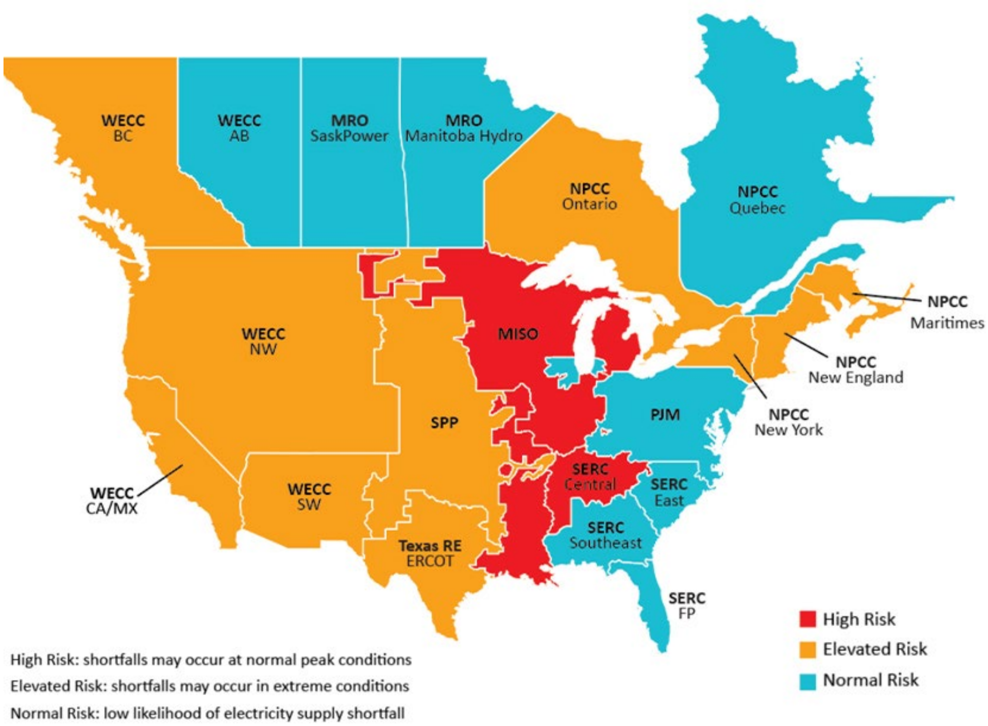
California has also improved because of new capacity additions, as now NERC is expecting negligible risks next summer, but it warns by 2026 that unserved energy risks emerge in the summer.

ERCOT is seeing huge additions of solar power but faces elevated risks during the off-peak periods when its output is lower. Those risks are during peak summer days, and when dispatchable generation is down for maintenance in the shoulder months. Extreme winter weather is also still a concern and warrants continued efforts ensuring generators and the fuel they need to keep running remain available.

New England continues to face elevated risks in the winter with persistent concerns about fuel availability being exacerbated by electrification as its winter peak demand growth rate is the highest in North America, with a 3.46% compound annual growth rate over the next decade.

NERC confirmed NYISO's own reliability studies, which show a risk of shortfalls for New York City starting in 2025 as peak demand rises and generators become unavailable because state laws reducing the emission of nitrogen oxide.

SPP has a surplus now, but it is going to drop rapidly over the next few years because of



NERC's map showing the risk levels for reliability by region | *NERC*

FERC/Federal News

retirements and rising peak demand. The RTO also raised its reserve margin from 16% to 19% in the past year.

The only RTO to have a normal risk level — meaning NERC expects its system would handle even extreme conditions — is PJM. While NERC's forecast has healthy reserve margins in PJM throughout the decade, it noted that accelerated retirements and higher demand growth could still pose challenges in the later years of its assessment.

Ultimately, the shortfalls NERC identified in its report can be resolved with additional procurements of supply, Olson said.

The power industry's ongoing transition is playing a role, as the move to net-zero emissions is driving electrification that is pushing up demand and is also changing the resource mix on the supply side of the equation. The industry, policymakers and regulators all have to balance reliability with affordability and addressing environmental concerns, Moura said.

"I think when we get tripped up is when in how we prioritize those," he added. "And so, reliability is something that needs to be prioritized. It's the heart and soul, for the health, safety and the prosperity of our consumers and all of our communities. And so that needs to be at the heart of it."

As policy continues to move forward on net-zero issues, reliability must not be forgotten, and the industry needs to continue focusing on it, Moura said.

Reactions to LTRA Highlight Risks

National Rural Electric Cooperative Association CEO Jim Matheson put out a statement saying EPA's proposal to curb emissions from power plants would only exacerbate the situation NERC's report highlights.

"NERC's latest assessment paints another grim picture of our nation's energy future as demand for electricity soars and the supply of always-available generation declines," Matheson said.

The coal power trade group America's Power also used the report to highlight its qualms with recent energy policies.

"Unfortunately, NERC's latest assessment is deeply troubling because it indicates that, despite several years of warnings about the possibility of electricity shortages in many parts of the country, the risk of electricity shortages has grown worse," said America's Power CEO Michelle Bloodworth. "This is largely due to coal retirements, EPA policies and dangerous subsidies for unreliable sources of energy. We again urge Congress and federal and state policymakers to act immediately on these continued warnings."

On the other side of the debate, the World Resources Institute held a webinar earlier in the day to highlight a new working *paper* on how to maintain reliability throughout the clean energy transition. Author Kelli Joseph, WRI senior fellow, noted it was more focused on operating reliability, while the LTRA is all about resource adequacy.

"We don't spend as much time talking about operating reliability," Joseph said on a webinar. "And I think what we need to recognize going forward, especially through the transition, is that operating reliability becomes a bit more challenging."

Operating reliability refers to the ability of the system to withstand sudden disturbances, which many of NERC's mandatory standards address.

If anything, the clean energy transition is going to make reliability more important, as more of the economy is connected to the grid through electrification, Karen Palmer, director of Resources for the Future's electric power program, said at the WRI event.

"But it's also important in the near term for continued progress on electricity sector decarbonization," Palmer said. "Any reliability events or outages or mandatory load-shedding events that could be in any way pinned on decarbonization efforts, rightly or wrongly, could really stall clean energy progress in its tracks. And that wouldn't be good for meeting domestic and international climate targets." ■

FERC/Federal News

Report Dives into the Details of Electricity Restructuring

By James Downing

Electricity restructuring is often discussed as a binary — either a state uses market forces, or it does not — but a recent webinar from the Energy Choice Coalition dove into all the complexities it has led to since it started in the 1990s.

While individual states all have their own unique mix of rules, the R Street Institute's *paper*, "Electric Paradigms: Competitive Structures Benefit Consumers," puts them into three categories: 18 traditionally regulated, 19 with a hybrid system of wholesale competition and no retail, and 14 (including D.C.) with both wholesale and retail competition.

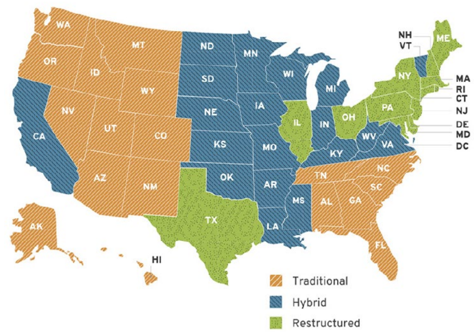
"We wanted to diagnose that as sort of a basic fact about the current system," Michael Giberson, R Street senior fellow and the report's co-author, said on the webinar. "And then we wanted to see for each of these three systems, how does the evidence stack up in terms of how they're serving customers."

The report dives into details around how markets have been viewed as saving or costing money for customers; how they have impacted reliability; and their environmental outcomes. It summarizes numerous other studies from both sides of the argument.

"Restructuring, when done well, has done well," the paper says. "Restructuring likely benefits reliability, reduces emissions and unleashes efficiencies at the wholesale level that get passed along to consumers when retail competition is allowed to work."

Most of the change in recent years has come from states joining MISO and SPP but not deregulating their retail sides. That trend is ongoing in the West with discussions around market alternatives, but Meghan Nutting, Sunnova Energy executive vice president of government and regulatory affairs, said technological change has made generation monopolies at the retail level functionally nonexistent.

"Because of rooftop solar, and because of other technologies and alternatives that consumers have, it means they don't have to rely solely on their monopoly generation provider for electricity," Nutting said. "And so, the more that regulators and the more that our government structures try to support and protect those former generation monopolies, that's just protectionism of individual companies at this point, because there is competition within their market."



| R Street Institute

Retail competition has seen pushback in some states like New York and Massachusetts because retailers were offering higher prices than the standard offers from the utilities, which for the most part in restructured states were left as providers of last resort (POLR) for mass-market customers. Only Texas eliminated the utilities' POLR role in its market, which even then is only inside ERCOT and only required of investor-owned utilities (leaving out Austin, San Antonio and other cities served by municipally owned utilities).

The paper says that critics of those higher-priced contracts have identified "valid problems" with the markets that can be fixed with better rules, such as improved licensing processes and oversight. It calls on states to move to "better paradigms" — i.e., those in hybrid states moving to full restructuring.

"When moves to a better paradigm are impossible at present, policymakers should seek out improvements within existing structures," the paper says. "Importantly, even policymakers in fully restructured states have opportunities to improve competition within that paradigm as well."

Moving toward more competition takes "significant decisions away from utilities and regulators" and places them in the private sector. Regulators are ostensibly supposed to make decisions that take into account the interests of consumers and other groups, but the paper notes that process can be corrupted in ways the market cannot, citing recent scandals with traditionally regulated utilities influence peddling, bribing officials and intimidating journalists.

"What we're seeing is competition within these spaces that exists already, protectionism for the incumbent, and then inadequate regulation in place of markets that would allow consumers to drive the outcomes that would likely be better," Nutting said.

Regulators have to make sure that utilities do not give into the economic incentive of investing in higher-cost resources to earn higher returns, while markets outright offer the opposite incentives, said Lynne Kiesling, director of Northwestern University's Institute for Regulatory Law & Economics.

"If I come in with a lower-cost technology, and I'm competing in a market against higher-cost technologies, I'm going to earn more profit, because I'm lower-cost," Kiesling said. "And that incentive is very, very powerful, and it benefits both producers and consumers."

The paper highlighted how that effect of markets can influence environmental outcomes, as they have favored natural gas plants and renewables over coal.

"An earlier study found that reductions in natural gas prices and the growth of wind power both contributed to the decreased use of coal plants in RTOs, with a resulting reduction in carbon emissions," the paper says. "The effects pushing emissions down were weaker in SPP, which researchers speculated was caused by the ways in which monopoly-owned generators — dominant in SPP — respond to market incentives as compared to non-utility generators."

Natural gas prices have had major impacts on markets in other ways, with the report suggesting that the outcome of lower prices in retail markets depends on a state's access to cheap supplies of the fuel.

A soon-to-be-published study in The Energy Journal has found mixed results with retail competition's prices — finding they have gone higher in four of the five restructured states in New England while falling in Pennsylvania and Texas, the R Street paper says.

"Both Pennsylvania and Texas were well positioned to access cheap natural gas resulting from advanced drilling techniques like fracking," the paper says. "New England, on the other hand, has limited ability to bring in domestically produced natural gas and must resort to importing expensive liquefied natural gas to run natural gas generators during periods of high gas demand." ■

FERC/Federal News

Searching for Paradigm Shifts in Distribution Planning and Financing

GridCONNEXT Panels Call for Forward-Looking Strategies to Meet Burgeoning Power Demand

By K Kaufmann

At gridCONNEXT, from left: Phil Dion, EEI; Peter Fox-Penner, EIP; moderator Chris Guttman-McCabe, Anterix; and Karen Wayland, GridWise Alliance, talk about financing the future grid. | *© RTO Insider LLC*

WASHINGTON — As utilities and regulators face unprecedented growth in power demand — from data centers, chip and other clean tech manufacturing, and building and transportation electrification — figuring out how to plan and finance distribution systems has become a similarly fast-moving target, according to speakers at the GridWise Alliance gridCONNEXT conference.

The industry now faces a "trilemma," attempting to balance decarbonization, reliability and affordability, said Peter Fox-Penner, partner and chief impact officer at Energy Impact Partners (EIP), a clean tech investment firm funded by utilities.

"There are many related challenges of decarbonizing supply, doubling the size of the grid, while … incorporating AI, severe weather, institutional distrust and other things," Fox-Penner said during a Dec. 6 panel on how to draw more, and more diverse, investment into grid expansion.

The effects of extreme weather, exacerbated by climate change, also are becoming a major challenge to the economic viability of utilities, he said. Citing figures from a recent analysis from Fitch, Fox-Penner noted that extreme weather events caused close to one quarter of the rating agency's downgrades for utilities between 2018 and 2023 (year to date) versus none in the previous five-year period.

A shift is needed in the industry's and consumers' understanding of affordability, away from cost per kilowatt-hour on electric bills toward "wallet-share," the amount households spend on electricity "versus everything else," he said.

While electric rates certainly have been hit by inflation, wallet-share is at 1950s levels and even fell slightly in 2022, he said. "Affordability is a tremendous challenge … because of the macro environment we're operating in, rather than the fact that electricity remains an incredible value."

Prices will come down with new and better technologies for electrifying transportation and buildings, he said.

A paradigm shift also is needed in utilities' approach to distribution planning, which typically runs in two- to five-year cycles, with system upgrades made incrementally, on an as-needed basis, said Jeff Smith, director of transmission and distribution operations and planning at the Electric Power Research Institute (EPRI).

"But if we keep doing that sort of incremental approach, will that lead us to a suboptimal location later down the road? … Is that something we're going to regret doing by 2040, 2050?" he said.

Working with the Department of Energy and utilities, EPRI is trying to ask different questions, Smith said during a panel on distribution planning. The goal here is to "take that long-term look and identify the grid service needs, the grid design requirements, the operating requirements that are necessary for deep decarbonization," he said.

Industry stakeholders and their concerns appear endlessly complex, Smith said — how many transformers will be needed, when and how to introduce time-of-use rates, how to integrate storage — "but we can't let analysis paralysis stop us from moving forward. … The needs of the grid are changing at a pace we've never seen before."

Distribution system design and projections of load growth typically have been based on historical information, Smith said. "We need to start looking to the future. … Our loads are changing, demand is changing, the shapes are changing, the flexibility of resources are changing. How does that change actually [affect] our design?"

Larry Bekkedahl, senior vice president for advanced energy delivery at Portland General Electric (PGE), also called for a closer focus on load, rather than the typical industry focus on generation capacity.

"You've really got to move and advance yourself to pick up these loads," Bekkedahl said, noting the Portland area is producing 15% of all the computer chips manufactured in the U.S., with more chip plants and data centers on the way.

"When I think about our load, we right now have over 2 GW of requests on a 4.5-GW system," he said. Demand is growing at 4% a year, versus a previous rate of about .5 to 1% a year.

"How do you plan for that? Because there's a lot of two-way, bidirectional energy that's going to be happening on the distribution side," Bekkedahl said. "What we're trying to do is bring the peaks down and push utilization up. That's our motivation, and we want to use the system we have as much as possible but drive those peaks down wherever possible."

Retrofit Everything Everywhere

The speed of change and its impacts on the electric power industry were core themes for both panels.

Fox-Penner sees "two distinct waves of [load] growth that are different in nature." In the near term, artificial intelligence, cryptocurrency and other high-tech applications will produce "very lumpy" demand curves, while transportation and building electrification will take longer, but drive bigger growth, he said.

"It's worth keeping those two things in mind, I think, because the policy responses … and

FERC/Federal News

the forecasting techniques we want to use are different," he said.

They also will draw different investors, said Karen Wayland, CEO of the GridWise Alliance, noting that high-tech companies — such as Google and Microsoft — are pouring major investments into clean energy for their data centers. But the cost of building and transportation electrification likely will fall on utilities and their customers.

Wayland also said she believes the industry has the technology to meet anticipated load growth and is "looking in both the right places. We're looking [at] developing utility scale. We're looking for local resources."

Phil Dion, senior vice president for customer solutions at the Edison Electric Institute (EEI), the industry trade group for investor-owned utilities, said he believes utilities will prioritize investments in familiar, low-risk priorities — retrofitting "everything we have as fast as possible," energy efficiency and demand-side management and flexibility.

"The idea of building transmission lines is imperative, but it's a way up. It's a decade away," Dion said. "So, we need to be investing in technologies, anything we can do to squeeze 10% more [electricity] out, without compromising safety."

Wallet-share notwithstanding, consumers' perceptions of power affordability may affect utilities and regulators' willingness to invest in the infrastructure needed to electrify everything, everywhere, he said.

The cost of expanding distribution will fall primarily on utilities — and require regulatory approval — Dion said, so, "if we don't start leveraging other piles of capital, this is going to be a problem."

DOE's Grid Resilience and Innovation Partnerships program — which recently awarded $3.46 billion for transmission and distribution system upgrades — is a step in the right direction, he said, but more money will be needed, including "leveraging customer capital as well."

Smith argued for a focus on right-sizing distribution systems, since under- or over-sizing could result in added expense and underused or stranded assets. Right-sizing also means making sure infrastructure is built in the right location, at the right time, he said.

Challenges ahead include figuring out "how do we actually make a substation expandable … sizing them appropriately for the future" and making decisions about primary voltage levels, he said. Voltage levels range from 4 kV to 34.5 kV, with most utility distribution systems in the U.S. working at 15 kV.

"The questions we need to be asking ourselves is, for 2050 [clean energy goals], is 15 kV going to get us there?" Smith said. At 34.5 kV, "you can serve much more customers from a [distributed energy resource] and load perspective, and that's why so many utilities are looking at maybe dual voltage transformers, recognizing that the voltage they're using now isn't something they're going to use later down the road."

'Every Ounce of Flexibility'

As presented by Bekkedahl, PGE is a case study in the challenges utilities face in distribution planning in an extremely fast-changing energy landscape.

The utility was able to ride out Oregon's asphalt-melting heat wave in the summer of 2021, just barely, he said. "We hit saturation; there was nothing else to turn on. We hit a flat peak … and we were kind of stunned by it, and we survived it, and the next summer, when it's 95 degrees, we were almost at the same level because everybody went out and bought air conditioners."

PGE has shifted from a winter-peaking to a summer-peaking system, and it also has been contending with south-to-north, very cheap energy flows from California, requiring quick curtailment of that power at the state border to protect the utility's distribution system from overload, Bekkedahl said.

"If you're in a dispatch room and you've got this big red screen in front of you that's saying you've got to start curtailing customers, you've got to do something," he said. PGE was able to call on 90 MW of demand response to shave its peak, which "made the difference in that moment. So, I want every ounce of flexibility I can get in the future."

Looking ahead, Bekkedahl outlined the "big five" must-haves for successful distribution planning, beginning with visibility.

"You've got to be able to see into [the system] and think about the influence that you have," he said. "If you don't have visibility into your distribution system, none of this works. You're going to build your plan, it's going to be for the peak, it's not going to be something that's flexible."

Better forecasting is next, followed by flexibility. In the home of the future, "every device is going to have intelligence," Bekkedahl said. "How are we using them? How are we interfacing with them?"

Resiliency and redundancy — backup systems — come next, with Bekkedahl pointing to inverter-based systems as one way to keep household electricity running in the event of a power outage, and possibly to provide demand response.

The last must-have is power quality, with a basic paradigm shift that can take into account and monitor the performance of the thousands of devices being turned on and off across the system, he said.

De-risk, Decarbonize, Scale

Looking ahead, Fox-Penner anticipates that distribution upgrades and expansion could be the top draw on utility investments over the next decade. "And that's where you hit resilience and affordability issues, and so that takes working with [existing] conditions, using every single tool," he said.

For utilities, part of the challenge is the regulatory limits on their ability to plan and order equipment for the future, Dion said. "Imagine you're a distribution full-time provider … and you're sold out through 2026. You have nothing," he said.

"We need regulatory regimes that allow us to make purchases into the future, not just replace the stuff that's broken, but … the new stuff that needs to be developed for what we need, almost like a hedging policy," he said.

"[We] have to be able to invest in things that we need that are facing the biggest barriers," Fox-Penner agreed, pointing to building electrification as one sector that will be critical for both homeowners and apartment renters. "That's right at the heart of our existence, and we need to go in there and change the heating and cooling system," he said.

He sees continuing innovation as key, "particularly in the spaces where the solutions aren't well developed, which are often called … the supplemental power sources to wind and solar," such as nuclear, geothermal or carbon capture.

With its funding from utilities and other investors, EIP has developed a model that focuses on investing in technologies that utilities will need and can pilot and then scale, Fox-Penner said. The company has more than 100 businesses in its portfolio and "over $1.4 billion worth of business going on between our portfolio companies and the members of our coalition," he said.

"I think of the industry as a fast follower," he said. "Our model is to de-risk decarbonization measures for our incumbent investors. Once it's de-risked, it can scale." ■

CAISO/West News

California PUC Votes to Extend Diablo Canyon Nuclear Plant 5 Years

Final Approval Dependent on Costs, NRC Signoff

By Elaine Goodman

California utility regulators on Dec. 14 approved extending operations at the Diablo Canyon nuclear power plant through 2030, a move intended to bolster reliability as the state continues its clean energy transition.

The California Public Utilities Commission voted 3-0 to authorize an extension for Diablo Canyon, which is owned and operated by Pacific Gas and Electric. The 2,200-MW power plant provides about 9% of California's in-state generation.

Diablo Canyon had been slated to close in stages in 2024 and 2025. But state officials, including Gov. Gavin Newsom (D), called for keeping the state's last nuclear power plant open to support reliability. Energy shortfalls led to rolling blackouts in California in August 2020 and close calls in subsequent summers.

Senate Bill 846, which Newsom signed in September 2022, directed the CPUC to authorize an extension for Diablo Canyon by Dec. 31, 2023. The bill described the extension as a "stopgap" measure of up to five years aimed at improving energy system reliability while more renewable and zero-carbon resources come online.

The extension approved by the commission runs through October 2029 for the power plant's Unit 1 and October 2030 for Unit 2.

CPUC President Alice Reynolds noted that SB 846 included detailed directives for the commission to follow.

"We're doing as much as we can to move quickly to reduce and eliminate the use of fossil gas to generate electricity while ensuring reliability and controlling costs for ratepayers," Reynolds said before the vote. "But we're also considering this decision before us today at the direction of the legislature."

PG&E still needs approval from the Nuclear Regulatory Commission to extend operations. The company filed a license renewal application with the NRC on Nov. 7.

CPUC plans to continue evaluating the costs of the extension as more information comes in, and whether those have become "too high to justify incurring," as SB 846 directs. Additional costs could include the expense of meeting conditions for NRC license renewal or implementing recommendations of the Diablo Canyon Independent Safety Commission.

In making its decision, the CPUC considered a report from the California Energy Commission (CEC) on whether the Diablo Canyon extension was needed to support reliability.

The analysis, completed in February, found that ordered procurement is sufficient to meet current resource adequacy planning standards through 2030.

But shortfalls are possible if the state experiences heat waves similar to those in 2020 or 2022, the report concluded. That risk is even greater if wildfires reduce transmission capacity at the same time.

In addition, new clean energy resources might be delayed due to supply chain, interconnection and permitting problems. Another issue is the ability of load-serving entities "to secure imports in an increasingly competitive Western market," the report said.

"Extending [Diablo Canyon] has a decided advantage in the sense that it is a firm, low-carbon resource," the CEC report said. "This extension allows the state to rely less on natural gas and more on clean resources for the grid."

Before the vote, the CPUC heard from members of the public who opposed a Diablo Canyon extension due to concerns about the risks of earthquakes, terrorism or sabotage.

One speaker, who lives near the central coast nuclear plant, said the state has plenty of renewable resources and battery storage to meet its energy needs.

"Why put us at risk when we no longer need the nuclear plant?" she asked.

But others supported a Diablo Canyon extension, saying the state will rely more on natural gas resources if the nuclear plant closes.

One speaker said shutting down Diablo would be inconsistent with a *pledge* by the U.S. and more than 20 other countries during COP28 this month to work toward tripling global nuclear energy capacity by 2050. ■

Diablo Canyon Power Plant sits on the coast of Central California. | *PG&E*

CAISO/West News

CAISO DMM: High Exports to Southwest Led to July EEAs

By Ayla Burnett

High levels of self-scheduled exports out of CAISO's balancing area to support stressful conditions elsewhere led the ISO to declare level 1 energy emergency alerts in late July, the Department of Market Monitoring explained this month.

The alerts, issued for July 20, 25 and 26, were not related to bad weather conditions in California, but actually in areas to its north and south, said Ryan Kurlinski, senior manager of market and policy analysis with the DMM.

Typically, during peak net load hours in the summer months, power flows from the Northwest into the rest of the system. But this July saw relatively low hydro conditions in the Northwest compared with relatively high ones in California. This was coupled with extremely high temperatures in the Southwest that lasted even after peak net load hours, leading to record demand there.

"What we saw this year was a significantly different pattern from previous years," COO Mark Rothleder said. "What we saw was a higher level of exports and demand outside of our system, and for a large period of time, we could support that demand, but there were times … where we could not."

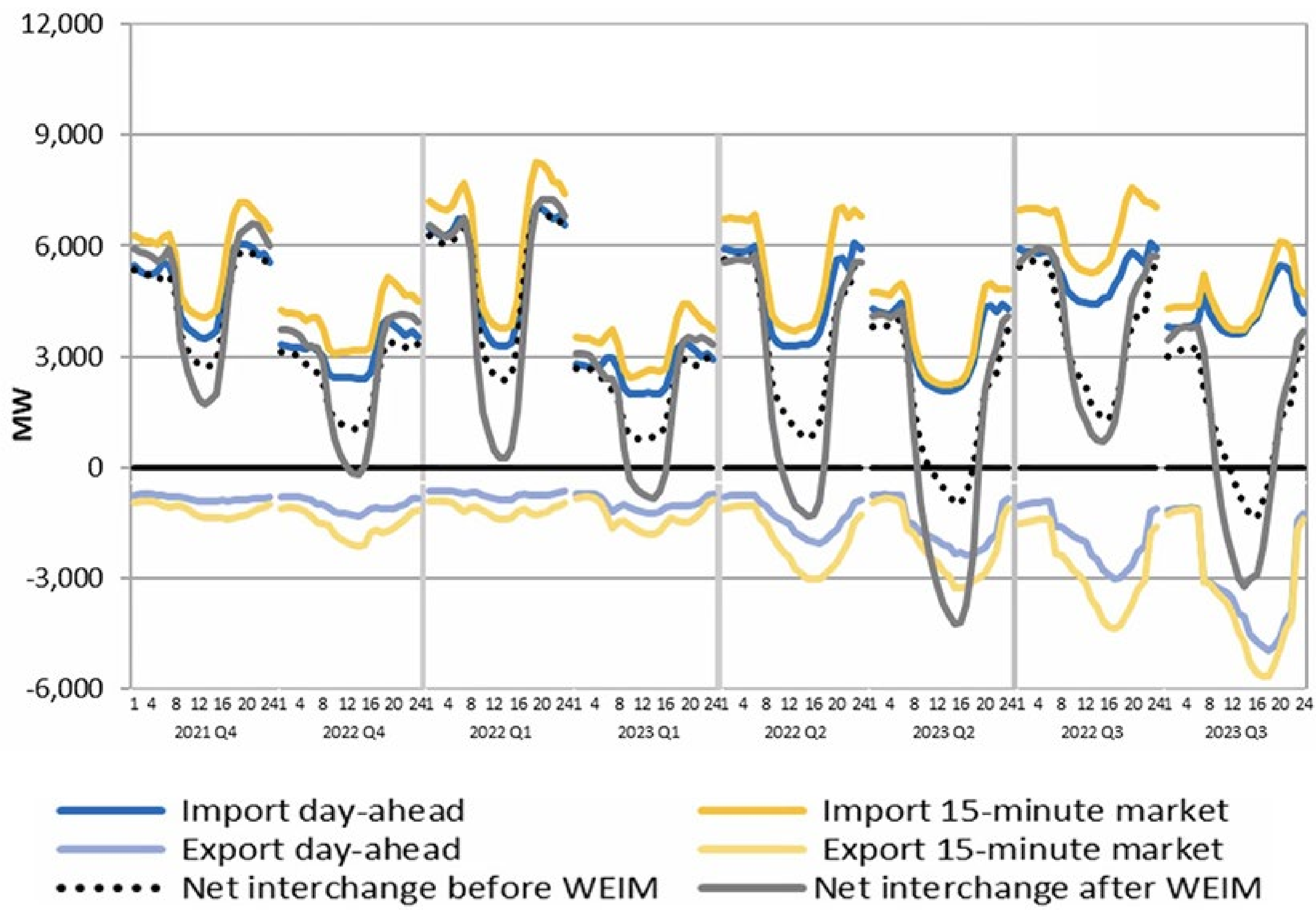
When the EEA was declared on July 20, CAISO operators had not yet identified exports they were unable to support in the hour-ahead market. As solar began ramping down, there was still relatively high demand across the system between 6 and 8 p.m. Throughout the day, CAISO had sufficient bids from its contracted capacity to cover its own requirements, but beginning around 8 p.m., "the addition of the exports required CAISO to rely on bids from resources not contracted to serve CAISO load," Kurlinski said.

While the ISO was close to being unable to deliver exports that had received hour-ahead market schedules, operators ultimately did not curtail any load.

On July 25 though, CAISO was unable to award several thousand megawatts of self-scheduled exports between 6 and 9 p.m.

"I'm calling that the first significant market issue impacting WEIM [the Western Energy Imbalance Market] in this period," Kurlinski said. "CAISO did not give hour-ahead market awards to all exports that wanted to self-schedule in the hour-ahead market."

Each of the three real-time markets have a load forecast that the market solves for, and operators frequently adjust this load above



During the July 2023 Energy Emergency Alert, CAISO saw unprecedented levels of exports, while imports decreased. | *CAISO*

CAISO/West News

the forecast, particularly during net peak load in the hour-ahead and 15-minute markets to cover any uncertainty over available supply. Uncertainty materialized quickly on July 20, Kurlinski said, and by July 25, operators began dramatically increasing the load adjustment.

"These large hour-ahead market load adjustments contributed significantly to the large quantity of exports attempting to self-schedule out of CAISO that did not receive hour-ahead market awards," Kurlinski said, but "CAISO operators did actually end up allowing a decent portion of these exports to tag … and ultimately flow to other balancing areas."

Not enough supply could prevent the hour-ahead market to self-schedule exports, but the load adjustment can also be supplied by advisory WEIM transfers flowing into CAISO's balancing area. If the transfers don't flow into CAISO in the five-minute market, however, the ISO may not have enough supply to meet load requirements and self-scheduled exports in the hour-ahead market.

"This concern arose on July 25, and my understanding is that it prompted the CAISO balancing area to start limiting the WEIM transfers into its area in the hour-ahead market," Kurlinski said. From 7 to 8 p.m., the ISO put a 4,000- to 5,000-MW load adjustment into the market, and while much of it was supported by WEIM transfers in the hour-ahead market, almost no five-minute transfers flowed into CAISO.

On July 26, CAISO started strictly limiting WEIM transfers into its balancing area during peak hours, which marked the second significant issue.

The limit significantly impacted transfers in other WEIM areas, such as in Arizona, where transfers to CAISO from Arizona Public Service decreased to zero at one point.

Observations and Lessons Learned

Rothleder shared observations that could help the ISO prepare for any similar conditions in the future, should they arise.

"Between the 20th and the 25th, we took the learnings and the observations, and we applied that [in the 7 p.m. hour] on the 26th," Rothleder said. "This is what triggered us to limit the amount of transfers the California ISO was relying on from others when we were clearing that hour-ahead scheduling process."

Limiting transfers, he said, helped reduce uncertainty and increase confidence in the ability to serve load. He also highlighted that the load adjustment aided in dealing with additional uncertainty.

Unusual conditions led to the issuing of the EEA, but all things considered, Rothleder emphasized that it was a successful summer overall for the ISO.

"It's unprecedented that we would be a net exporter in a summer period, but this past July, we saw periods where we were a large net exporter supporting other parts of the West as they were approaching 96% of their record load outside of the ISO," he said.

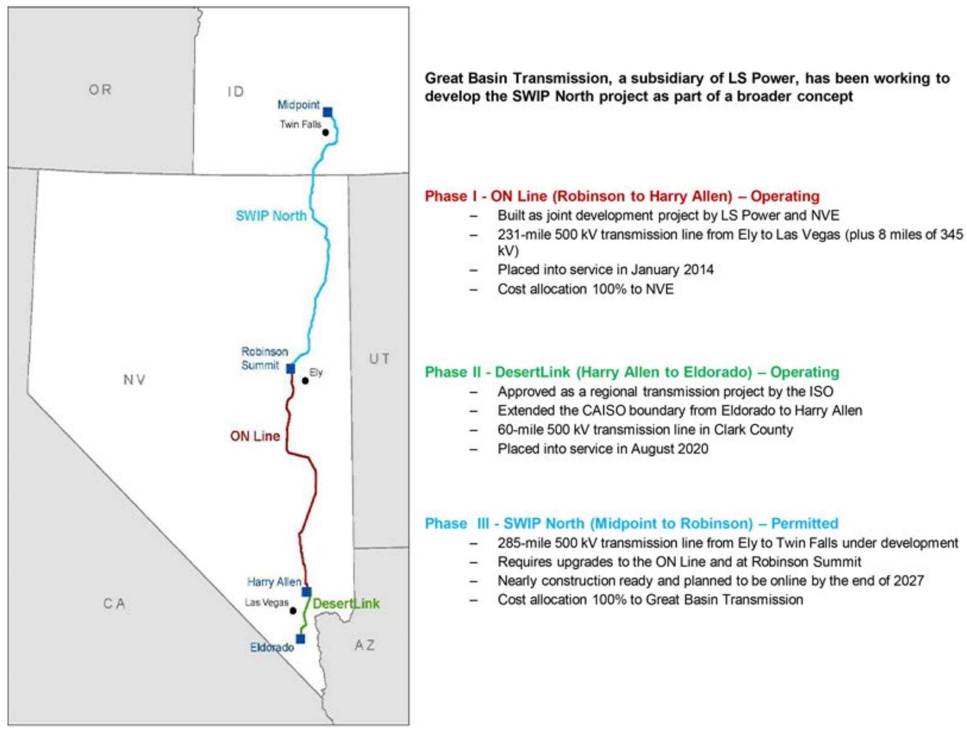
While CAISO did enter a few EEA watches and declared the level 1 alert, it did not have to issue any flex alerts or experience any load-shedding events.

"The system is becoming more complicated, and we're seeing flow patterns that are significantly different from historical patterns, and this highlights really the need for that coordination and awareness of the constraints that may arise earlier," Rothleder said. "That's why we believe things like the Extended Day-Ahead Market provide the vehicle for that strong coordination, awareness and insurance." ■

CAISO/West News

CAISO Board Approves Nevada Transmission Line to Access Idaho Wind

By Ayla Burnett



| *CAISO*

CAISO's Board of Governors on Dec. 14 approved including the Southwest Intertie Project-North (SWIP-N) — a 285-mile, 500-kV line in Nevada that would enable access to Idaho's wind resources — as an addendum to the ISO's 2022-2023 transmission portfolio.

The project is the only proposed line that would connect California's load-serving entities to Idaho wind power. (See *CAISO Pursuing Approval of New Line to Tap Idaho Wind*.)

"This is a really exciting opportunity to open up some ... really valuable resource diversity index straight to the California [Public Utilities Commission]'s integrated resource plans ... and build on that legacy of transmission connectivity they have across the West," CAISO CEO Elliot Mainzer told the board before its vote.

The approval of SWIP-N diverts from the standard transmission planning process. The board had already approved the ISO's transmission plan in May. (See *CAISO Board Adopts Revamped Transmission Plan*.)

"This is a unique project, and it has quite a few differences from a conventional transmission plan approval decision ... both because of the nature of the project and because of our negotiated arrangements with Idaho Power to access the capacity jointly," Neil Millar, CAISO vice president of infrastructure and operations planning, told the board.

The project would require CAISO to assume entitlements from LS Power subsidiary Great Basin Transmission (GBT) on the existing One Nevada Transmission Line, which connects to the ISO via the Harry Allen substation north of Las Vegas. SWIP-N would connect with the existing line at the Robinson Summit substation near Ely, Nev. Both the ON Line and Robinson would need upgrades to accommodate the new project.

SWIP-N could be online by 2027, but the board's approval is conditional on the Idaho Public Utilities Commission's by Sept. 30. The CPUC would also have to reaffirm the need for Idaho wind power as part of its consideration of CAISO's 2024-2025 transmission plan. And FERC would have to approve GBT's tariff as a participating transmission owner and transmission revenue requirement.

Assuming everything is approved, CAISO expects it would file a project sponsor agreement with FERC in January 2025.

Jeff Billinton, CAISO director of infrastructure planning, reported that stakeholders were generally supportive of the project, but some were concerned about costs. But Millar noted that the approval timeline allowed for plenty of opportunity for comment throughout 2024.

"Only after the FERC approves the project sponsor agreement do any cost-commitment issues arise; termination provisions go into effect," he said. CAISO would also then begin a quarterly cost review process with LS Power. "So we believe that these gating checkpoints provide the right milestones, the right transparency [and] the right visibility." ■

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Texas Appeals Court Clears Generators of Uri Lawsuits

By Tom Kleckner

Texas generators may escape further litigation for their inability to meet demand during the 2021 winter storm after a state appeals court ruled Dec. 14 that wrongful death, personal injury and property damage cases against the generators have "no basis in law or fact" (*01-23-00097-CV, 01-23-00102-CV, 01-23-00103-CV, 01-23-00392-CV and 01-23-00393-CV*).

The *1st Court of Appeals* in Houston ruled that wholesale power generators in ERCOT's deregulated market are "statutorily precluded by the Legislature from having any direct relationship with retail customers" and "can have no legal relationship with retail customers as a matter of law."

"Texas does not currently recognize a legal duty owed by wholesale power generators to retail customers to provide continuous electricity to the electric grid, and ultimately to the retail customers, under the allegations pleaded here by the retail customers," the court said.

According to *Texas Lawbook*, the decision will lead to the dismissal of Luminant, NRG, Exelon, Sempra Energy Resources and other generators from the hundreds of lawsuits filed in the wake of Winter Storm Uri.

The storm brought sub-freezing temperatures and precipitation to much of the state that shut down thermal and nonthermal power plants alike. The state says almost 250 people died during the resulting dayslong outages, although it's thought that number is much higher.

Hundreds of retail customers sued hundreds of entities involved in the ERCOT market for damages sustained due to the outages. They alleged negligence and gross negligence for failing to winterize and maintain their equipment, failing to ensure adequate fuel supplies and failing to properly train workers to ensure against the generator outages that occurred.

The lawsuits were consolidated into multidistrict litigation before Harris County District Judge Sylvia Matthews, who dismissed all the allegations except the negligence claims. The judge then selected five bellwether cases as representative of the cases filed.

The generators filed a petition with the appeals court, arguing that Matthews had abused her discretion in not dismissing the negligence charges. The court agreed, saying the charges should have been dismissed because the retail customers' arguments alleged actions "have no basis in law or fact."

The opinion applies to the five bellwether cases. The plaintiffs' legal counsel has said they plan to appeal.

The Texas Supreme Court ruled in June that ERCOT, which operates 90% of the state's grid, enjoys sovereign immunity and cannot be sued over the blackout. (See *ERCOT Sovereign Immunity Affirmed by Texas Supreme Court*.)

The state high court will hear arguments next year from Luminant (*23-0231*) and RWE Renewables (*23-0555*) over the Public Utility Commission's emergency pricing order following the winter storm. The PUC directed prices be maintained at the $9,000/MWh cap to incent more generation to come online and end load shed. ■

A Texas appeals court has rejected claims of negligence by generation plants during the 2021 winter storm. | *Entergy*

ERCOT News

McAdams Honored During Last Texas PUC Meeting

By Tom Kleckner

Texas Public Utility Commissioner Will McAdams made good on his intention to resign from the commission by the end of the year, sitting through his last open meeting Dec. 14 as a member of the regulatory body.

McAdams, who told *RTO Insider* last month of his plans to resign before next year, wiped away tears as he thanked staff, his fellow commissioners and his family for what he called "one of the highest and true honors of my life." (See *McAdams Says He Will Resign from Texas PUC*.)

"As I told the reporters, there comes a point for everybody when they evaluate their work-life balance and identify a need to take a step back; they need to heed that feeling," he said. "That point has come for me. As I said then, this is a time for new blood to come in and continue to work on the momentum that we have created and started here."

McAdams is the longest-tenured commissioner, having been appointed to the PUC in March 2021 shortly after the disastrous winter storm that nearly collapsed the ERCOT grid. His term was to expire Sept. 1, 2025.

The previous commission having resigned or been asked to step down, McAdams and the other commissioners who eventually joined him have spent that time implementing new rules after two legislative sessions, evaluating and redesigning the ERCOT market, and restoring staff confidence.

"As we have long said, this is not an easy assignment. The current commission was composed under extreme circumstances," he said. "It seems to me that 2021 was a defined demarcation line and time. Especially for those working at this agency, there is now a pre-2021 history for the PUC and a post-2021 history that has yet to be made, and it's never going back."

Cake presented to McAdams by PUC staff during reception in his honor | *Texas Public Utility Commission*

"I feel privileged to have been here during that transition. The function that this agency serves is essential, and nothing's going to change that," McAdams added. "Our role as regulators is to instill and maintain confidence in the rule of law, the spirit of fair play and competitive neutrality in an environment with large and powerful corporate forces, all to ensure the best possible outcomes for Texas consumers."

"Today is a bittersweet day," interim PUC Chair Kathleen Jackson said as she opened the meeting. "On behalf of all Texans, I want to thank you for your tireless efforts since being appointed as the first new commissioner after Winter Storm Uri. You stepped up to the challenge with a desire to make a difference. ... You've been an invaluable resource to me, the PUC and ... the state of Texas."

Commission staff recalled the day McAdams first appeared in the office. He was an industry outsider but had a strong working knowledge of the market through his policy work as a legislative staffer.

"My first thought when we were told Will McAdams was headed this way was, 'Thank goodness! Someone who speaks electricity,'" said Connie Corona, deputy to Executive Director Thomas Gleeson. "We were well acquainted with you and your expertise and dedication to good public policy from working with you over the years. Thomas and I were sitting in a very lonely hallway on that day."

"You strolled in and basically said, 'We've got this,' and never looked back," she added.

"On March 15, 2021, Connie and I found ourselves with no one at the dais," Gleeson said. "Being first is always difficult, and I've told you privately how much I appreciate that you were willing to go first and what that meant and how that helped with the 2021 [legislative] session. You really turned it around for us. Thank you for going first."

"We all came in here and had a very challenging mission from Day 1: implementing all the legislation that got passed after Winter Storm Uri; engaging on several rounds of market reform discussions," Commissioner Lori Cobos said. "The amount of work that we've accomplished over the last two years has been [immeasurable]. For that, I thank you for all of your leadership, your service, your support and your friendship."

Will McAdams (center) stands with his wife, and fellow commissioners (left to right) Jimmy Glotfelty, Kathleen Jackson and Lori Cobos. | *Texas Public Utility Commission*

McAdams took a leadership role on *ERCOT's task force* evaluating how aggregated distributed energy resources (ADERs) could participate in the wholesale market and their ability to serve as virtual power plants. He also threw himself headfirst into his SPP responsibilities, chairing a *leadership team* addressing the RTO's resource adequacy issues.

"We had a great opportunity to work together on the ADER task force. That was your leadership and my nudging you in one direction, but you let your team lead that, and Texas is going to be much better for it," Commissioner Jimmy Glotfelty said. "Having been in this business for 30 years, to watch the first few months and you grow your understanding of the market. Gosh, it was just great to see you stand up and be your own person and lead and lead and lead, and I know that's to your core."

The commission is now left with three members, two short of full capacity following Peter Lake's resignation as chair in June. Gov. Greg Abbott's press office did not respond to a question on when future PUC appointments might be made.

McAdams will chair the SPP Resource and Energy Adequacy Leadership Team's final meeting of the year Dec. 18 before turning the position over to his likely successor, Kristie Fiegen, who chairs the South Dakota Public Utilities Commission.

Cobos will replace McAdams as Texas' delegate on SPP's Regional State Committee, with Glotfelty replacing Cobos on the Organization of MISO States. ■

ERCOT News

LP&L Moves Remaining Customers into ERCOT System

Retail Competition Will Replace 'Alley-by-alley' Experience in Lubbock

By Tom Kleckner

ERCOT said Dec. 12 it has completed the *largest single transfer of customers* in its history with the final migration of Lubbock Power & Light (LP&L) customers from SPP.

The city of Lubbock joins San Antonio and Austin as municipalities in ERCOT's competitive retail market. The more than 107,000 LP&L customers will be able to begin choosing their power providers in January.

That is a big change from the West Texas city's previous experience with "alley-by-alley" competition that existed until 2010, said Matt Rose, LP&L's public affairs and government relations manager, this year.

During the Gulf Coast Power Association's fall conference in October, Rose recalled when LP&L and Xcel Energy subsidiary Southwestern Public Service (SPS) both had distribution facilities on either side of alleys.

"Depending on who you wanted to go with, you chose and then you got hooked up on one side in the alley or the other," he said.

In 2010, LP&L bought SPS' infrastructure and LP&L became more of a traditional municipality, serving all the customers in its footprint as a vertically integrated utility. Faced with spending about $700 million to build more generation, LP&L reached a decision point in 2014.

"We said, 'We have a choice. We can build a power plant, stay in the Southwest Power Pool and operate as we have the past 100 years. Or we can take a look outside Lubbock.' We could see that these transmission lines for ERCOT are really one county north, east and south of us," Rose said, alluding to ERCOT's transmission system.

LP&L said in 2015 it intended to transfer its load to ERCOT, beginning a process that culminated with the Public Utility Commission's approval three years later. The process involved paying SPS $77.5 million for early termination of a power contract that would have cost the utility more than $17 million a year through 2044. (See *Texas PUC OKs Sempra-Oncor Deal, LP&L Transfer*.)

The utility successfully transitioned 70% of its load to ERCOT in 2021. The remaining 30% was moved into ERCOT in what LP&L said was a "seamless migration," beginning early Dec. 9 and concluding midmorning Dec. 11.

Now, rather than choosing a provider on one side of the alley or the other, LP&L consumers can select from more than 85 retail providers during a six-week "shopping" window that begins Jan. 5. The utility then will begin migrating the customers to their chosen providers in March and become a transmission and distribution entity.

"This has been an interesting and a fun experience, but Lubbock was able to do this because Lubbock is uniquely situated," Rose said. "We were ending all business in the Southwest Power Pool in order to move to ERCOT, and that allowed us the liberty to go pursue this." ■

Lubbock's utility will be able to offer its customers a choice of electricity providers in March. | *City of Lubbock*

ERCOT News

Texas Public Utility Commission Briefs

ERCOT Shares More Details on Sept. 6 Level 2 EEA

ERCOT staff last week shared additional details with Texas regulators on the Sept. 6 frequency drop that lead to the grid operator entering emergency operations for the first time since the disastrous 2021 winter storm.

Dan Woodfin, ERCOT's vice president of system operations, told the Public Utility Commission during its open meeting Dec. 14 that more than 500 MW of the system's physical responsive capability (PRC) was incorrect and/or unavailable at a time when PRC was dropping to 2,100 MW (*54444*).

Woodfin said staff issued a request for information to entities contributing to PRC because "we had reason to believe" the information it was receiving from participants to calculate the reserves "was probably too high." He said when frequency was at its lowest, calculated PRC was about 564 MW higher than what it should have been.

Thermal generators were reporting about 200 MW of capacity they could reach, an incorrect reading based on ambient air temperatures, Woodfin said.

"There's always a little bit of error there," he said.

Woodfin said another 200 MW were unavailable from curtailed wind resources that were unable to respond to frequency because their automatic controls didn't work properly. Another 158 MW were unavailable from energy storage resources (ESRs) that had depleted their state of charge (SOC) and couldn't regain their SOC quickly enough.

The frequency drop led to a dip in operating reserves below the 2,300-MW threshold, forcing ERCOT to issue a Level 2 energy emergency alert to maintain critical system frequency. The grid operator limited transmission from South Texas, trapping available wind generation along the Gulf Coast. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

Demand peaked at 82.7 GW on Sept. 6, setting a new high for September. The ERCOT grid was without 10.5 GW of unplanned outages at PRC's lowest point, below the summer's typical daily outages of about 12 GW, Woodfin said.

"I think these are things that are going to be more normal than not, at least until the transmission line from the south gets completed and some of the reliability issues get resolved. Long term. I hope this was a lesson," commissioner Jimmy Glotfelty said.

The PUC has approved a pair of transmission projects designed to increase capacity between South Texas and the rest of the grid.

SOC Discussion Deferred Again

The commission granted ERCOT's request to defer further discussion of a proposed rule change that sets a one-hour SOC for ESRs participating in two ancillary services and that Glotfelty has called "totally discriminatory" to the resources (*54445*).

The grid operator told PUC staff that the delay would give it a chance to better prepare its materials and give the commission and market participants to review and comment on its presentation materials. ERCOT is committed to filing a detailed presentation no later than Jan. 4.

The nodal protocol revision request (*NPRR1186*) has drawn opposition from storage developers during the stakeholder process. The PUC declined to approve the change during its last meeting and will take it up during its next open meeting Jan. 18. (See *Texas Public Utility Commission Briefs: Nov. 30, 2023*.)

Glotfelty accepted the delay, questioning whether ERCOT staff's time couldn't be better spent on other work.

"We want to make sure that we get all the information that ERCOT can provide before we take action on it," Commissioner Lori Cobos said. "I really do hope that we get some good information from ERCOT to help us better understand the issues they're seeing from their perspective."

The PUC did approve two consulting firms' *work plan* for a value-of-lost-load survey and study to determine the estimated value of reliability in the ERCOT region (*55837*).

The Brattle Group and PlanBeyond plan to survey retail customers using contact information provided by the grid operator in competitive areas and historical kilowatt-hour energy usage in competitive areas. The firms will have to depend on ERCOT's relationships with non-opt-in entities, such as municipalities and cooperatives, and partner with them in their service territories to gather the same information.

The firms plan to complete the survey and deliver its results to the commission by the end of June. They say the study will be "fundamental" in supporting the PUC's market design initiatives, including the development of a reliability standard.

ERCOT's Dan Woodfin explains the Sept. 6 energy emergency alert. | *Admin Monitor*

Permian Basin Reliability Plan

Cobos and commission staff hosted a public workshop for oil and gas representatives, transmission and distribution utilities, and ERCOT staff in Midland on Dec. 12 to discuss reliability and electrification needs in the petroleum-rich Permian Basin (*55718*).

"Texas is the No. 1 energy-producing state in the United States, Texas energy powers the world, and the Permian Basin is a critically important part of this success," Cobos said.

Legislation passed earlier this year requires ERCOT to work with transmission service providers to develop a reliability plan for the Permian Basin region. The plan must address the region's transmission needs, additional generation to meet the energy industry's demand and streamlining interconnection processes.

The plan is due to the PUC in July for stakeholder feedback. The commission then will consider the plan for its approval.

345-kV Project Approved

The PUC approved *revised certificates of convenience and necessity* for a 345-kV double circuit transmission line in West Texas needed to address reliability issues driven by rapid oil and gas load growth and to improve import capability into the Delaware Basin.

The joint project between Lower Colorado River Authority Transmission Services Corp. and Wind Energy Transmission Texas involves 68 miles of new circuits and substation upgrades. It's estimated to cost $370 million and be in service in 2026, when the region's load will exceed 4,000 MW (*55120*). ■

— Tom Kleckner

ERCOT News

Texas RE: Winterization Activities in 'Good Shape'

By Tom Kleckner

The Texas Reliability Entity's chief engineer, Mark Henry, told the organization's Board of Directors last week that ERCOT generators' winterization efforts are in "pretty good shape" in preparing for a NERC cold-weather standard.

"We found that people who did have issues in our region during [the December 2022] winter storm generally are following through with the actions that are expected here and of course with the things that are part of the state rules now," Henry said during the board's Dec. 13 meeting, promising Texas RE will follow up with some of the entities to ensure "we're not missing something."

NERC gathered the data last year from balancing authorities, transmission operators, and 1,160 generation owners and operators. They were asked to identify specific actions determined to be essential to the bulk power system's reliability and the status of those actions.

Henry said 245 ERCOT generators were surveyed, with 82% saying they didn't experience a cold-weather reliability event during last winter and 86% saying they have completed or partially completed essential actions identified by NERC.

ERCOT generation owners have calculated the extreme cold weather temperature (ECWT) for their facilities, with 96% saying they can operate at that temperature, Henry said. The ECWT is higher than 10 degrees Fahrenheit, which is higher than the February 2021 winter storm's extreme conditions.

Texas RE staff has shared some of the information gathered with ERCOT that could boost the ISO's weatherization-inspection program.

"We're going to stay plugged into what they're doing and let the folks in the other NERC regions know how we're prepared down here in Texas," Henry said.

The cold-weather standard (*EOP-012-2*, extreme cold weather preparedness and operations) is hung up in NERC's approval process, having failed two rounds of voting. NERC's Board of Trustees have said they may have to take matters into its own hands if the standard fails another vote. (See *NERC Board May Force Action on Cold Weather Standard*.)

Corbett to Chair Board

The board approved the nominations of Jeff Corbett and Suzanne Spaulding as its chair and vice chair. They will replace Milton Lee and Crystal Ashby in 2024.

Corbett was a senior executive with Duke Energy after 30 years at Dominion Virginia Power and Progress Energy. Spaulding, who recently was elected by Texas RE's membership to another three-year term as an independent director, has cybersecurity experience at the federal level and also spent six years at the CIA. She currently is senior adviser for homeland security at the Center for Strategic and International Studies (CSIS).

The Members Representative Committee selected its 2024-25 representation in November. It will vote on its leadership in January.

The MRC members are:

- Chad Thompson, ERCOT;
- Daniela Hammons, CenterPoint Energy;
- Lance Spross, Oncor;
- Frank Owens, Rayburn Country Electric Cooperative;
- Shari Heino, Brazos Electric Power Cooperative;
- Curt Brockmann, CPS Energy;
- Brock Carter, Austin Energy;
- David Hodges, RWE Renewables;
- Kristina Marriott, Miller Bros. Solar;
- Jeremy Carpenter, Tenaska Power Services; and
- Venona Greaff, Occidental Power Services.

Brockmann, Greaff, Hammons and Heino are incumbents.

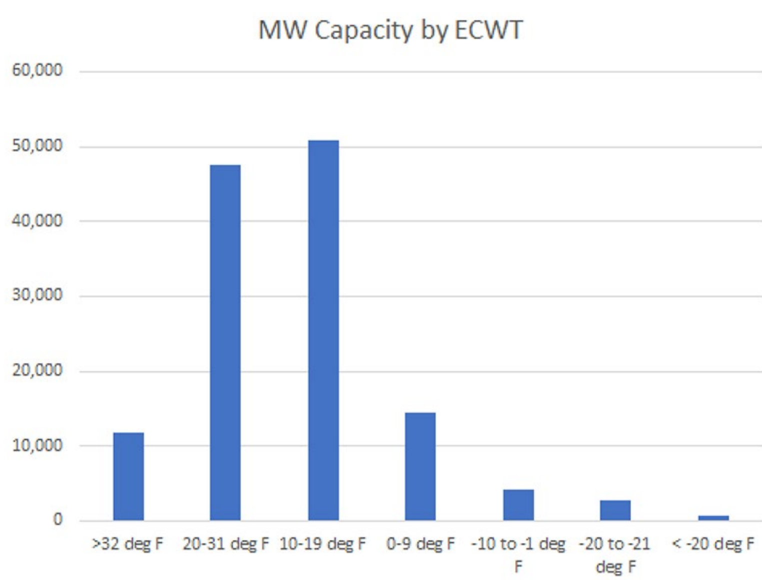
Texas RE Wins Workplace Award

Texas RE CEO Jim Albright celebrated the organization's inclusion among the *top workplaces in the greater Austin area*, as nominated by employees and recognized by the Austin American-Statesman. The reliability entity placed 14th among organizations with between 50 and 149 employees.

"This is a great achievement. Over the past three years, we've worked together to enhance our workplace culture," Albright said during the annual membership meeting. "We believe this award … provides us some evidence that we're going in the right direction. We were just 14 out of 66, so we still have room for improvement."

Staff also reported Texas RE had a net gain of 17 members during the year to push its membership to 125. Generation accounts for most of the total with 89 members, followed by municipal utilities (11) and transmission and distribution providers (10).

As of Nov. 1, Texas RE had 335 registered entities, a gain of 32 from a year ago. ■



Almost all ERCOT generators say they can meet extreme weather temperatures below 20 degrees. | *Texas Reliability Entity*

ISO-NE News

Analysis Group Recommends Prompt, Seasonal Capacity Market for ISO-NE

By Jon Lamson

WESTBOROUGH, Mass. — ISO-NE should move to a prompt and seasonal capacity market to better accommodate the evolving mix of resources and reliability risks in the region, Analysis Group told ISO-NE stakeholders at the NEPOOL Markets Committee (MC) meeting Dec. 13. The consulting firm recommended the RTO make the move for the 2028-29 Capacity Commitment Period (CCP).

In November, NEPOOL voted to delay Forward Capacity Auction (FCA) 19 — which corresponds to the 2028-29 CCP — by one year to complete resource capacity accreditation (RCA) changes and consider moving to a prompt and/or seasonal capacity market. (See *NEPOOL Votes to Delay FCA 19*.)

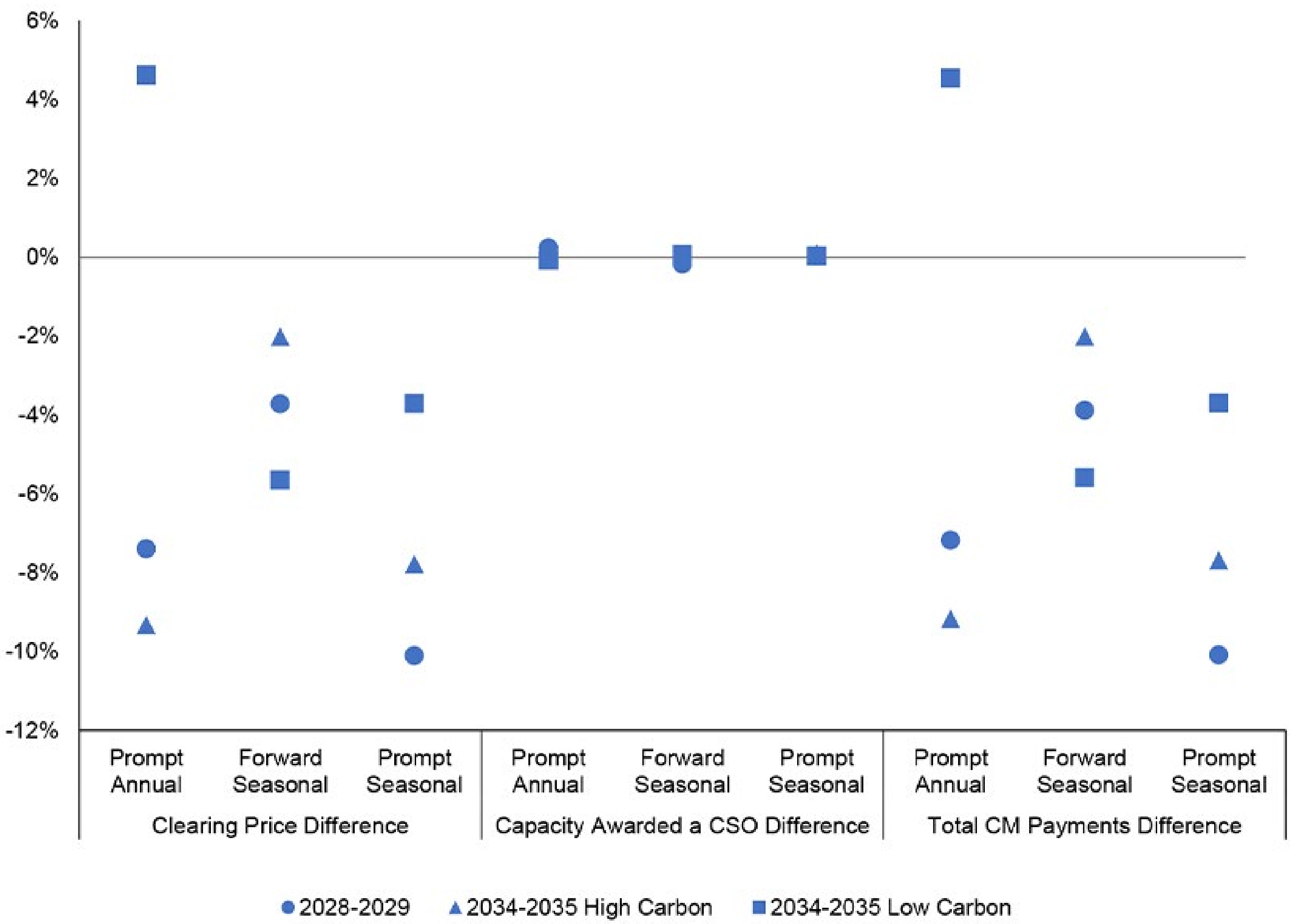
While FCAs currently are held more than three years prior to the CCP, a prompt capacity auction would be held just months before the CCP. Changing the auction to a seasonal format would break up the yearlong CCP into distinct seasons.

ISO-NE has commissioned Analysis Group to study and make recommendations on the potential move to a prompt and seasonal auction format. The study has a condensed timeline to leave time for stakeholders to contemplate the impacts of the changes. (See *Analysis Group Details Methodology of ISO-NE Capacity Market Study*.) The firm released its *draft results* prior to the December MC meeting.

Moving to a prompt and seasonal capacity market would "allow the region's capacity market to adapt to and support the transition toward a grid of the future for the region," Todd Schatzki of Analysis Group told stakeholders. He added the changes would "improve resource adequacy outcomes in both economic and reliability terms."

One of the key benefits of holding the auction closer to the CCP would be more detailed information on both supply and demand, Schatzki said. It also would entail less deliverability risk for new resources coming into the capacity market, since all resources bidding into a prompt capacity market would need to be ready to provide capacity.

While the forward capacity market initially was designed to align with the development timelines of new power plants, the current timelines for new resources vary significantly between resource types, Schatzki said. While



Cost and capacity effects of a prompt and seasonal capacity market | *Analysis Group*

ISO-NE News

battery storage can arrive as soon as nine months, gas plants and offshore wind can take up to 48 months, he added.

A prompt auction could provide a "more neutral competitive platform for new investment," Schatzki said.

Regarding a seasonal format, "a seasonal market can account for differences in the value of capacity in reducing reliability risks across seasons," the draft report found. "By accounting for these differences when procuring capacity in each season, so that more capacity is procured in seasons with greater reliability risks, it can lower the costs and improve resource adequacy."

Analysis Group performed a limited quantitative assessment of the financial impacts of the capacity market changes, which found that prompt and seasonal changes would reduce costs in most cases, with the cost benefits ranging from 2% to 10%.

The firm also found that a prompt and seasonal market likely would provide more incentives for firm natural gas fuel arrangements, because these fuel commitments often are made in the summer and fall prior to the winter.

"Compared to a prompt market, making commitments three-plus years in advance would be expected to raise costs of these commitments and reduce the scope of firm fuel arrangements," Schatzki said, noting that the under-development RCA updates also could increase incentives for firm fuel commitments.

One basic drawback of a prompt and seasonal market would be the time and effort required to make such major changes, and administering seasonal auctions would mean more work for ISO-NE, Schatzki said.

The draft report also noted that no other regions that heavily rely on capacity markets to meet resource adequacy needs have a prompt and seasonal capacity market.

"However, other regions have, or are in the process of assessing or implementing, prompt and seasonal market designs, and the technical risks of developing a prompt-seasonal market appear manageable," the report concluded.

Schatzki added that some aspects of the market may need to be reconsidered if the RTO elects to move to a prompt and seasonal auction to avoid unintended consequences. These include the resource qualification and retirement processes, supply offer components and market mitigation.

Looking forward, Analysis Group will present the final report at the January MC meeting, and ISO-NE is planning to make a recommendation on the capacity market changes at the February MC meeting.

RCA Updates

The MC also discussed updates to the accreditation methodology for oil and gas resources.

In the new RCA format, resources will be compared to a theoretical perfect capacity resource that lacks operating constraints. This method is intended to create a neutral point of comparison for the reliability and resource adequacy attributes of all capacity resources on the system.

In ISO-NE's proposal, gas resources' firm fuel arrangements will affect their accreditation value, while oil resources' accreditation value will be affected by their storage capabilities.

Oil capacity for both oil and dual-fuel resources will be judged on an individual basis, while gas capacity will be estimated at a fleet level to account for the region's seasonal gas constraints, ISO-NE said.

"An aggregate hourly profile will be used in the winter period to represent the hourly gas fleet generation using the daily gas available to the fleet subject to the gas system limitation," ISO-NE said.

The aggregated gas fleet capacity value then will be allocated to individual resources, which could improve their accreditation through firm arrangements including firm gas supply and pipeline contracts, as well as added dual-fuel capabilities or LNG vaporization capabilities.

Additional firm gas contracts that reduce the total amount of gas available to the rest of the fleet would lower the accreditation values of non-contracted gas generators, ISO-NE noted. ■

ISO-NE News

Phillips Details Reliability Concerns at NEPOOL Meeting

By Jon Lamson

BOSTON — Hoping for a mild winter is not a sustainable plan for reliability, FERC Chairman Willie Phillips said at the Dec. 7 NEPOOL Participants Committee meeting. He said he's concerned premature retirements of legacy generators and infrastructure will threaten the reliability of the New England grid.

Phillips expanded upon his concerns, initially outlined in a letter co-signed with NERC CEO Jim Robb regarding the potential loss of the Everett LNG import facility in Massachusetts. (See *FERC, NERC Leaders Voice Concern About Loss of Everett Marine Terminal*.)

While ISO-NE's winter reliability studies indicate Everett doesn't significantly improve the reliability of the grid during extreme weather conditions, Phillips said the RTO should "continue to work and think about the assumptions and the methodology that are used in that study to make sure that we get this right." (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

Asked whether electric ratepayers should bear the costs of keeping Everett open, Phillips responded "I don't have an opinion — and I'm not here to give one — on who should pay," adding that it's not FERC's jurisdiction to make the decision.

The chairman also connected the need to maintain grid reliability to the region's decarbonization goals. While applauding the states' clean energy ambitions, Phillips said the region must keep reliability "top of mind" as it pursues its clean energy goals.

"If we get this wrong, it is the transition that will be blamed," Phillips said.

Phillips also emphasized the need to consider environmental justice and existing energy infrastructure burdens when planning and siting new infrastructure.

"I grew up in an environmental justice community," Phillips said. "I know what it smells like."

He said he hopes to issue an "outward-facing guidance document" detailing expectations regarding engagement with environmental justice communities.

Prior to Phillips' speech, a group of climate activists associated with the organization No Coal No Gas pressed NEPOOL officers to let them sit in on the meeting, which the NEPOOL officers allowed.

While New England ratepayers can join the organization for a $500 membership fee, several members of ISO-NE's Consumer Liaison Group Coordinating Committee (CLGCC) who lack institutional support are not NEPOOL members.

In December 2022, No Coal No Gas successfully elected a slate of candidates to the CLGCC which included several members of the climate group. (See *Climate Activists Take Over Small Piece of ISO-NE*.) The group now is pushing for elected CLGCC members to be given governance-only seats at NEPOOL.

Everett LNG facility | *Constellation Energy*

Operations Report

The total energy market value in November was up by about 45% compared to October but was more than 40% less than the total value from November of 2022, ISO-NE COO Vamsi Chadalavada *told the PC*. The monthly increase relative to October was because of higher natural gas prices, Chadalavada said.

The estimated carbon emissions from November were down relative to both October of this year and November of 2022, Chadalavada added.

Regarding this winter, Chadalavada said ISO-NE's capacity analyses based on the forecasted load indicate "a surplus even after accounting for generation at risk due to gas supply." (See *ISO-NE Says Region Has Enough Resources for Upcoming Winter*.)

Chadalavada added that the region's weather can change quickly and noted that "extended periods of cold weather may rapidly deplete stored fuel inventories and capacity outlook will be adjusted accordingly."

IMM Report

David Naughton, executive director of ISO-NE's Internal Market Monitor (IMM), presented to the PC on the IMM's 2022 *Annual Markets Report*.

The report notes that weather-normalized load has increased slightly over the past two years following years of decline due to energy efficiency efforts.

"The trend of decreasing load may have reached an inflection point," the report states, adding that "while it is difficult to attribute this directly to any particular driver, this change is consistent with the ISO forecast that average load will increase each year with the continued adoption of electricity-fueled transportation and electric heating."

Naughton also noted total energy costs in 2022 nearly doubled compared to 2021 and were the highest since 2008.

In other NEPOOL business, the PC *approved* the 2024 NEPOOL expense budget and elected a slate of officers to run the PC in 2024, which will by chaired by Sarah Bresolin of ENGIE North America. The PC also voted to support changes to its Financial Assurance Policy regarding the calculation of Forward Capacity Market delivery financial assurance. ■

ISO-NE News

Storm Cuts Power to 750,000-plus in New England

Rain, Wind Bring Cause Extensive Tree, Wire Damage

By John Cropley

A coastal storm packing high winds and heavy rains left hundreds of thousands of customers across the Northeast without power Dec. 18.

Electric utilities prepared in advance, bringing in reinforcements and pre-staging them as the unnamed storm moved north with rain and storm surges that wreaked havoc in parts of the Southeast on Dec. 17.

But damage on Monday was so widespread, particularly in New England, that power outages proved slow to fix.

By midafternoon, *poweroutage.us was showing* 750,000 customers without electricity in five of the New England states. According to utility reports, well over 100,000 others lost power but had regained it by that point.

The sixth state — Vermont, so badly pummeled by flooding earlier this year — held up much better, with only 1,300 outages at 2 p.m. and 1,900 by 6 p.m.

The weather system moved north into Quebec and the Maritime Provinces, with rain ending in southern New England by late afternoon. The National Weather Prediction Center warned of moderate risk of *flash flooding* into Tuesday in northeast New England.

Maine was hardest hit, with 372,000 customers without power as of early Monday afternoon, climbing to 430,000 by early evening.

Versant Power's outage map showed outages spread across the eastern side of the state. At 3:20 p.m. Monday, it posted on X that it was temporarily standing down its restoration efforts:

"Wind gusts up to 70 mph will continue through the afternoon into the evening. For the safety of our crews, they will not be going up in buckets to perform work and are responding to emergency situations only at this time until further notice."

Central Maine Power's outage map showed scores of outages concentrated in the southeast portion of the state. Around noon, the utility posted on X:

"Our nearly 400 line and 200 tree crews are working with local agencies to respond to emergencies. With several more hours of strong winds expected, we anticipate a multi-day restoration effort is ahead."

An Eversource crew responds to a downed tree and broken pole in Meriden, Conn., during Monday's storm. | *Eversource*

A day earlier, Central Maine Power had warned about the possibility of heavy tree damage as the storm moved toward New England: "Given the already water-saturated soil from previous storms, with more rainfall expected, trees may be more vulnerable to the strong winds associated with this storm," it said Sunday.

ISO-NE told *RTO Insider* that it was monitoring the situation, but the storm had not affected the regional grid as of midafternoon Monday: "While there are outages on the distribution side of the system because of the storm, the bulk power system in New England is currently operating under normal conditions. ISO New England is constantly monitoring the system, and our experienced system operators are trained to handle various weather-related outages that may arise."

Massachusetts was a distant second in the poweroutage.us tally — 260,000 customers without power at midafternoon, dropping to 239,000 by evening.

Eversource provided the public a stream of updates in Connecticut, Massachusetts and New Hampshire that described a continuing give-and-take with a storm — power restored to 61,000 customers in Massachusetts alone, but 93,000 still without power as of midday, and more outages happening as more trees toppled.

The utility used newer technology to avoid sending crews up in bucket trucks where possible: Its 38-MWh battery energy storage system on outer Cape Cod kept the lights on for 5,600 customers and smart switch technology turned the power back on for thousands more.

Steve Sullivan, president of Eversource Connecticut, gave an update broadcast live on Facebook toward sunset Monday. He said that the utility had approximately 1,200 crews on duty, but progress was slow.

"This is a multiday restoration. It's really too early to pin down when we will finish because we have well over 2,000 outage events and we want to make sure that we get eyes on every one of them. And really, the winds just died down within the last few hours."

Sullivan said Eversource is triaging its response, clearing downed trees from roads first in partnership with municipalities, for whom that is a top priority. Next, it will restore power to critical-priority facilities, then schools. Remaining outages will be prioritized by size, with the largest being addressed first.

Rhode Island Energy said it had about 23,000 customers without power late Monday afternoon and anticipated restoring the vast majority by Tuesday evening. It brought in hundreds of line and forestry workers before the storm and had more than 1,600 people in total working on recovery Monday.

"This was a very severe storm that ripped through the region, and with the ground already saturated and trees weakened from last weekend's storm, we expected we would see significant outages today," President Dave Bonenberger said in a news release. "And while we've been able to get many customers restored, we've also seen some challenges in getting our buckets up in the air with these ongoing winds."

Looking south along the Atlantic coast, other states were in far better shape than New England.

New Jersey, New York and Pennsylvania respectively had 18,000, 14,000 and 7,000 utility customers in the dark at 5:30 p.m., poweroutage.us indicated. Delaware, Maryland, Virginia and the Carolinas had fewer than 5,000 combined. ■

MISO News

Former Employee Details Failures at Entergy's Grand Gulf

Worker Claims He was Fired for Whistleblowing; Company Says He Failed Drug Test

By Amanda Durish Cook

A former employee of Entergy's Grand Gulf Nuclear Station testified last week that he witnessed mismanagement by plant supervisors and was fired for refusing to revise audits documenting problems.

Jairus Greene testified Dec. 12 at the request of the Louisiana Public Service Commission, which is seeking millions in refunds from Entergy over alleged mismanagement of the 1,443-MW plant (*EL21-56*).

Testifying at the law offices of Stone Pigman Walther Wittmann in New Orleans, Greene said he witnessed poor engineering decisions, frequent reactor trips and scrams — or the sudden shutting down of a nuclear reactor — exemplified by Grand Gulf's unusually low capacity factor. At one point, Greene said he couldn't recall the length of individual outages because trips were commonplace. From 2016 through 2018, Grand Gulf ran at about a 55.5% capacity factor when other nuclear plants in the nation averaged over 92%, according to *data* from the U.S. Energy Information Administration.

Entergy says it has improved the plant's operations, *touting* its 95% capacity factor in 2021. The utility also said Grand Gulf attained the highest rank in the Nuclear Regulatory Commission's performance *matrix* in 2022.

Greene, who has more than 20 years' experience in nuclear capital projects and cybersecurity, worked at Grand Gulf for about three years before he was fired in April 2022.

Greene spoke carefully during his deposition, acknowledging he lacked first-hand knowledge of some of what he reported, which came from other employees.

He said he believed security personnel at the plant worked shifts that were too long and they had no time for bathroom breaks. Employees found human excrement in some areas of the plant, he said.

He said he was aware of Grand Gulf's poor reputation when he was hired. He "was kind of ashamed to admit" he worked in "a place like this," he testified.

Greene said Grand Gulf leadership choose not to conduct engineering hold points — a pause on construction activities until an inspection is passed — as part of a turbine

Grand Gulf Nuclear Station | *Entergy*

controls project in 2020.

Greene said he was concerned that some equipment considered critical digital assets at other reactors he worked at wasn't considered such at Grand Gulf.

He also said there seemed to be numerous maintenance deferrals throughout his employment.

Greene said he took his concerns over pressures to issue more favorable audit findings and a chilled work environment to the Nuclear Regulatory Commission.

Greene said he and other employees would meet informally at a nearby supermarket to discuss their concerns over the plant. Some colleagues left their positions to avoid compromising their integrity, he said.

Greene said shortly after he wrote a memo on security lapses, he found his security clearance revoked. Shortly after, he was fired.

However, Greene said he still believes in nuclear power though some utilities don't operate plants reliably.

In March, Greene filed a federal lawsuit against Entergy in the Southern District of Mississippi alleging he was fired for refusing to falsify safety reports (5:23-cv-00016). He contends he used legally prescribed THC derivatives to treat severe glaucoma and that Entergy used the pretext of a failed drug test to fire him in retaliation. He said he has never used marijuana.

Entergy spokeswoman Mara M. Hartmann declined to comment Monday on Greene's allegations, citing "pending legal matters."

"Entergy is committed to the safe, secure and reliable operation of our plants in compliance with all applicable NRC regulations, including the NRC's fitness-for-duty requirements," she said. "We are proud that our Grand Gulf Nuclear Station has all green, or best possible, performance indicators in the regulatory performance matrix."

Greene's deposition came in a long-running dispute between Entergy and state regulators. Entergy subsidiary System Energy Resources Inc. operates and owns 90% of Grand Gulf and sells the plant's output to Entergy's Arkansas, Louisiana, Mississippi and New Orleans affiliates.

The Louisiana PSC maintains that ratepayers are owed hundreds of millions of dollars because Entergy mishandled plant operations, undertook an expensive and excessive plant expansion, and engaged in improper accounting and tax violations that shifted costs to ratepayers.

FERC has ruled against Entergy on some tax maneuvers and lease payment collections in another proceeding, though the exact amount owed is still up for debate. Louisiana regulators are asking FERC to fine Entergy $1 million a day for refusing to pay the refunds. (See *Latest FERC Order on Grand Gulf Nuclear Plant Ambiguous on Refund Amount*.)

Last month, Louisiana Public Service Commissioner Davante Lewis *told* *The Times-Picayune/The New Orleans Advocate* that it seems "Entergy is playing a legal maneuver that basically tries to bully us and wear down the clock."

In October, the Arkansas Public Service Commission accepted Entergy's $142 million offer to settle its claims, a year after turning down the same offer. Entergy estimates it has already refunded $50 million of that amount to Arkansas, according to an according to a filing with the U.S. Securities and Exchange Commission.

Mississippi settled its claims related to Grand Gulf in 2022, accepting a $300 million refund. (See *Entergy Offers Regulators $588M to End Grand Gulf Complaints*.)

During a third-quarter earnings *call* last month, Entergy CEO Drew Marsh said the deals with Arkansas and Mississippi resolve approximately two-thirds of the financial risks related to lawsuits over Grand Gulf. Marsh also warned that reaching a resolution in the FERC cases could take up to two years.

Grand Gulf, the largest single-unit nuclear plant in the U.S., began commercial operations in 1985. In 2016, the NRC granted the plant a 20-year license extension, allowing it to operate through 2044. ■

MISO News

FERC Rejects MISO Solar Farm Interconnection Agreement, TO Challenges Upgrades Ownership

By Amanda Durish Cook

FERC last week refused a MISO interconnection agreement for a Michigan solar farm while Commissioner Mark Christie used the order to point out what he called a defect in the MISO tariff.

FERC said MISO is free to file another generator interconnection agreement for EDP Renewables' Eagle Creek solar farm in the future (*ER23-2443-001*).

Currently, the parties to the failed GIA are embroiled in a dispute over how to divvy up ownership interests in the interconnection facilities and network upgrades necessary to accommodate the 120-MW solar farm.

Only transmission owner Michigan Public Power Agency (MPPA) executed MISO's GIA. Michigan Electric Transmission Co. (METC), Wolverine Power Supply Cooperative and generation developer Eagle Creek declined to execute the GIA, which would have split ownership 33.33% apiece among METC, MPPA and Wolverine. The three jointly own the Styx-Murphy 345-kV transmission line, which will need to be extended into a new 345-kV station to connect the solar generation. The line is located on METC's transmission system, and METC said it believes it should have sole ownership over the interconnection facilities and upgrades.

FERC ruled that while MPPA and Wolverine also are legitimate transmission owners with rights to the line, MISO's GIA is inapplicable because it was written for multiple transmission facilities while the Styx-Murphy line is a single transmission facility, albeit jointly owned.

When it filed the GIA with FERC, MISO said Eagle Creek couldn't sign the GIA because the final ownership interests of the network upgrade will affect how much it ultimately owes.

Ordinarily, MISO interconnection customers are responsible for all costs associated with network upgrades to accommodate their generation. When the network upgrades are rated 345 kV and above, interconnection customers can receive a 10% reimbursement.

However, METC operates under a circa-2007 grandfathered arrangement where interconnection customers might be eligible to be fully reimbursed when their projects are designated as network resources or have entered capacity contracts with a network customer. Those costs are covered by the load in METC's transmission pricing zone.

FERC provided guidance to MISO when it refiled the GIA. It said Eagle Creek should pay for MPPA's and Wolverine's proposed combined ownership share of 66.66% of costs, with the 10% reimbursement due after commercial operation. Eagle Creek also initially should fund METC's 33.33% ownership share and be eligible for the 100% reimbursement.

| EDP Renewables

Christie wrote *separately* to disagree with METC's exemption to the usual interconnection costs in the MISO tariff. He said while he agreed with the order because it follows the current tariff, interconnection customers should bear the cost of network upgrades necessary for their projects, not load.

"In 2007, the commission likely made a mistake by accepting the carve-out, which on its face appears to be unduly discriminatory and preferential and, most importantly, unfair to consumers, who should not have to pay a developer's interconnection costs," Christie wrote. ■

MISO to Reformulate Parts of Order 2222 Filing with Stakeholder Input

By Amanda Durish Cook

MISO last week promised five months of additional stakeholder discussion on its Order 2222 compliance plan before it attempts a second filing with FERC to take care of the commission's concerns.

In October, FERC ordered MISO to propose an earlier start date than its proposed 2030 date and explore the possibility of allowing DER aggregations across multiple pricing nodes. (See *FERC: MISO's 2030 Finish Date on Order 2222 Compliance not Soon Enough*.)

FERC allowed MISO an extension until May 10 to hold additional discussions with stakeholders before proposing a new Order 2222 effective date and deciding whether it can handle multinodal aggregations. The conversations largely will take place in MISO DER Task Force meetings.

During a Dec. 11 DER Task Force meeting, Managing Assistant General Counsel Michael Kessler said MISO is in the process of evaluating whether multinodal aggregations might be possible within the footprint.

Kessler also said while FERC appeared to agree MISO needs its new market platform in place before it can handle offers from DER aggregations, it must land on a closer go-live date. The RTO plans to reveal a new date and its reasoning behind it to stakeholders at the April meeting of the task force.

"We're going to have a busy run for the next few months," said DER Task Force Chair Zac Callen, who also is an economic analyst with the Illinois Commerce Commission.

MISO's DER Program Manager Paul Kasper said creating bidding parameters under a multinodal aggregation will be "technically intensive." He also said MISO will need coordination with distribution utilities to answer FERC's questions about MISO's proposed reliability reviews for aggregations and coordination protocols between MISO, distribution utilities and aggregators.

MISO originally said it would handle a new go-live date and multinodal aggregations in a filing separate from FERC's other, less-intensive clarifying questions on MISO's compliance plan. However, the grid operator since decided to make a single filing to satisfy the commission's asks. ■

NYISO News

NYCA Surpasses 5,000 MW of Installed BTM Solar

OC Approves Central East Limits, Discusses Order 2023 Compliance Plan

By John Norris

RENSSELAER, N.Y. — New York now has more than 5,000 MW of behind-the-meter (BTM) solar capacity, bringing the state closer to its goal of installing 10,000 MW of distributed solar energy by 2030, NYISO *announced* at the Dec. 14 Operating Committee meeting.

Aaron Markham, NYISO vice president of operations, reported to the OC that an additional 59 MW of BTM solar integrated into the grid since the previous month, raising the total to 5,018 MW. (The New York State Energy Research and Development Authority *reports* a slightly higher 5,037 MW of distributed solar from 211,083 projects through Sept. 30.)

Markham added that in November, NYISO implemented improvements to the BTM solar forecasting system, which allows for forecasting on a 15-minute instead of an hourly basis. "The expectation is this will improve the performance and accuracy of these forecasts," he said.

Markham also noted that November's peak load reached 21,305 MW on Nov. 29. (See "October Operations," *NYISO Braces for the Coming Winter*.) The month's minimum load was recorded Nov. 5 at 12,471 MW.

Central East Limits

The OC *voted* to approve a draft report *presented* by NYISO re-evaluating the impact of a loss of a New England capacity source on Central East voltage limits.

Solar panels on a rooftop in New York City | *Bright Power, Inc.*

The *report* concludes that the recent energization of the Nos. 351 and 352 Edic-Princetown 345-kV lines on the Segment A project allows Central East to support a loss of 1,500 MW, an increase from 1,320 MW.

The Central East interface is a key part of New York's transmission that regulates the flow of electricity from New England to the central parts the state, in particular Mohawk Valley (NYISO Zone E) and the Capital region (NYISO Zone F).

Raj Dontireddy, a manager of operations engineering at NYISO, said that because NYISO operators cannot monitor or control ISO-NE's sources and dispatch, it is crucial for the ISO to manage imported energy without compromising Central East.

Matt Cinadr, a power systems operations specialist with The E Cubed Co., asked whether the interface could handle more than the 1,500-MW limit.

Dontireddy responded that while 1,500 MW is the maximum allowed based on current limits, NYISO operators can permit a higher ISO-NE source if the total capacity of the Central East interface is not fully used. Markham added that analyses suggest this could increase to around 2,000 MW if the interface has room.

Order 2023

Thinh Nguyen, NYISO senior manager of interconnection projects, *informed* the OC that the ISO plans to file its proposed interconnection cluster study process to comply with FERC Order 2023 on April 3, 2024.

Nguyen provided a detailed review of the cluster study, addressing stakeholder questions and concerns, and shared a comprehensive *overview chart* that details the interconnection timeline and requirements developers must meet to proceed through the queue process.

Stakeholders continued to press NYISO on various aspects of the cluster study process, but the nature of their questions suggested an increasing understanding and acceptance of the proposal compared to previous times the cluster study was discussed. (See *NYISO Stakeholders Question Proposed Interconnection Timelines, Deposit Rules*.)

NYISO will continue developing its proposal into the early part of next year and anticipates reviewing specific tariff language soon. ■

NYISO News

NYISO BIC Stakeholders OK Modeling, Market Design

By John Norris

NYISO control room in Rensselaer, N.Y. | *NYISO*

NYISO on Dec. 13 *presented* its market design for dynamic reserves to the Business Issues Committee, which *endorsed* the concepts on the condition that issues including cost allocation and congestion revenues be discussed next year, as the ISO tests the new design.

The ISO's current operating reserve requirements are static, based on the largest single source contingency.

A NYISO *white paper* in December 2021 proposed that the grid operator explore dynamically scheduling reserves, saying it was feasible to set reserve requirements based on the single largest contingency systemwide and using available transmission headroom. The paper said determining reserve requirements based on grid conditions and topology would better align market outcomes with system conditions by, for example, shifting reserve procurements to lower-cost regions as permitted by transmission capacity. (See *NYISO Outlines Timelines for 2023 Projects*.)

The proposed design is composed of five concepts, including use of individual generator shift factors — the ability of a generator to relieve transmission constraints — to meet locational reserve needs, monitoring about 20 key transmission interfaces and considering the day-ahead market (DAM) forecast load.

The ISO's static locational reserve requirements assume the transmission system is fully scheduled.

NYISO's presentation also discussed how various market elements like thunderstorm alerts, scarcity pricing and the correlated loss of multiple generators might be impacted by the reserve market changes.

NYISO plans to prototype the proposed design and finalize tariff language next year, with the expectation that the concepts will be deployed in 2026.

The ISO said elements such as forecast reserve shadow prices and DAM congestion rents will not be included in prototyping but will undergo review with stakeholders next year.

BIC stakeholders commended the ISO's efforts in establishing a dynamic reserve market design. David Clarke, director of wholesale market policy at the Long Island Power Authority, said "this is really good and really innovative work."

Pallas LeeVanSchaick, vice president at the ISO's Market Monitoring Unit, Potomac Economics, similarly praised the ISO's work. "The scheduling and optimization components are truly innovative and are really going to be helpful to the market in terms of ensuring that the market design is adaptable to changing conditions," he said.

LCR Optimizer Market Design

The BIC also *voted* to approve changes to make the locational capacity requirements (LCR) optimizer more transparent and produce more stable results.

The LCR optimizer, implemented in 2019, establishes the least-cost LCRs for several downstate NYISO capacity zones, including New York City and Long Island.

The ISO *proposed* three changes. First, it suggests determining least cost options by adding up the incremental costs of individual units, which it calls the investment cost — or "area under the curve" — as the optimizer's objective function. The ISO currently seeks to minimize total procurement cost, in which every megawatt of capacity is priced like the last megawatt.

The ISO's second recommendation calls for determining net CONE curves without the level of excess (LOE) adder to simplify the optimizer's formulation.

The final recommendation is to develop additional energy and ancillary services revenue modeling test points in the current demand curve reset project. While NYISO acknowledges that this aspect of the optimizer's formulation has not been tested, it committed to providing updates on these testing efforts next year.

Michael Mager, a partner at Couch White, representing *Multiple Intervenors*, a group of large industrial, commercial and institutional energy consumers, asked about the timeline for initial results from the new testing. NYISO staff responded that these results could be expected in February or March.

Assuming the proposed changes improve the LCR optimizer's results, the ISO aims to seek approval from the Management Committee (MC) in mid-2024 and expects these improvements will be used to determine zonal LCRs applicable for the 2025/26 capability year.

Capacity Accreditation Modeling

The BIC *voted* to recommend that the MC approve proposed tariff *revisions presented* by

NYISO News

NYISO, which aim to improve capacity accreditation modeling by more accurately capturing attributes like natural gas constraints and correlated derates, as well as address issues raised by Potomac Economics. (See *NYISO MMU Calls for Improved Shortage Pricing, More Capacity Zones*.)

Resource adequacy analyses indicate that current modeling misrepresents the marginal reliability contributions of some resources and fails to capture metrics not represented in installed reserve margins and LCRs, resulting in inaccurate capacity accreditation factors and capacity accreditation resource class (CARC) calculations for certain resources. (See *NYISO Previews Capacity Accreditation Modeling Work*.)

The revisions seek to align the compensation capacity resources receive with their performance, availability and marginal contribution to reliability needs.

To address gas constraints, the ISO developed a process allowing gas units to make a "fuel characteristic election" on Aug. 1 prior to the start of the next capability year. This is based on the unit's ability to partly or fully meet requirements for entry into a firm fuel CARC. Units seeking to be firm on gas must have a transportation contract covering the megawatts elected, with a contract path from a liquid receipt point to the burner tip during December, January and February.

Units with on-site fuel are required to have enough to operate at max output for 16 hours a day for six days in those same winter months. The first fuel characteristic election must be made by Aug. 1, 2024, and units failing to substantiate their level of firm supply may face a shortfall penalty.

Howard Fromer, representing Bayonne Energy Center, asked about the impact of these revisions on generation using hydrogen as a fuel source. NYISO staff clarified that these new requirements apply to any unit burning on-site fuel or fuel being delivered through a pipeline.

For correlated derates, NYISO proposes addressing issues identified in the MMU's annual State of the Market report by applying ambient water-related deratings to units with once-through water cooling, adjusting for humidity in units with inlet cooling systems like combined and simple cycle combustion turbines, and sunsetting the capacity-limited resource program, as these emergency capacity resources are rarely committed.

NYISO will finalize the approved tariff language with the Installed Capacity Working Group and continue discussions around correlated derates. The expectation is to present these revisions to the MC in the first quarter of next year for final approval before filing them with FERC.

Transmission Congestion Contracts

The BIC also *voted* to approve *revisions* to the transmission congestion contracts (TCC) manual *presented* by NYISO that incorporate updated technical bulletins addressing modeling assumptions for certain phase angle regulators (PARs).

The TCC manual was last updated in October 2021.

The revisions include updating the modeling descriptions for the "Internal Con Edison PARs" to include the Vinegar Hill PARs (Technical Bulletins Nos. *254* and *255*) and revising the modeling assumptions for the "East Garden City PARs" and "Hurley Avenue PARs" from fixed schedules to schedules optimized by the optimal power flow (Technical Bulletins Nos. *257* and *258*).

November Market Operations

NYISO Senior Vice President Rana Mukerji *presented* the November market operations *report*, saying a "slight uptick" in gas prices slightly increased locational-based marginal price, from $28.10/MWh in October to $34.90/MWh in November. The natural gas index price at Transco Z6 NY was $2.20/MMBtu in November, up from $1.30/MMBtu in October.

Year-to-date average monthly energy prices, however, were 55% lower than the previous year, dropping from $89.97/MWh to $39.32/MWh. This decrease was driven by the continued decline in gas prices throughout the year, with natural gas prices down 54.3% year-over-year at Transco Z6 NY. ■

NYISO Stakeholders Balk at Proposed Day-Ahead Market for Demand Resources

ISO Staff Rejects Expanded SCR Program

By John Norris

NYISO stakeholders continued their criticism of the ISO's effort to improve its demand response programs, saying its recent "issue discovery" report inadequately addressed their concerns and that its proposal to allow demand-side resources (DSRs) to participate in the day-ahead market is hollow.

During the Dec. 6 Installed Capacity/Market Issues Working Group (ICAP/MIWG) meeting, NYISO *presented* findings from its Engaging the Demand Side (EtDS) *report*, a response to stakeholders' request that the ISO investigate whether rules could be improved to reflect DSR's "evolved … capabilities while keeping participation options for these resources simple."

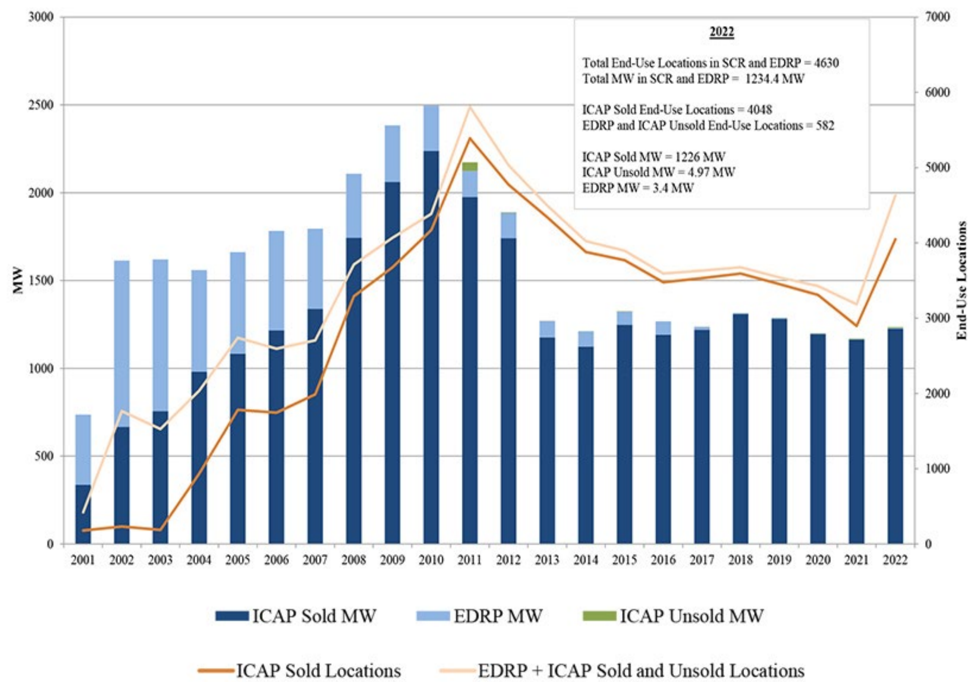
The report recommended investigating a day-ahead-only addition to the DER participation model that it said could increase participation opportunities for DSRs that can operate for longer than the four hours required by the special case resource (SCR) program but cannot participate in the dispatchable DER model, which requires daily bidding and scheduling in the energy market. The report rejected requests to expand the SCR model.

Stakeholders representing demand response providers expressed reservations about the feasibility and cost implications of the proposals, repeating concerns expressed at previous meetings. (See *Providers See 'Mixed Signals' on Demand Response in NYISO*.)

"I am very disappointed in this report and the outcome of this yearlong process of analysis and engagement with the stakeholders," said Amanda De Vito Trinsey, a partner at Couch White, representing the City of New York and large industrial, commercial and institutional energy consumers.

Jay Brew, managing director of Stone Mattheis Xenopoulos & Brew, who represents Nucor Steel Auburn, said he felt NYISO did not appreciate the risks their recommendations could pose to SCRs. "I'm generally disappointed with the level of effort here," he said. "It would seem to me you'd want to be enhancing demand response as much as possible, particularly peak load response, as opposed to seeing the SCR program wither and die."

SCRs are DSRs capable of being interrupted or curtailed by the ISO for at least four consecutive hours each day, and they act as installed capacity suppliers.



Historical enrollment of end-use locations and MW in NYISO reliablity programs | *NYISO*

A DER can be a DSR, a generator or storage resource of 20 MW or less, or a facility of up to 20 MW composed of two or more technology types behind a single point of interconnection.

The report recommends exploring market rules that would enable SCRs to participate in the day-ahead market and allowing them to submit bids or receive schedules without re-evaluation in the real-time market. These DSRs could be able to register with energy durations of two, four, six or eight hours.

The ISO said it hasn't decided whether day-ahead only DSRs should be allowed to aggregate, as dispatchable DER and SCRs can.

Telemetry

NYISO requires DER aggregations to provide telemetry on a six-second basis, or in real time for aggregations of at least 100 kW.

Stakeholders said this requirement could be financially burdensome, particularly for smaller SCRs.

Aaron Breidenbaugh, senior director of regulatory affairs at aggregator CPower Energy Management, said the proposal would be uneconomical for SCRs below 5 MW.

"We've seen the numbers for our customers that range between $10 [thousand] and $30,000 for telemetry," he said.

"And certainly, the vast majority of existing SCR resources are below five MW."

Breidenbaugh also questioned the ISO's commitment to incorporating stakeholder input.

"I think [the report] is misrepresenting this concern. … The issue we have with respect to telemetry isn't just for small customers, it is more pronounced with smaller customers, but this is a big barrier for all sizes," Breidenbaugh said.

Expanded SCR Program Rejected

Stakeholders had urged expansion of the SCR program, saying many SCRs are now capable of operating for longer than the four-hour minimum requirement and can respond in less than the minimum 21-hour notice they now receive.

But ISO staff said the program requires extensive manual processes, making expansion impractical. Expanding the SCR model also would continue reliance on out-of-market actions,

NYISO News

contrary to the need for more grid adaptability due to increased penetration of intermittent generating resources and storage, staff said.

Rules allowing SCRs to have multiple energy duration limits and startup/shutdown times would require the ISO "to call on them individually like DER," staff said in the presentation. "NYISO would no longer be able to call SCRs to activate based on load zones."

NYISO proposed using its existing DER participation model software instead of modifying the SCR program, saying it adds flexibility and cost efficiency to grid operations.

"Adding the stakeholder-requested flexibility to these processes is expected to affect the ability of NYISO grid operators to respond to system conditions quickly and efficiently," the report said. "Making the requested modifications to the SCR program would require grid operators to understand the unique operating characteristics of individual SCRs to determine which resources are best positioned to respond to a given set of conditions."

The ISO recommended maintaining the SCR program for the time being due to its simplicity, acknowledging that the DER model is more complex. "The NYISO does not intend to eliminate or modify the SCR model at this time, providing existing and future DSRs flexibility to choose the participation model that best fits their operating characteristics," the report said.

ISO staff also rejected stakeholders' request to eliminate the ISO's proposed 10-kW minimum size for individual DER participation, which they have called discriminatory and counterproductive. (See *Clean Energy Groups Protest NYISO DER Proposal*.)

Staff said eliminating the threshold could significantly increase the number of small DER seeking to enter New York markets, increasing administrative costs. Staff also noted that software automation being developed for Order 2222 compliance that could help will not be in place until at least 2026.

Stakeholder Feedback

Stakeholders at the ICAP/MIWG meeting criticized the EtDS report, the ISO's project prioritization process and what they called a lack of clarity on next steps.

De Vito Trinsey said the ISO was simply going through a "check the box" exercise rather than making a genuine effort to enhance demand-side participation.

Julia Popova, NRG Energy's manager of regulatory affairs, concurred, questioning why ISO staff's only recommendation was to explore the development of a day-ahead DER enhancement. "This issue seems to address only one issue among many that were raised [in previous conversation], so why was this the winning issue?" she asked.

Francesco Biancardi, a market design specialist with NYISO, responded, "We're trying to find a path that both addresses external stakeholder feedback and addresses NYISO's concerns regarding reliability and market efficiency. So a day-ahead demand response enhancement seemed like a good way to check all those boxes."

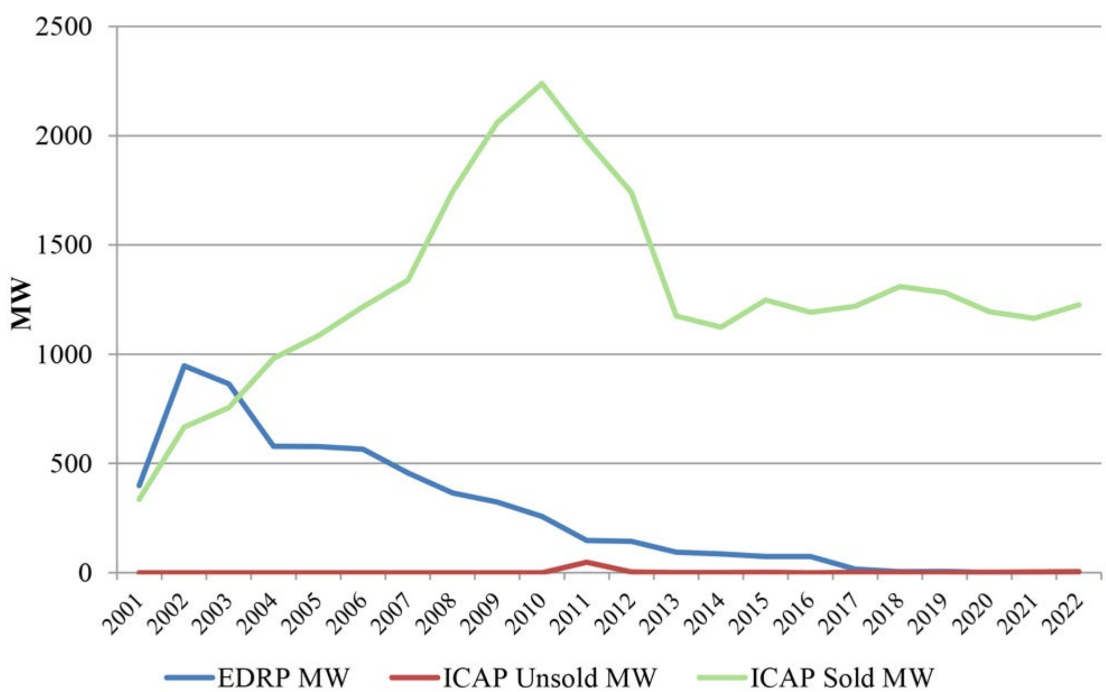
De Vito Trinsey asked the ISO to explain why it hired a consultant to examine only small-scale residential DERs and not anything else within the demand-side program.

James Sweeney, a senior attorney with the ISO, responded that the consultant was hired because ISO staff did not have the bandwidth to study a group of resources that were not originally part of the EtDS project and which they were not experts in.

These specific concerns were compounded by stakeholders' belief that the ISO failed to heed the warnings expressed previously.

"The assumption [from NYISO] is that moving demand response, particularly large customers, to the DER model will go smoothly," Brew said, "and that seems to disregard the repeated comments that were raised by others regarding DER participation."

Breidenbaugh had a similar view, saying, "If you're holding [this day-ahead recommendation] as the principal outcome of this Engaging the Demand Side effort, you're essentially ignoring all of the input that you got from stakeholders during this process." ■



Historical enrollment in NYISO's EDRP and ICAP/SCR programs by MW | *NYISO*

PJM News

Federal Court Rules in Favor of Transource Congestion Project in PJM

Project Must Clear New PJM Benefit-Cost Review to Proceed

By Devin Leith-Yessian and K Kaufmann

A federal court has ruled that the Pennsylvania Public Utility Commission violated the Constitution's Commerce Clause in denying Transource Energy a certificate of public convenience to construct the Independence Energy Connection (IEC) transmission project, ruling that the rejection was rooted in economic protectionism rather than siting concerns (*1:21-CV-01101*).

To proceed, however, the project will have to clear a new PJM benefit-cost analysis that considers other transmission projects approved in the last several years. (See *Transource Challenges Pa. PUC Decision in Court*.)

"After carefully considering defendants' arguments, the court is not persuaded that the PUC's decision was, in substance, about siting. Much of defendants' argument attempts to deconstruct PJM's analysis, following FERC-approved methodology, for assessing the project. Defendants' argument picks apart the FERC-approved methodology and whether it was sufficiently open, allowed for evidentiary hearings, permitted cross-examination or allowed argument by interested parties. But in making these arguments about the various flaws in PJM's analysis of the need for the project, defendants have not provided a substantive basis for this court to conclude that the PUC's decision actually related to siting as opposed to determining whether there was a need for the project," Judge Jennifer Wilson wrote for the U.S. District Court for the Middle District of Pennsylvania in a decision released Dec. 6.

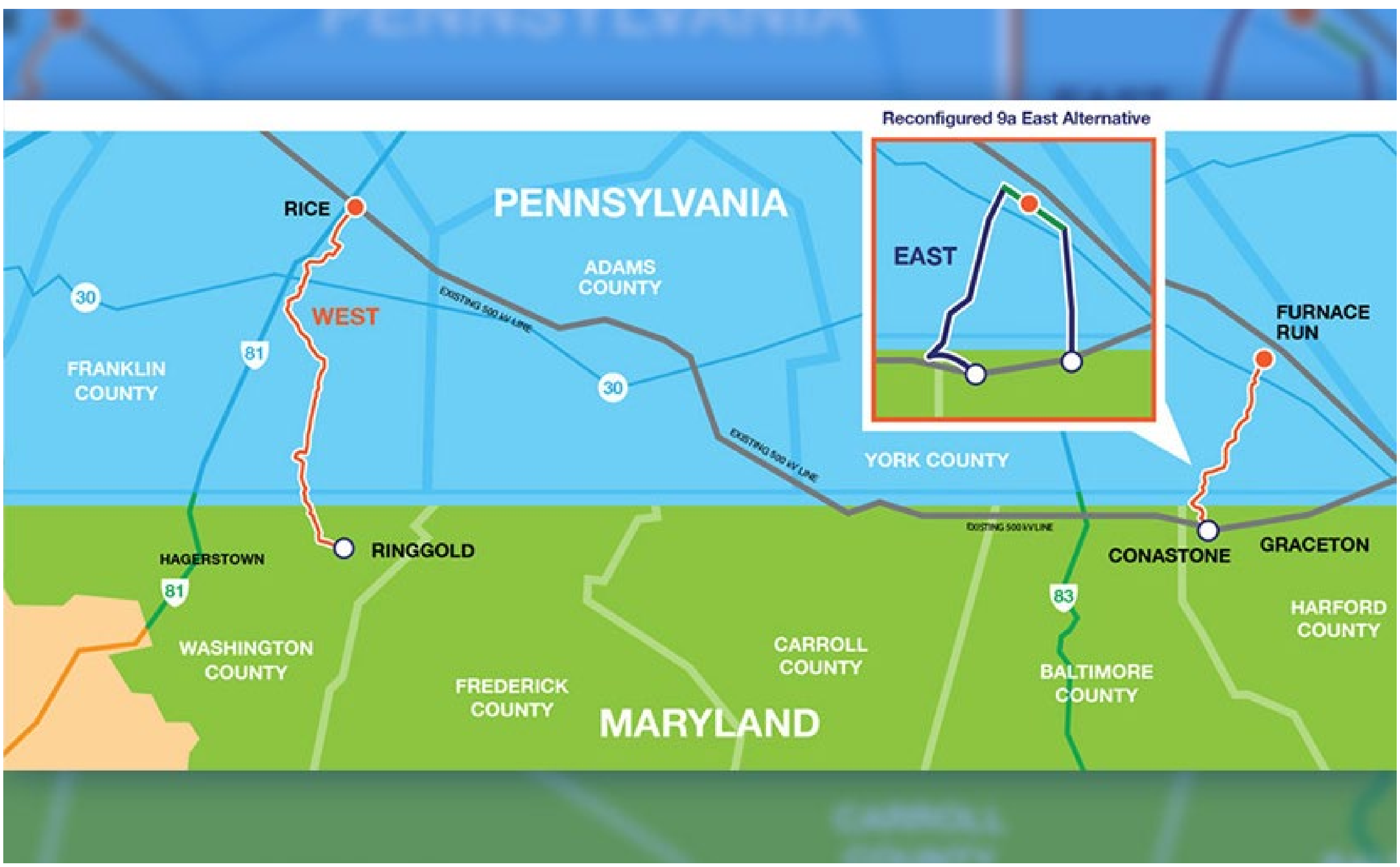
The project is aimed at alleviating congestion on PJM's AP South interface by constructing two 230-kV lines between Ringgold substation in Washington County, Md., to the Rice substation in Franklin County, Pa., and between the Conastone substation in Harford County, Md., to the Furnace Run substation in York County, Pa.

The PJM Board of Managers approved the project in 2016, stating that it was the most cost-effective way of addressing congestion in Virginia, Maryland, D.C. and western Pennsylvania. (See "Transource Re-evaluation," *PJM TEAC Briefs: Nov. 30, 2021*.)

The Maryland Public Service Commission also approved the Maryland sections of the project in June 2020 in a settlement that included a reconfiguration of the Harford County section of the project to run in an existing Baltimore Gas and Electric right-of-way.

Due to the denial and Transource's subsequent litigation, the PSC has granted the company and BGE a series of extensions on the deadlines for beginning and completing construction of the lines.

On Dec. 13, the PSC approved a third extension, to Dec. 31, 2024.



Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project | *Transource*

PJM News

Similar extensions have also been approved for another component of the IEC, a Potomac Edison rebuild of an existing single-circuit 138-kV transmission line to a 230-kV transmission line between the Ringgold and Catoctin substations in Frederick and Washington counties, Md. Speaking at the PSC meeting Dec. 13, J. Joseph Curran III, an attorney with Venable and counsel for Transource, said the litigation was the primary driver of the extension requests.

The PUC defended its May 2021 decision to deny siting and eminent domain permits by arguing that the benefit-cost analysis PJM conducted didn't address all the requirements for a project deemed to be necessary under state law and didn't take into account the full breadth of costs — namely the increased rates some will pay should congestion be alleviated.

PJM's market efficiency process considers whether the reduction in rates attributed to the project would outweigh its construction costs at a 1.25-to-1 ratio. In a 2020 reanalysis of the project, PJM estimated that it would reduce congestion costs $845 million and cost $509 million to $528 million, which would be assigned to ratepayers in the regions benefiting from the reduced congestion. (See *Transource Tx Project Rejected by Pa. PUC*.)

Transource argued that the commission was seeking to preserve the cheap power enjoyed in some areas at the expense of others without access to that energy due to congested lines. The company told the court that if states were to be permitted to reject projects on the basis that they don't benefit their ratepayers, it would defeat the purpose of transmission planning aimed at alleviating congestion resulting in regional price disparities.

"If states could override FERC by applying a conflicting method for determining need, solely to preserve the benefits of congestion for their own citizens, that would eviscerate FERC's ability to plan the interstate transmission grid in an efficient and fair manner," Transource said in court documents.

The court rejected the PUC's jurisdictional arguments, stating that the federal government's interests go beyond planning projects and extend to seeing that they are built, with the states' role focused on enforcing local siting, environmental and public safety regulations.

"The PUC is attempting to supplant the role of the RTO and expand its state authority into the regulatory territory occupied by the federal government. If permitted, the PUC's second-guessing of the methods sanctioned by federal law and employed by the RTO would severely handicap the ability of FERC to ensure just and reasonable rates. Because the PUC's decision presents an obstacle to achieving federal objectives, it is conflict preempted and violates the Supremacy Clause," the court wrote.

The commission also argued that the congestion had decreased since 2014 and the project's benefits would be lower than presented in PJM's 2016 approval of the IEC project. The benefits would be further diminished, the commission said, if the benefit-cost analysis included the increased rates that might manifest once the congestion was eliminated.

PJM Re-evaluates

While welcomed by Transource, the federal court decision does not mean IEC is out of the woods. First, the PUC has 30 days to file an appeal, and some local permitting remains.

However, Hector H. Garcia-Santana, senior counsel for American Electric Power, which partnered with Evergy to form Transource, told the PSC on Dec. 13 the IEC projects are "very mature at this point. Materials are in the United States, and they are specific for the project. They are already in hand. The transformers, which are long-lead items, are already in the United States as well. … They were acquired at a time prior to now; so, the price for that type of equipment has increased since then."

Garcia-Santana added that 70% of the rights of way for the projects have been secured, as well as rights for substations in Pennsylvania. Pending final approvals from the PUC, construction could take 12 to 18 months, he said.

Garcia-Santana's optimism was somewhat tempered by William Fields, deputy people's counsel in the Office of the People's Counsel, who cautioned that PJM will be re-evaluating IEC in the spring of 2024 to consider whether it is still cost-effective and necessary "because of all the tremendous activity going on in this general area of the grid."

Since IEC was originally approved, New Jersey has selected its first projects under its state agreement approach with PJM, intended to start building out the transmission needed for offshore wind projects, and the PJM board approved Window 3 projects for its Regional Transmission Expansion Plan (RTEP) on Dec. 11.

PJM filed a waiver request asking FERC for more time to complete its required annual reanalysis of the project in November due to how the RTEP projects could interact with the project.

"Performing a reevaluation of the Transource IEC Project before year end with a base case that does not resolve the 2022 RTEP Window No. 3 reliability violations will produce incomplete results until the market efficiency model is updated for reevaluation purposes, which will frustrate PJM's ability to provide meaningful updates to the [Transmission Expansion Advisory Committee] and the PJM Board. Either way, performing an analysis on incomplete data is an inefficient use of PJM engineers' time," the waiver request argues.

The waiver request states that PJM staff will need about three to four months to prepare a base case including the approved RTEP projects to run the analysis on whether the IEC project continues to pass the benefit-cost threshold. It asks that FERC extend the deadline for the analysis to the second quarter of 2024.

PSC members also raised concerns about the potential closing of the 1,238-MW Brandon Shores coal-fired plant outside Baltimore. PJM has said taking the plant offline in 2025, as planned by owner Talen Energy, could result in "degraded grid reliability."

Commissioner Michael T. Richard queried Fields on whether OPC or PSC staff have "had a chance to hear from PJM about how this cluster of [IEC] projects interacts with these other projects, and really, if they are still needed and cost competitive."

"We don't know exactly where PJM is going to be on that," Fields said. "But it seems a good chance that [the IEC projects] have been overtaken by events from these other activities. I think the real question is going to be, in the spring, when PJM runs the power flow models … [will] they look and say, 'How much is this going to save in market prices over the future, from that point on?' And you compare that to the cost of the project."

Fields told *RTO Insider* his office would support the project if it continues to promise the benefit-to-cost ratio PJM has projected in the past. However, he noted that it was approved years ago and the grid in that region has seen a lot of change.

"There's been a huge amount of activity in this part of PJM with respect to new transmission that's already been built, transmission that's planned to be built, generation retiring and I think it's an open question whether when PJM reevaluates the costs and benefits of this plan, if it's still going to be beneficial in reducing customer's energy bill," he said. ■

PJM News

PJM Board Approves $5 Billion Transmission Expansion

By Devin Leith-Yessian

The PJM Board of Managers on Dec. 11 approved an estimated $5 billion package of transmission projects in the third window of its 2022 Regional Transmission Expansion Plan.

In its *announcement* of the approval, PJM said it is forecasting 7,500 MW of new data center load in Virginia and Maryland, much of which is expected to be clustered around Dulles Airport in Northern Virginia. The RTO is also expecting about 11,000 MW in generator deactivations, most notably the 1,295-MW Brandon Shores plant outside Baltimore.

The package is made up of dozens of components submitted by Dominion Energy, FirstEnergy, Exelon, PPL, NextEra Energy, Transource Energy and Public Service Enterprise Group. (See "Second Read of $5 Billion in RTEP Projects," *PJM PC/TEAC Briefs: Dec. 5, 2023*.)

The work includes constructing new 500-kV lines from Northern Virginia northeast to the Peach Bottom substation in Pennsylvania, northwest to the 502 Junction substation in West Virginia and south to the Morrisville substation in Southern Virginia.

The board's approval caps off a process that began with the opening of the competitive window for transmission owners to submit projects in February. The normal 90-day window was extended to close May 31, and PJM presented three shortlisted packages on Oct. 3 before an Oct. 31 presentation of the proposal to the Transmission Expansion Advisory Committee that it ultimately brought to the board. (See *PJM Shortlists 3 Scenarios for 2022 RTEP Window 3*.)

Maryland Office of People's Counsel Deputy William Fields told *RTO Insider* that presenting the recommended set of projects at the end of October with the plan of bringing it to the board in December left little time for stakeholders and the public to evaluate the projects and draft comments to the board to allow them to come to a fully informed decision.

"It's certainly true that this general issue has been talked about for many months, but we saw this actual list of projects Oct. 31 ... and here it is weeks later being approved," he said Wednesday.

Fields said his office had received high-level information about cost allocation from PJM on Dec. 12 and is in the process of evaluating the potential impact to Maryland ratepayers.

The functioning of the cost allocation formula in PJM's tariff is understood by stakeholders, but Fields said that the scale of the package will present that methodology with a test it has yet to face.

"We've just gotten some preliminary information, and we're trying to evaluate it and look at it in more detail. But the question is, does the usual allocation method produce reasonable results when you're talking about extremely large amounts of new load?" he said.

During the second read of the proposal at the TEAC meeting Dec. 5, several members of the public objected to the package, citing concerns about disruption to historic regions along the proposed route, the inclusion of greenfield construction components, the cost and the likelihood of requiring additional major transmission expansions should load growth continue in the region.

PJM Board of Managers Chair Mark Takahashi | © RTO Insider LLC

PJM's Sami Abdulsalam said the proposal represented the most efficient, cost-effective and resilient combination of the 72 project submissions received during the competitive window and that minimizing greenfield disruption and siting risk were among staff priorities. The RTO included with its TEAC meeting materials an FAQ detailing its role in selecting the proposals in the window. ■

PJM News

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings. 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 the next newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

B. Endorse conforming *revisions* to Manual 12, Balancing Operations; Manual 13, Emergency Operations; and Manual 14D, Generator Operational Requirements to implement a renewable dispatch package. (See "Other Committee Business," *PJM MIC Briefs: Nov. 1, 2023*.)

Issue Tracking: *Renewable Dispatch*

C. Endorse proposed *revisions* to Manual 14B, PJM Region Transmission Planning Process as a part of its periodic review. The changes include specifying that the 300-MW load loss rule is meant to apply to possible outages that would affect a large number of consumers, rather than a single large industrial customer. (See "First Read of Periodic Review of Manuals 19 and 14B," *PJM PC/TEAC Briefs: Oct. 3, 2023*.)

D. Endorse conforming *revisions* to Manual 21A, Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis addressing Hybrids Phase II Market Participation of Hybrid Resources and other Mixed Technology Facilities instituting the second phase of PJM's rules for hybrid resources.

Issue Tracking: *Solar-Battery Hybrid Resources*

E. Approve sunsetting the Energy Price Formation Senior Task Force (EPFSTF).

Issue Tracking: *Operating Reserve Demand Curve (ORDC) & Transmission Constraint Penalty Factors*

Endorsements (9:10-9:55)

1. **Performance Impact of the Multi-schedule Model on the Market Clearing Engine (9:10-9:30)**

PJM's Danielle Croop will *present* the proposal endorsed by the Market Implementation Committee on Aug. 9 to revise how some resource offers are entered into the market clearing engine (MCE) to allow multi-schedule modeling to be implemented without overloading the engine with an exponential increase in the number of schedules it must consider. Croop also will present an alternative approach which received lesser MIC support, but still a majority. (See "Endorsement of Multi-schedule Modeling Solution Deferred," *PJM MRC/MC Briefs: Nov. 15, 2023*.)

The committee will be asked to endorse the proposed solution and corresponding tariff and Operating Agreement revisions.

Issue Tracking: *Performance Impact of the Multi-Schedule Model on the Market Clearing Engine*

2. Regulation Market Design Senior Task Force (RMDSTF) (9:30-9:55)

Croop will present a *proposal* to shift the regulation market to have a single price signal with two products representing a resource's ability to adjust its output up or down. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Nov. 15, 2023*.)

The committee will be asked to endorse the proposed solution and corresponding tariff and OA revisions.

Issue Tracking: *Regulation Market Design*

Members Committee

Endorsements (10:10-10:20)

PJM's Michele Greening will *present* the proposed sector representatives for the 2024 Finance Committee, 2024 sector whips and 2024 MC vice chair.

The committee will be asked to elect the proposed representatives. ■

—Devin Leith-Yessian

Company Briefs

Tesla Recalls Nearly All Vehicles Sold in US to Fix Autopilot System

Tesla on Dec. 13 recalled nearly all vehicles sold in the U.S., more than 2 million, to update software and fix a defective system that's supposed to ensure drivers are paying attention when using Autopilot.

The recall comes after a two-year investigation by the National Highway Traffic Safety Administration into a series of crashes that happened while the Autopilot partially automated driving system was in use. The recall covers models Y, S, 3 and X produced between Oct. 5, 2012, and Dec. 7, 2023.

Documents say the update will increase warnings and alerts to drivers and limit the areas where basic versions of Autopilot can operate.

More: *The Associated Press*

Shell to Divest Stakes in 2 Renewable Projects

Shell subsidiaries Shell Wind Energy and Savion Equity on Dec. 11 announced they have agreed to sell their stakes in two renewable energy projects in the U.S. to InfraRed Capital Partners.

Shell has agreed to sell a 60% stake in the 182-MW Brazos Wind Holdings wind farm in Fluvanna, Texas, and a 50% stake in the 180-MW Madison Fields Class B Member solar development in Madison County, Ohio.

Both assets are expected to be sold by early 2024, with an effective date of December 2023. No financials were disclosed.

More: *Power Technology*

Ford Decreasing F-150 Lightning Production amid EV Pullback

Ford on Dec. 11 said it is decreasing production of its all-electric F-150 Lightning pickup truck after the new year at its Dearborn, Kent., factory.

A recent report cited a supplier memo that stated the automaker will produce 1,600 vehicles per week. The plant had a planned production for double that.

Ford in October said it was cutting $12 billion in planned EV investment as the growth in adoption slows.

More: *Lexington Herald-Leader*

AESC to Expand South Carolina Battery Cell Facility

AESC, an EV battery technology company, announced Dec. 12 the $810 million expansion of its battery cell facility in Florence County, S.C.

During the second of three potential phases, the company will invest $810 million and create 450 new jobs at the gigafactory. This new commitment follows AESC's initial announcement in December 2022 of $810 million and 1,170 jobs, combining for a total investment of $1.62 billion and 1,620 new jobs.

More: *SC Now*

Federal Briefs

House Passes Bill Banning Russian Uranium Imports

The U.S. House of Representatives on Dec. 11 passed a ban on Russian imports of uranium as lawmakers seek to increase pressure on Moscow for its war on Ukraine.

The bill, which would ban imports 90 days after enactment, must still pass the Senate and be signed by President Joe Biden before becoming law.

More: *Reuters*

NRC Approves Construction Permit for Hermes Reactor

The Nuclear Regulatory Commission on Dec 12 approved a construction permit for a test reactor at Heritage Center industrial park in west Oak Ridge, Tenn.

The 35-MW thermal Hermes demonstration reactor would be built by Kairos Power. The reactor will not generate electricity but instead provide operational data to support the development of a larger version for commercial power, the NRC said.

Construction of the reactor could start next year.

More: *Oak Ridge Today*

Scientists to Study How OSW Construction off Va. Beach Impacts Fish

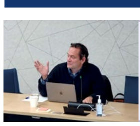
Nature Conservancy researchers, along with the federal government, are embarking on research off the Virginia Beach coast to see how driving offshore wind turbines into the seafloor impacts fish behavior.

The research will provide guidance for how the government should craft environmental regulations for offshore wind development. The research, which will be conducted through 2027, will also look at how the electromagnetic field of underwater transmission lines affects fish behavior and how construction sound could impact whales.

"We are going to tag animals in such a way that it gives us the opportunity to observe behavior and gain an understanding of how that behavior may or may not change before versus during that construction activity," said Brendan Runde, a scientist with the Nature Conservancy.

More: *Virginia Mercury*

National/Federal news from our other channels



NERC Board May Force Action on Cold Weather Standard

ERO Insider

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

State Briefs

CALIFORNIA

CalFire: Fairview Fire Triggered by Sagging Electrical Line

A Cal Fire investigatory report released last week confirmed that a sagging Southern California Edison electrical line contacted a communications cable, creating an arc that ignited the Fairview fire in 2022.

Edison, in a report to the Public Utilities Commission filed hours after the fire started on Sept. 5, 2022, said there was "very strong evidence" the utility's infrastructure ignited the blaze.

The report was provided in response to a subpoena from the attorneys for victims of the fire who have sued Edison, claiming negligence by the utility was responsible for the fire that destroyed 22 homes and killed two people.

More: *East Bay Times*

FLORIDA

Former FPL CEO Sold $5.4M in Stocks as Scandals Became Public

Former Florida Power & Light CEO Eric Silagy made $5.4 million by unloading his company's stock as ties between the utility and political consultants who orchestrated a controversial 2020 "ghost candidate" scheme spilled out into the public, a new lawsuit alleges.

The lawsuit, filed by a group of investors who purchased securities in FPL's parent company NextEra Energy, centers around Silagy's sale of 62,480 shares of the utility's stock in December 2021 — the largest number of shares he had bought or sold since becoming a company officer in 2012. Those who filed the suit had acquired securities in NextEra Energy between Dec. 2, 2021, (the day that Silagy made the sale) and Jan. 30, 2023, shortly after NextEra announced Silagy's departure from the company.

Five people have been criminally charged in connection to the scheme, including two of the ghost candidates.

More: *Orlando Sentinel*

ILLINOIS

Commerce Commission Rejects ComEd Rate Increase

The Commerce Commission on Dec. 14 rejected a new grid plan and a $1.5 billion rate increase sought by ComEd, saying the proposal "failed to comply" with a sweeping clean energy law signed two years ago by Gov. J.B. Pritzker (D).

ComEd's proposed rate hike would have raised the average Chicago-area bill by $6.72 next year, with subsequent yearly hikes totaling $17 by 2027. An administrative law judge previously suggested the commission cut ComEd's rate hike down to $400 million, but the panel tossed out the rate plan completely.

ComEd said the hike was the cost of beefing up the grid for the climate legislation, which also has a goal of rolling out a million EVs by 2030. Additionally, the utility said it needs to better equip its system for severe weather.

More: *Chicago Sun-Times*

LOUISIANA

State Issues First-ever OSW Leases

Louisiana on Dec. 13 approved the state's first-ever wind energy operating agreements in offshore waters at the State Mineral and Energy Board meeting.

Gov. **John Bel Edwards** (D) and Department of Natural Resources Secretary Tom Harris announced the approval of two projects, one off the coast of Terrebonne and Lafourche parishes and another in Cameron Parish's coastal waters. The Diamond Offshore Wind site is on 6,162 acres offshore from Terrebonne and Lafourche, while the Cajun Wind development will cover 59,653 acres off Cameron's coast.

The Diamond property agreement paid $308,101 upfront and will submit 1.5% of its gross revenues in royalties over the life of the agreement. Cajun Wind first paid $357,923 for its agreement and will pay 2.2% in royalties.

More: *Louisiana Illuminator*

MAINE

CMP, Versant Sue State Over Foreign Electioneering Referendum

Central Maine Power Co. and Versant Power, along with two press groups, sued the state Dec. 12, claiming a referendum that looks to ban foreign electioneering in the state violates their First Amendment rights.

The three separate lawsuits were filed in the U.S. District Court in Portland. One each came from CMP and Versant Power, while another was jointly filed by the Maine Association of Broadcasters and the Maine Press Association.

The move puts the utilities and outlets at odds with the 86% of voters who backed Question 2 on the November ballot that sought to ban foreign governments, and companies that are at least 5% owned by them, from influencing candidate or referendum elections in the state.

More: *Bangor Daily News*

MASSACHUSETTS

Energy Facilities Siting Board Approves Craigville Beach Tx Line

The Energy Facilities Siting Board on Dec. 11 unanimously approved a proposal by Avangrid to bring an offshore wind transmission line ashore at Craigville Beach in Barnstable.

The transmission line slated to come ashore at Craigville Beach is from a wind farm called Park City Wind, also being developed by Avangrid. A third Avangrid wind farm called Commonwealth Wind is aiming to come ashore at Dowses Beach, also in Barnstable.

The board approved the project after adopting several amendments to a staff-written decision and requiring Avangrid to meet with Barnstable officials to address the town's concerns. The board required Avangrid to report back on its dealings with Barnstable by Jan. 5.

More: *CommonWealth Beacon*

NEW HAMPSHIRE

Eversource Proposes Significant Rate Cut

Eversource is proposing a rate cut of about 35% for the average residential bill.

Last year customers were paying more than 20 cents per kWh. Currently, the rate is 12.58 cents, and under the proposal, it would drop to 8.29 cents.

The rate needs to be approved by the Public Utilities Commission. If approved, it will go into effect from Feb. 1 through July.

More: *WMUR*

NEW YORK

Con Ed Outage Leaves People Stranded in Elevators Overnight Across NYC

A Con Edison power outage caused issues citywide overnight Dec. 14, with reports of people stuck in elevators and delays on the subway.

Smoke was seen billowing from the Farragut Electrical Substation in Brooklyn just before midnight. Con Edison President Matt Ketschke said employees were restoring a transmission line when a piece of high voltage electrical equipment failed.

While the outage was brief, it caused serious issues for elevators citywide, including at Grand Central and Penn Station, where they were out for around three hours. Overall, 178 elevators and escalators were impacted, and two people got stuck in elevators.

More: *CBS New York*

RHODE ISLAND

CRMC Approves Sakonnet River Tx Line

The Coastal Resources Management Council (CRMC) on Dec. 12 unanimously voted to approve an underwater transmission line planned as part of the SouthCoast Wind project.

The CRMC gets to weigh in on any development within 30 miles of the coastline through its Ocean Special Area Management Plan. The actual turbines are outside the council's purview, in an area 60 miles south of the coastline. However, 50 miles of the high-voltage, undersea cables connecting the turbines to the onshore grid are within the agency's scope of review.

A separate application for a CRMC permit for the project remains under review.

More: *Rhode Island Current*

VIRGINIA

Prince William County Approves Data Center Project

The Prince William County Board of Supervisors last week voted 4-3, with one abstention, in favor of the Digital Gateway project that would bring as many as 37 data centers over about 2,000 acres in the western part of the county.

The vote in favor of the Digital Gateway came despite a recommendation from the county planning commission that the project be rejected.

Prince William County projects the data centers will generate hundreds of millions of dollars annually in tax revenue.

More: *The Associated Press*

WYOMING

Rocky Mountain Power to See Rate Increase Starting in January

Rocky Mountain Power customers will see a rate increase of about 8.3% starting in January.

The increase, which will amount to $54 million annually, was approved by the Public Service Commission in November. However, the PSC must still verify the calculations and give a final approval in a written order due before the end of December.

The company had originally asked for an increase of 21.6%.

More: *WyoFile*