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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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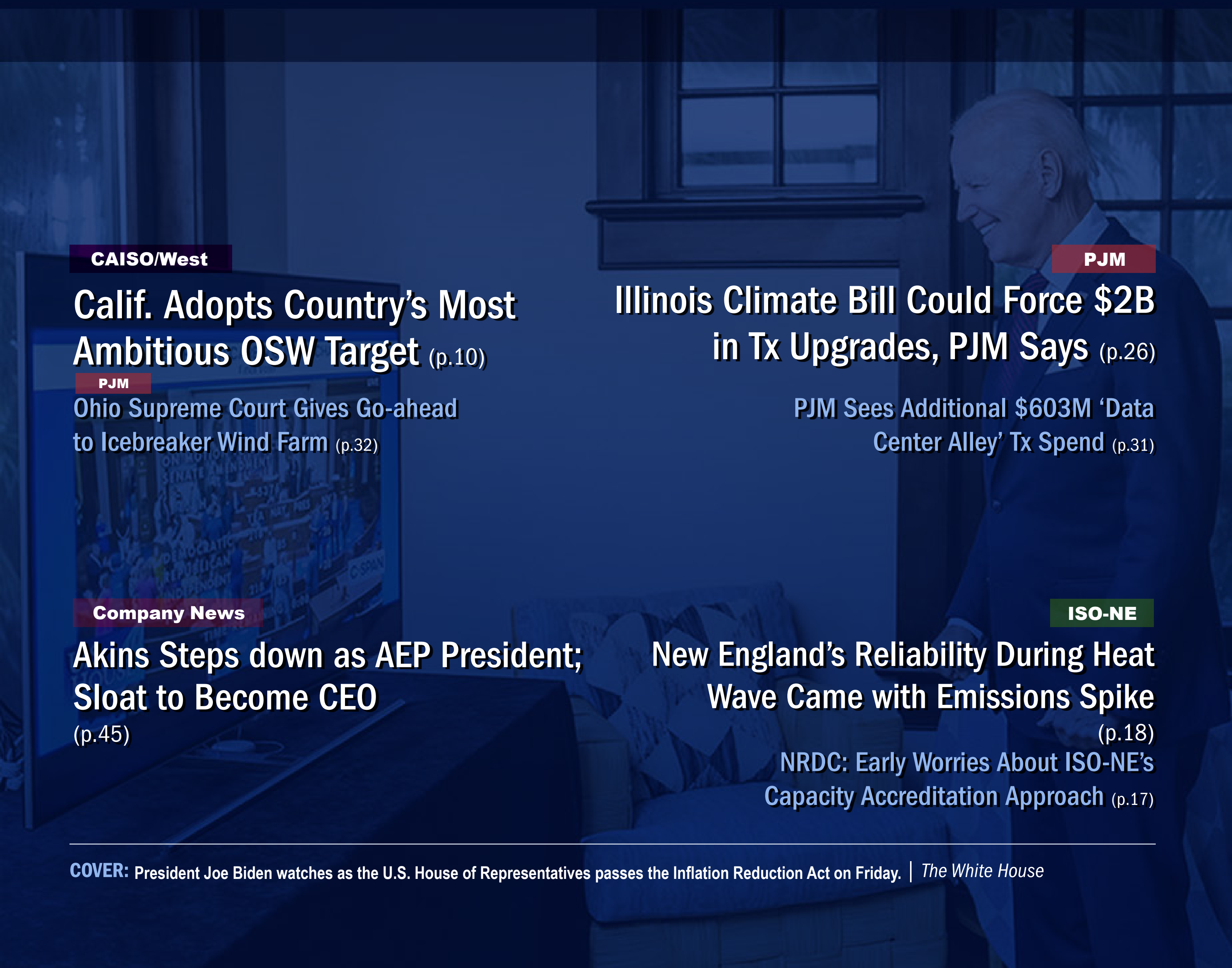

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COVER: President Joe Biden watches as the U.S. House of Representatives passes the Inflation Reduction Act on Friday. | *The White House*

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In this week's issue

FERC/Federal News

House Passes Inflation Reduction Act, Sends to Biden

President Will Sign 'Historic' Bill Next Week

By K Kaufmann

The U.S. House of Representatives passed the Inflation Reduction Act (*H.R. 5376*) on Friday, sending the $740 billion package of tax, health and climate provisions to the White House for President Biden's signature.

Democratic representatives standing before the speaker's dais broke out in cheers and high-fives as Speaker Nancy Pelosi (D-Calif.) announced the final vote of 220-207, with four Republicans not voting.

Earlier in the day, Pelosi had vowed that once passed, the bill would head straight to Biden's desk. "It will be ready in a matter of minutes for me to enroll it, and it will go directly to the president for his signature," she said.

Biden, who watched the vote at the White House, quickly tweeted he would sign the bill in the coming week and also announced a celebration of the soon-to-be law on Sept. 6.

Passing the IRA "required many compromises. Doing important things almost always does," Biden said.

National Climate Adviser Gina McCarthy was among other administration officials hailing the vote on Twitter, calling the IRA's $369.75 billion in clean energy funding "our biggest climate investment ever, by far. This will save so many lives and create so many opportunities," McCarthy said, crediting the bill's success to "a broad, steadfast movement demanding a clean energy future."

Senate Majority Leader Chuck Schumer (D-N.Y.), who negotiated the compromise version of the IRA with Sen. Joe Manchin (D-W. Va.), also took to social media, calling the IRA "the boldest climate package in U.S. history. … The Democrats got it done!" he said.

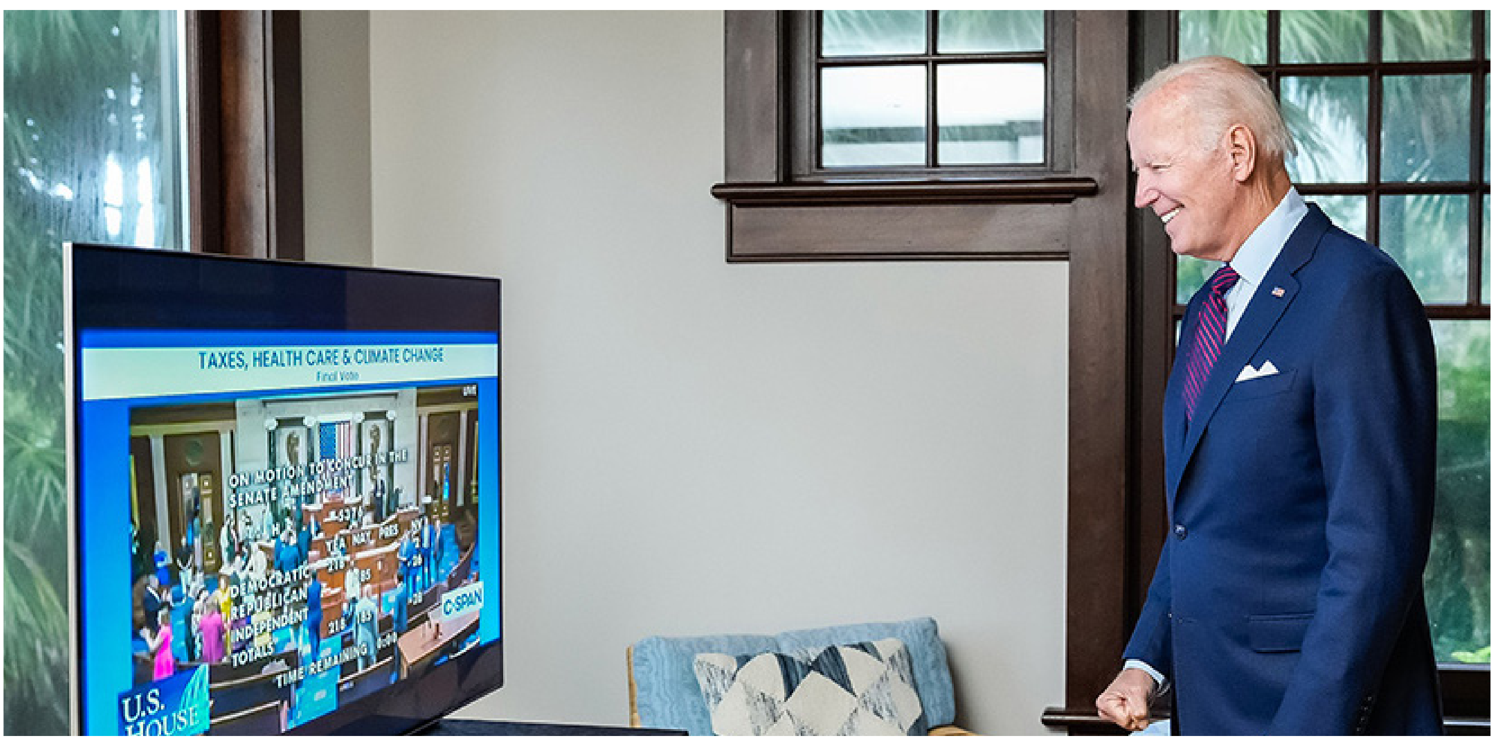
The party-line vote followed more than three hours of heated debate with Democrats and Republicans exchanging familiar arguments — and mid-term election talking points — about the bill's impacts, mostly in one-minute speeches on the floor. Republicans hammered away on claims that the bill on would increase taxes and inflation, and set IRA agents on working Americans, while Democrats hit back with bill provisions that would cap prescription drug costs for seniors on Medicare and accelerate the country's shift to clean energy while lowering utility bills.

House Minority Leader Kevin McCarthy argued that under the IRA, "your energy prices will now go through the roof. I look forward to every Democrat who votes for this bill … [explaining it] to their constituents when they're making a choice about whether they pay [for] the energy to heat their homes, or they cut back on the gas to fill their tank."

"We have a climate crisis, and the deniers have undermined our ability to respond," countered Majority Leader Steny Hoyer (D-Md.). "This bill responds and … consistent with the desires of the American people, will bring down the cost of energy for Americans by investing in developing and deploying cleaner, more sustainable energy technologies like electric vehicles and solar panels."

Rocky Path to Passage

The version of the IRA that passed Friday has traveled a rocky path since September 2021, when Democrats first unveiled it as the $3.5 billion Build Back Better Act, a filibuster-proof budget reconciliation package with a range of social spending and clean energy incentives. Faced with opposition from the Senate's centrist Democrats, Manchin and Sen. Krysten



President Joe Biden watches as the U.S. House of Representatives passes the Inflation Reduction Act on Friday. | *The White House*

FERC/Federal News

Sinema (D-Ariz.), Biden in October negotiated a trimmed-down BBB framework set at $1.75 trillion.

The House passed its version of BBB on Nov. 19, with a $2.2 trillion price tag, adding spending on progressive priorities such as four weeks of paid family and medical leave. BBB then went to the Senate, where negotiations hit a wall in December when Manchin walked away from further discussions.

"I have always said if I can't go home and explain it to the people of West Virginia, I can't vote for it," Manchin said on Dec. 19 on "Fox News Sunday." "And I cannot vote to continue with this piece of legislation. I just can't. … This is a no."

At the time, Manchin said the government should focus on inflation and the year-end surge in COVID-19 cases, driven by the fast-spreading Omicron variant. (See *Manchin Says 'No' on Build Back Better*.)

Manchin and Schumer resumed negotiations on the bill earlier this year, but Manchin balked at rising inflation figures in July, and once again appeared to close down talks on the legislation. (See *Biden: 'I Will not Back Down' on Climate Action*.)

The surprise announcement of a deal on the renamed Inflation Reduction Act came on July 27, followed by passage in the evenly split Senate on Aug. 7 — 51 to 50 — with Vice President Kamala Harris casting the tie breaking vote. (See *Senate Passes Inflation Reduction Act.*)

Senate Republicans offered dozens of amendments during the Senate debate, two of which passed. A $35 per month cap on insulin prices for consumers with private insurance was stripped from the bill but was retained for Medicare patients. A second amendment revised the bill's 15% corporate minimum income tax, exempting companies owned by private equity from the provision.

Prior to Friday's debate, House Democrats also passed a resolution setting out the rules for the debate, which specifically closed off any attempts to further amend the bill. Under the rules for budget reconciliation, any changes in the House would have required the IRA to go back to the Senate for a second vote and possibly more Republican amendments.

'Fully Unleashed'

For clean energy advocates and industry groups, the IRA's expansion and extension of renewable energy production and investment tax credits was a big win. The bill extends existing wind and solar tax credits through the end of 2024 and then transitions them to technology neutral clean energy tax credits that continue through 2032. A direct pay provision also allows nonprofit organizations, including electric cooperatives, to access the tax credits, which they have been unable to do. (See *What's in the Inflation Reduction Act, Part 1*.)

"Electric cooperatives are leading the charge to reliably meet America's future energy needs amid an energy transition that increasingly depends on electricity to power the U.S. economy," National Rural Electric Cooperative Association CEO Jim Matheson said. "As co-ops continue to innovate, access to tax incentives and funding for investments in new energy technologies are crucial new tools that will help reduce costs and keep electricity affordable for consumers."

Tom Kuhn, CEO of the Edison Electric Institute, the trade association for investor-owned utilities, said the 10-year time horizon for the credits will provide "much needed certainty to America's electric companies over the next decade as they work to deploy clean energy and carbon free technologies. … This legislation firmly places the United States at the forefront of global efforts to drive down carbon emissions, especially when paired with the historic [research, development and deployment] funding" in the Infrastructure Investment and Jobs Act, he said.

CEO of Advanced Energy Economy Nat Kreamer called out the bill's tax credits for solar, storage and other clean energy manufacturers. "Clean energy technologies

House Speaker Nancy Pelosi announces the passage of the Inflation Reduction Act. | *CSPAN*

will be fully unleashed," Kreamer said. "Clean energy manufacturers and developers alike will now have the right financial tools and the policy certainty they need to produce and buy the components that power these innovative technologies here in America."

Other provisions of the IRA expand the 45Q tax credit, which had been a particular focus for the carbon capture industry. The bill ups the per ton incentives for carbon and direct air capture, for example, from $50 to $85 per ton for carbon sequestered in geologic saline formations, and also provides a direct pay option.

Madelyn Morrison, external affairs manager for the Carbon Capture Coalition, said the IRA "reinforces the essential role carbon management must play in achieving midcentury climate goals while providing a critical pathway to creating and retaining the high-wage jobs base communities and families depend upon, and positioning our nation's industrial, energy and manufacturing sectors as leaders in technology innovation." (See *What's in the Inflation Reduction Act, Part 2*.) ■

"This legislation firmly places the United States at the forefront of global efforts to drive down carbon emissions."

—Tom Kuhn, CEO, Edison Electric Institute

FERC/Federal News

How Much Will the IRA Cut GHG Emissions, Home Energy Costs?

Emissions Increase from Oil and Gas Leasing Provisions Offset by Power Sector Cuts

By K Kaufmann

A panel of industry analysts Wednesday presented their estimates of how much the Inflation Reduction Act would reduce greenhouse gas emissions and its impact on average household energy costs.

The webinar hosted by Resources for the Future (RFF) came as the House of Representatives prepared to vote on the bill and its $369.75 billion in clean energy funding, which the Senate passed on Aug. 7. (See *Senate Passes Inflation Reduction Act*.)

Rhodium Group found that the average household savings from the IRA would run from a low of $27 per year to a high of $112 per year, depending on natural gas prices.

RFF's own analysis of the bill forecasts a 5 to 7% cut in retail electricity prices by 2030, which could translate to per kilowatt-hour savings of about a half to one-and-a-half cents by 2030, again depending on natural gas prices.

"Between low and high natural gas prices, there's roughly a swing of about over 10% in terms of retail electricity prices," said Kevin Rennert, RFF's director of federal climate policy.

But, he said, "having the IRA in place — and the clean electricity that is driven by the policy and incentives — actually reduces the effects of variability within natural gas. … Having more electricity on the grid certainly insulates you against price shocks."

While they differed on details, all the speakers at the webinar agreed that their respective modeling programs found the IRA will provide energy savings across a range of variables. They also agreed that however sophisticated their software, some aspects of the bill would be hard to quantify.

Jesse Jenkins, head of Princeton University's Zero carbon Energy systems Research and Optimization (ZERO) Laboratory, pointed to siting constraints for solar, wind and carbon capture projects. Examples include "the ability to scale up the workforce to deploy resources at this scale and the ability to expand networks like transmission and CO_2 pipelines and storage to support this level of growth," he said.

Clean Energy Incentives

In addition to natural gas prices, RFF's analysis also factored in the potential clean energy incentives contained in the IRA, resulting in different scenarios with base and bonus levels of incentives. For example, the bill's proposed technology-neutral clean energy investment tax credit (ITC), beginning in 2025, has a base of 6% of projects costs, but can be multiplied by five, to 30%, for meeting certain prevailing wage and apprenticeship requirements. (See *What's in the Inflation Reduction Act, Part 1*.)

The technology-neutral incentives are "a big deal because it no longer will require an act of Congress for a new technology to be eligible for these credits," Rennert said.

Another plus: the bonuses are "stackable" so that a single project can receive multiple bonus incentives, such as a bonus for meeting the prevailing wage and apprenticeship requirement and a second for project location in an "energy community" affected by the closure of a fossil fuel plant.

With such stackable bonuses, a project could earn a 50% ITC, Rennert said, and help slash GHG emissions from the power sector by as much as 75% — or an additional 4 billion tons of greenhouse gas emissions — below 2005 levels.

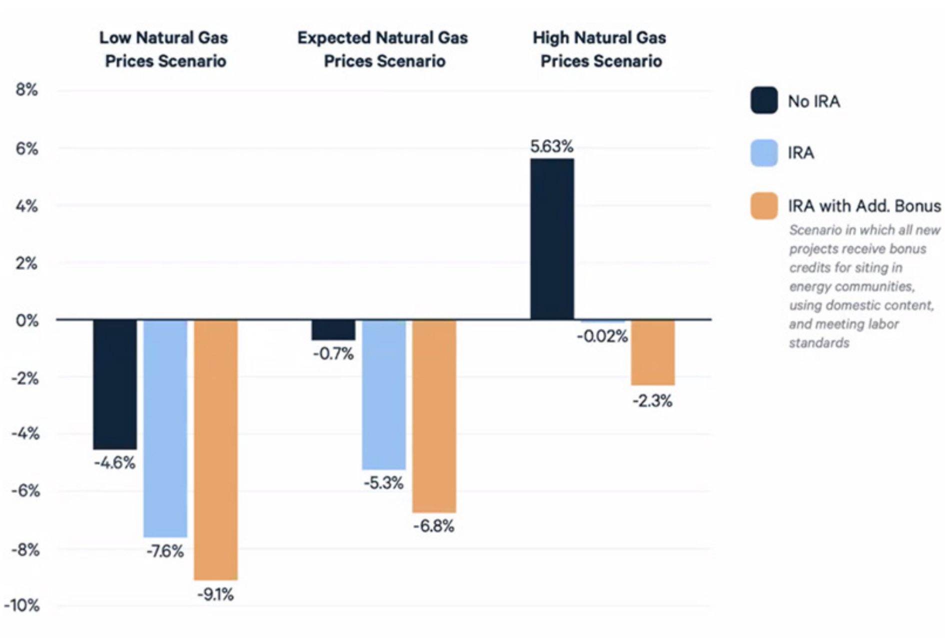
The ZERO Lab analysis also said the IRA's clean energy incentives would cut power sector emissions 75% but pegged cumulative GHG emission reductions at 6.3 billion tons by 2030.

"The bill primarily reduces emissions by making clean energy cheaper," Jenkins said. "It's about making it cheaper and easier for businesses, for utilities, for households, for everyone across America to adopt cleaner energy sources, to make more efficient choices about upgrades to their businesses or homes and to electrify energy consumption in buildings and transportation."

The law "could spur record-breaking growth in wind and solar capacity" depending on "how fast we can grow and continue smashing records each year," he said.

While the U.S. added 15 GW of wind and 10 GW of solar in 2020, the ZERO Lab analysis shows the IRA more than doubling wind to 39 GW by 2030 and increasing solar almost fivefold to 49 GW.

Jenkins also sees the bill's clean energy incentives having a ripple effect, making it "easier and cheaper for states or cities or companies at any level across the country to increase their climate ambitions. It also reinforces the economic benefits of any future federal regulations," he said.



Changes in retail electricity rates from 2023 to 2032, without and with the Inflation Reduction Act | *Resources for the Future*

FERC/Federal News

Oil and Gas Leasing

Both Rennert and Robbie Orvis, senior director of energy policy design at industry consultants Energy Innovation (EI), looked at the potential increase in GHG emissions that could be caused by the IRA's oil and gas leasing provisions. The bill requires the Department of the Interior to complete stalled oil and gas leasing auctions in the Gulf of Mexico and off the coast of Alaska.

It also links the permitting of solar and wind projects on federal land to corresponding sales of onshore and offshore oil and gas leases.

RFF estimates the new leases will generate about 20 million metric tons of GHG emissions by 2030, a figure that would be more than offset by the 4 billion-ton cut in emissions from the electric power sector, Rennert said.

Orvis detailed EI's modeling assumptions — that 2% of the millions of acres available for oil and gas leasing would actually be sold at auction, and emissions from any wells drilled would be spread out over time. EI's conservative estimate of emissions from those wells came in at 50 million MT, Orvis said.

"And that means for every one-ton increase in emissions from the oil and gas lease provisions [in the IRA], there's 24 tons of emissions reductions from all the other provisions in the bill," he said.

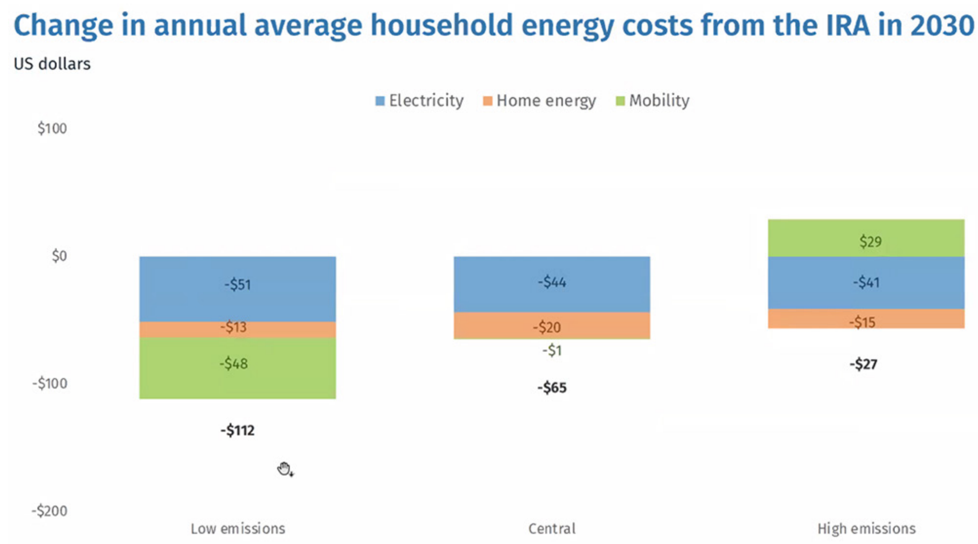
EI's estimate of GHG emission reductions is 37 to 41% below 2005 levels by 2030, he said. The bill would also create about 1.5 million full-time jobs by in the same time frame, which should increase the national gross domestic product by close to 1%, he said.

The IIJA Connection

John Larsen, who lead's Rhodium Group's energy system and climate policy research, acknowledged that IRA contains many provisions that would help households fully electrify their homes or use the bill's other tax credits for much bigger energy savings than the firms' more modest estimates.

Rhodium's analysis represents "what happens on an aggregate basis from all provisions," he said in an email to *RTO Insider*. But, in a separate research note, Larsen also says that the IRA reductions are just one part of other factors —"improving energy market conditions and technology deployment driven by current policy" that Rhodium anticipates will drive down home energy costs by $730 to $1,135 per year.

Similar to RFF, Rhodium's analysis of the IRA includes scenarios based on oil and gas prices



Rhodium Group estimates the IRA will produce modest home energy bill savings for the average American household. | *© RTO Insider LLC*

and associated emissions. Thus, higher oil and gas prices produce a lower estimate of emission reductions, while lower prices could drive higher emission reductions.

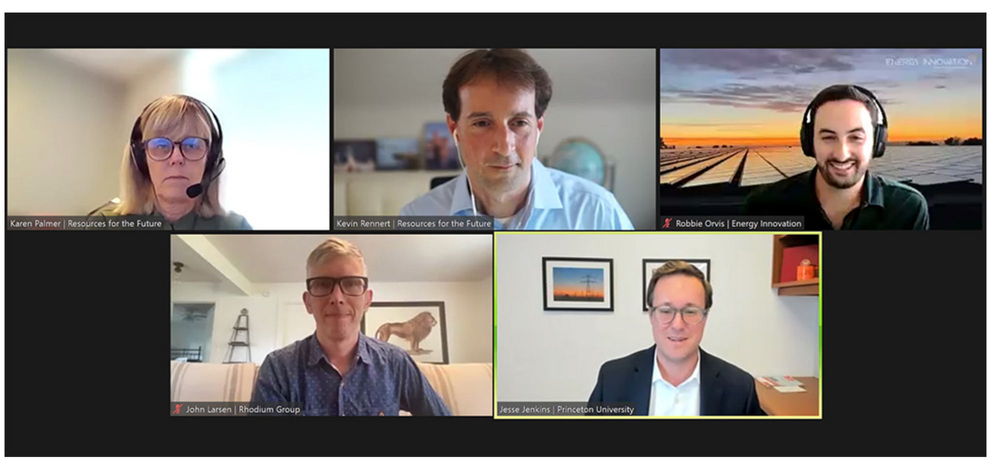
With three scenarios — low, middle and high emissions — Rhodium is projecting the IRA will cut emissions 31 to 42% by 2030 compared to a 24 to 35% base case using existing policies, including the Infrastructure Investment and Jobs Act.

Larsen expects that the IRA will provide added market momentum to IIJA's funds for the development of emerging technologies like carbon capture and green hydrogen. (See *What's in the Inflation Reduction Act, Part 2*.)

"The two bills are going to interact in a really important, powerful way," he said.

"What the IIJA did was start that first level of deployment — demonstration projects, first commercial-scale [projects] — but there's nothing after that to keep pulling that technology into the market. ... We see the [difference] between a conventional hydrogen price and clean hydrogen getting closed in some instances because of the IRA tax credit provisions."

Still, because of its "nascent nature," Larsen does not expect green hydrogen to "contribute meaningfully to total GHG reductions through 2030; [the IRA] gets that technology to scale so it's ready to go for the next wave," he said. ■



(Clockwise from top left) Moderator Karen Palmer, Resources for the Future; Kevin Rennert, RFF; Robbie Orvis, Energy Innovation; John Larsen, Rhodium Group; and Jesse Jenkins, Princeton ZERO Lab. | *Resources for the Future*

FERC/Federal News

DOE Launches $675M Program to Build Critical Mineral Supply Chain

RFI Shows Major Focus on Mining and Extraction Research and Pilot Projects

By K Kaufmann

The U.S. Department of Energy is consolidating its portfolio of critical mineral research and development programs in a bid to build a domestic supply chain of materials needed to decarbonize the national economy.

The new, wide-ranging Critical Materials Research, Development, Demonstration and Commercialization Application (RDD&CA) program will be funded with $675 million from the Infrastructure Investment and Jobs Act (IIJA).

In a *request for information* released Aug. 9, DOE said the program with the tongue-twisting abbreviation would "integrate, expand and accelerate DOE's strategy to build resilient, diverse, sustainable and secure domestic supply chains that support the clean energy transition and decarbonize energy, industrial, manufacturing and transportation sectors while promoting safe, sustainable, economic and environmentally just solutions to meet current and future needs."

According to the RFI, the RDD&CA program was authorized in the Energy Act of 2020, the bipartisan package passed in December of that year. The funding in the IIJA includes $600 million to be used over four years to promote critical materials recycling, innovation, efficiency and alternatives. Another $75 million will provide two years of funding for the development of a Critical Material Supply Chain Research Facility, also authorized by the Energy Act.

The projects using this combined funding will "make our nation more secure by increasing our ability to source, process and manufacture critical materials right here at home," Energy Secretary Jennifer Granholm said in a *press release* announcing the RFI. "The [IIJA] is supporting DOE's effort to invest in the building blocks of clean energy technologies, which will revitalize America's manufacturing leadership."

U.S. dependence on China and other foreign sources for the critical minerals needed for a range of clean technologies — for example, the lithium-ion batteries used in electric vehicles — has long been an easy target for Republican critics of President Biden's clean energy goals. According to DOE, global demand for critical materials in general could grow by 400 to 600% over the next several decades, while demand for lithium and graphite, also used in EV batteries, could increase by as much as 4,000%.

China controls up to 80% of lithium refining capacity and 60% of battery component manufacturing, according to *figures* from BloombergNEF.

The need for building out a domestic supply chain for these critical materials has also provided an opportunity for bipartisan agreement — such as the funding for the RDD&CA in the IIJA.

An additional $140 million in the law is being used to support the development of "a new facility to demonstrate the commercial feasibility of a full-scale rare earth element and critical minerals extraction and separation refinery using unconventional resources," such as coal waste and ash and acid mine drainage. An *RFI* for that project was released in February.

Critical mineral supply chains could also get a boost from advanced manufacturing credits in the Inflation Reduction Act, passed by the Senate on Sunday and now awaiting a vote in the House of Representatives. Battery cells and modules are eligible for credits of $10 to $35 per kWh of capacity, and a range of critical minerals will be able to take a 10% tax credit on their production costs.

Lithium mine | *Shutterstock*

FERC/Federal News

In 5 Years

The DOE defines critical materials "based on [their] importance to a range of energy technologies and the potential for supply risk," the RFI says.

The Critical Material RDD&CA will take a "material-by-material approach," prioritizing the following minerals:

- neodymium, praseodymium and dysprosium, used for magnets in wind turbines and electric and fuel cell vehicle motors;
- lithium, cobalt, nickel, graphite and manganese, used for lithium-based batteries needed for energy storage;
- platinum group metals used for catalytic converters in fuel cells and in electrolyzers for green hydrogen production;
- gallium, used for light emitting diodes and wide bandgap power electronics in high voltage power generation;
- germanium, used for microchips needed for sensors, data and control in smart manufacturing.

The new initiative will also be based on DOE's core "pillars" for supply chain buildout, which include diversifying and expanding domestic critical mineral supplies, developing substitutes and promoting efficiency across the supply chain, as well as a circular economy approach to repair, reuse, recycling and remanufacturing.

The RFI lays out tentative program priorities for each of the critical mineral groups. For example, DOE envisions a range of research and development activities, pilots and demonstration projects for all aspects of the supply chain for neodymium, praseodymium and dysprosium, from mining and processing to recycling. A tighter focus is used for lithium, cobalt and other key battery minerals, with R&D and pilots planned only for mining, extraction and coproduction, in which multiple materials are produced together and bring in similar revenue streams.

DOE is looking for input and ideas on how best to organize and execute the program, with comments due by Sept. 9. The RFI includes a range of questions, from what criteria should be used to measure program success, to concerns about "the ideal timing and desirable features, terms and conditions of off-take agreements that would stimulate the private sector investment necessary" to achieve program goals.

Questions also focus on community benefits and engagement, including job creation, labor standards and workforce training, especially in disadvantaged and low-income communities.

How long it will take to develop a domestic supply chain for critical minerals is also a core concern. "What are the most high-impact opportunities to diversify supply, develop substitutes, increase material and manufacturing efficiency and drive reuse and recycle of critical materials for energy technologies … in the next 5 years?" the DOE asks. "What quantitative impact could the Critical Materials RDD&CA program have on domestic supply chains in 5 years?" ■

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FERC/Federal News

DOE Previews New Federal Funding for Energy Storage Demo Projects

By John Funk

The Biden administration's goal that the U.S. economy achieve net-zero carbon emissions by 2050 will require an investment of $300 billion a year until 2050, or $10 trillion in total, the U.S. Department of Energy estimates, including $21.5 billion to support large-scale clean energy demonstration projects.

Effectively allocating the $355 million in initial funding, authorized by last year's Infrastructure Investment and Jobs Act, is the task now facing DOE, Katrina Pielli, senior policy adviser at the department's Office of Energy Efficiency and Renewable Energy, said during a *webinar* Aug. 9 presented by the Clean Energy States Alliance with the DOE and the Sandia National Laboratories. The session drew several hundred spectators.

Experts discuss millions of dollars in new funding for energy storage pilot projects authorized by the Infrastructure Investment and Jobs Act. | *Clean Energy States Alliance*

The department is taking time to develop "front-end planning" to help the industry develop storage projects that will be able to meet congressional expectation, Pielli said, adding that it is currently estimating it will begin accepting applications later this quarter.

"We're maintaining a risk-balanced, defensible portfolio of investments. And what this means is that we will be reviewing project applications to ensure those selected for these demonstrations are viable at scale and they're replicable. We want to scale down risk so we can scale up the clean energy technology deployment," she said.

The agency will be making awards with 50-50 cost-sharing agreements, she added. "We'll take early steps to set up these demonstrations, and our industry partners will assist with the steps that lead to commercialization and deployment," she explained.

The law requires DOE to focus on rural areas with populations of less than 10,000, disadvantaged urban areas and former mining sites for potential projects.

"Congress did direct us to prioritize job creation, greenhouse gas emission reduction and the economic benefits for host communities. Here again, we're working closely with our National Labs to understand the technical, regulatory and economic challenges associated with clean energy development on mined land," Pielli said.

Dan Borneo, an engineering project leader at Sandia, said the goal is to reduce storage costs by 90% compared to the baseline cost for lithium-ion storage in 2020, to 5 cents/kWh, he said.

"For all the different storage technologies that are out there that could be used for grid storage, none of them currently meet a 5-cents/kWh levelized cost of storage. None of the technologies are there yet, which is why we need more investment and more demonstrations at scale," he said.

"We are looking at targeting technologies in that realm with easy demonstration, all the way through more mature technologies that have already been proven, but may still need to be piloted in new or new regions that have not yet seen storage."

Borneo said the lab will be funding demonstration storage programs for DOE and the Defense Department. "We're looking at reasonably small behind-the-meter systems that can prove long-duration energy storage for a specific resilience application." ■

CAISO/West News

Calif. Adopts Country's Most Ambitious OSW Target

By Robert Mullin

The mood was almost euphoric Wednesday as the California Energy Commission adopted the nation's most ambitious long-term offshore wind goals, targeting a buildout of up to 5 GW by 2030 on the way to 25 GW by 2045.

The CEC approved the targets about a week after it released an updated draft report proposing to sharply increase earlier proposed goals of 2 GW by 2030 and 10 to 15 GW by 2045, which critics — including Gov. Gavin Newsom — contended were too conservative. (See *California Boosts Offshore Wind Goals*.)

Wednesday's vote approved a final version of the *report* with the higher goals, which drew only praise from commenters at the commission's monthly business meeting. Those speakers included labor representatives, members of environmental and community groups, students, a retired U.S. Navy admiral and a former state lawmaker.

"I think I share a belief that we all have that, in the future, we will look back to this moment, as you adopt this report with its recommended goals, as a critical milestone in our efforts to combat climate change," said David Chiu, the former California assemblymember who drafted last year's *Assembly Bill 525*. The law requires the CEC to "quantify the maximum feasible capacity of offshore wind" off the state's coastline and set planning goals for 2030 and 2045.

"This is a momentous day," said Commissioner Kourtney Vaccaro, the lead commissioner for the state's offshore wind efforts. "I'm really excited. I wholeheartedly support approval of this report. And I am all in to do all of the work that needs to be done, because this is foundational. It's a milestone."

CEC Chair David Hochschild — who opened Wednesday's meeting by lauding the "amazing event" Aug. 7 when the U.S. Senate passed the Inflation Reduction Act (IRA) — said the adoption of the offshore wind goals was part of a "trifecta year for us" that will include the signing of the IRA and this fall's first California OSW lease auction by the U.S. Bureau of Ocean Energy Management (BOEM). (See *Senate Passes Inflation Reduction Act*.)

BOEM this spring issued a *proposed sale notice* for five lease areas off the California coast, with auctions expected this fall for the Humboldt Bay and Morro Bay areas.

Commission Vice Chair Siva Gunda pointed to two key technical benefits that offshore wind will provide to a California grid increasingly reliant on intermittent solar resources.

"One is the load shaping it offers and the capacity factor that it offers, which is incredibly important for balancing the grid, but also in our opportunity to retire fossil assets as quickly as we can," Gunda said. "So I think it's an important element of the overall piece, and diversity [of resources] is critical."

"This is one of the big pieces of clean, kind of firm power in a way," Commissioner Andrew McAllister said. "Not quite in the sort of traditional definition, but it's a great constant resource that's predictable, and so it is a big piece of the puzzle that's actually taking shape."

Reshaping Communities

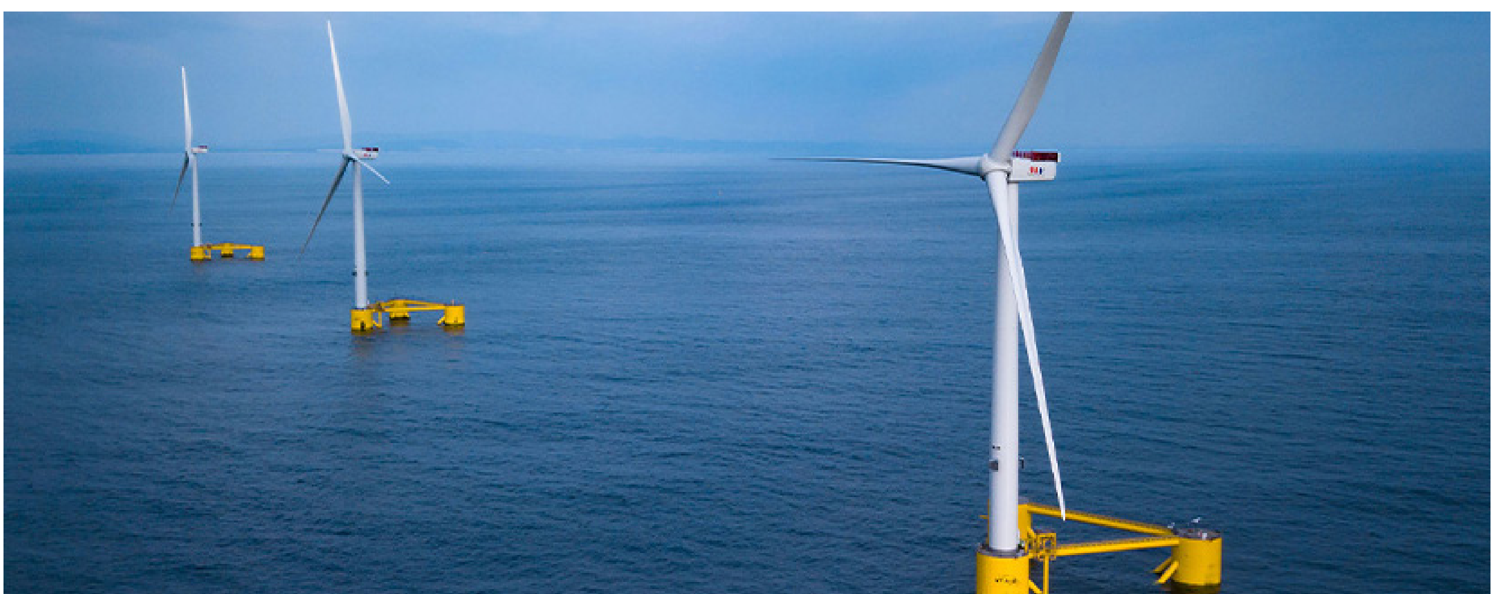
McAllister also pointed to the potentially transformative impact of a growing offshore wind industry on California's economy, especially in struggling coastal communities.

"If you just envision what that is going to look like, in practical terms, for our economy, for our workforce ... this is just a huge, huge endeavor that's going to have all sorts of benefits for the state, and it's going to reshape communities," he said.

The economic and employment impact of offshore wind was a recurring theme in public comments during Wednesday's meeting.

"When we first proposed AB 525, I said that we had already seen a preview of the future havoc that climate change will wreak in the form of heat waves, wildfires, droughts [and] rolling blackouts, and that we have a once-in-a-generation opportunity to transition to a new clean and green society in a way that could put thousands of Californians into high-skilled, well paying jobs," said Chiu, currently the city attorney for San Francisco.

"We're really impressed with the progress that the state is making towards offshore wind, not just for its impact on the transition to clean



California will rely on floating turbines like those already being used in areas off the coast of Europe. | *Principle Power*

CAISO/West News

energy, but for its impact to labor," said Larissa Petrucci, a research analyst with joint labor-management group NorCal Construction Industry Compliance. "As we move to a clean energy economy, we really want to see those skilled and trained workers build the machines that will move us to 100% clean energy. We want jobs that we can be proud of, and this is exactly what the offshore wind energy will provide."

And while the CEC calls for 3 to 5 GW of floating offshore wind by 2030, Petrucci and other labor representatives called for the state to aim for the higher end of that range.

Speaking for the California State Building and Construction Trades Council, Mark Mulliner said the Humboldt area is a "desolate place" after the loss of jobs stemming from the closure of lumber mills.

"The best opportunity is what you guys are looking at approving," Mulliner said, adding that the OSW industry will be a "huge part of changing the environment and changing the work environment for Humboldt and for the local communities."

Trevor Zierhut, of LiUNA Local 585 in Ventura County, said the state is "facing a unique opportunity with determined stakeholders all working towards a common goal and the federal government actually moving forward at an unprecedented pace on this issue."

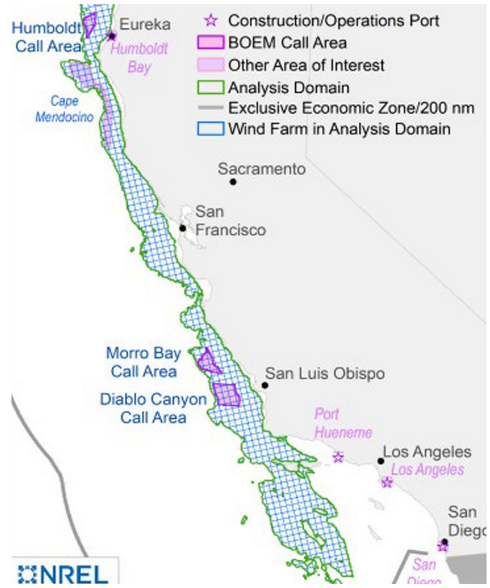
But he cautioned that state officials should not neglect the need for new transmission to handle OSW output.

"If we aren't planning big on transmission, we're only doing half the work necessary to make the changes we all want to see," Zierhut said.

Retired Adm. Dennis McGinn posed the state's OSW efforts as a way to shore up the nation's energy, economic and environmental security and quality of life. "California has the opportunity to seize this wonderful asset offshore as former [Assemblymember] Chiu outlined, and it is there for the taking."

McGinn added that, as the former commander of the U.S. Third Fleet involved in operations off the California coast, "it is compatible to have military operations in training and offshore wind, producing great clean energy in a complimentary way."

University of California, Merced student Cassandra Boyce delivered an emotional plea encouraging state officials to "go big" with offshore wind.



NREL has identified five promising areas for wind development off the coast of California. | *NREL*

"We're facing a climate crisis, and the only way we can solve it is to stop burning fossil fuels. I know that the goal of [over] 20 GW by 2045 is really going to support that movement towards a future that won't just be clean, but healthy," Boyce said. ■

CAISO/West News

Hearing Shows Solar Conflict in Sun-soaked Eastern Wash.

By John Stang

A proposed massive solar farm is stirring controversy in southeastern Washington, pitting farmers and unions against local officials and the region's Republican Party, while another similar project looms on the horizon.

Both projects are in the northwest corner of Benton County, just a few miles from four similar solar projects in neighboring Yakima County. All six are proposed for the same chunk of desert-like steppe habitat in the Yakima River Valley that crosses the line between the two counties.

Benton County is home to the highly contaminated Hanford Nuclear Reservation, which is surrounded by pristine buffer zones, including Rattlesnake Ridge along the site's western borders. The two Benton County solar farms are to be located west and southwest of the ridge on private farming and grazing areas.

On Aug. 8, Washington's Energy Facility Site Evaluation Council (EFSEC) held a public hearing in Pasco on a proposal by Innergex Renewable Energy to build the 470-MW Wautoma Solar Project just east of the Benton County line.

In Washington, an energy project developer has the choice of getting project approval from the state through EFSEC or from the host county. Innergex opted to go through EFSEC.

Last week's hearing turned out support from farmers in the immediate area and construction unions, and opposition from Benton County's government and Republican Party.

Québec-based Innergex is seeking to build the Wautoma project on 3,000 acres of sagebrush, of which less than 1% is being farmed. The project, which would include batteries capable of storing power for four hours, would be sited next to a major transmission line and is 30 to 40 miles from the nearest towns and cities.

Laura O'Neill, Innergex senior environmental coordinator, said farm owners in the area are interested in the project and that the proposed site avoids environmentally sensitive lands. Western Hanford and the area west of the reservation are home to hundreds of elk, and the project's fence would include openings for large animals to pass through.

Construction is scheduled to begin in the first quarter of 2024 and be completed by the third quarter of 2025. O'Neill said the project's

Innergex wants to build its solar farm on 3,000 acres of sagebrush in Washington's Benton County. | *HikeTriCities.com*

timetable and size could easily change during the design phase.

'Visual Pollution'

During last week's hearing, three members of the Robert family, which owns the 3,000 acres of primarily grazing land, lobbied EFSEC to support the Innergex proposal. Maya Robert said agricultural economics has been adversely affecting their ranching. "Solar power will help us make productive use of unproductive land," she said.

Her uncle Robin Robert said roughly 800 sheep can share the land with the solar farm, with the animals using the panels for shade, making the project the Washington's third proposal to develop agrivoltaics, the simultaneous use of solar panels with grazing or farming.

Stan Isley, representing the Yakima Valley Audubon Society, gave conditional support to the proposal, saying the developers must be careful of potential harmful effects to the wildlife and environment in that region. Brendan Mercer, a neighboring grower of wine grapes, wanted to make sure the proposal's effects on well water are studied and voiced concern about the impact of intense sunlight reflecting off panels on light-sensitive grapes.

"This proposal creates jobs and helps farmers. This is a very remote area," said Stan Gasper, a Benton County resident. Four union leaders and members supported the project because its construction would employ hundreds, although only three to five permanent staff members would be needed after construction.

A woman representing the Benton County Republican Party opposed the project. "If you see a bunch of windmills and a bunch of solar panels, that's visual pollution," she said. There is an unrelated major wind and solar project several miles to the southeast within sight of the heavily populated Tri-Cities, which has sparked opposition because many residents don't want to look at the wind turbines on their landscape.

Benton County resident George Penn opposed the Innergex project for visual reasons, arguing solar panels should be set up solely on the Hanford site, which is partially off-limits to the public. Area resident Lorre Gettre said farmers don't always know the consequences of putting solar farms on their lands and voiced fears about the storage batteries leaking.

The Innergex site is on land zoned for agriculture. Last December, the Benton County Board of Commissioners — which vehemently opposes the wind and solar project south

CAISO/West News

of the Tri-Cities — passed a law prohibiting large solar projects on agricultural lands. But Innergex argued last week that the project is still consistent with Benton County's comprehensive growth management plan.

Other Projects Loom

Meanwhile, a second solar farm is now in play for western Benton County.

Florida-based renewable energy company BrightNight confirmed to *RTO Insider* on Aug. 8 that it plans to build a 500-MW solar farm just south of Rattlesnake Ridge.

The Hop Hill Solar project would be built on 17 square miles of cattle- and sheep-grazing land with the panels to cover about 30% of the site. The rest will be kept as grazing land, including the shady areas beneath the panels located eight to 10 feet above the ground, said Meribeth Sawchuk, BrightNight vice president of communications. While BrightNight has several projects on the drawing board across the nation, it has not yet completed any, she said.

No timetable has been set for the project. Unlike Innergex, BrightNight has chosen to skip EFSEC and work directly with the Benton County government. Swachuk said residents tend to be cautious about allowing solar farms on lands in their home counties. "It made more sense for us to coordinate with the county," she said.

All this is taking place as the Board of Yakima County Commissioners is considering whether to declare a moratorium on approving new solar farms as they examine the long-term impacts of this blossoming industry in the region.

Three of the four solar projects proposed for Yakima County are taking the EFSEC approval route, including two 80-MW solar farms by North Carolina-based Cypress Creek Renewables — High Top and Ostria — near the county's eastern border.

EFSEC is also considering whether it will approve at the 80-MW Goose Prairie solar farm by Seattle-based OneEnergy, while Yakima County is considering approval of the nearby 94-MW Black Rock project by California-based BayWa r.e. (See *'Strength of Sunshine' Brings Solar Projects to Wash. County*.) ■

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CAISO/West News

Diablo Canyon Extension Effort Gears up

California's Last Nuclear Plant may be Needed in Switch to 100% Clean Energy

By Hudson Sangree

The movement to keep California's last nuclear plant operating beyond its impending retirement has gained new momentum with the prospect of billions of dollars in state and federal funding, support from Gov. Gavin Newsom, and the clearest indication yet that plant owner Pacific Gas and Electric could go along with the plan.

PG&E has been planning to shut down its 2.2-GW Diablo Canyon nuclear power plant by 2025, a move sought by anti-nuclear activists concerned with seismic safety and by PG&E, largely for economic reasons. In 2016, the state's largest utility signed an agreement with environmental, labor and anti-nuclear groups to close the plant on California's Central Coast rather than invest billions of dollars in environmental and safety upgrades.

Now, however, proponents see the continued operation of Diablo Canyon — the state's largest generator producing about 8.5% of total capacity — as vital to ensuring grid reliability during the state's transition to 100% clean energy by 2045. Energy emergencies during the past two summers and the likelihood of continued shortfalls caused by wildfires, drought and extreme heat have prompted some who supported the closure to reconsider, including the governor.

Newsom's office circulated draft legislation Thursday that would lend PG&E up to $1.4 billion in a forgivable loan to keep Diablo Canyon open for an additional five to 10 years beyond its planned retirement date.

"It is a very difficult decision, and it's a last resort," Ana Matosantos, Newsom's cabinet secretary, said in a workshop Friday hosted by the California Energy Commission and CAISO. Supply-and-demand forecasts based on historical data "are not necessarily reflecting our real-term reality and the speed at which the impacts of climate change are being experienced by our people and by our energy system," she said.

In extreme scenarios, cumulative disruptions from weather and fire could leave the state 7,000 MW short this summer and up to 10,000 MW short by 2025, CEC analysts said in May. The gap could be as little as 1,700 MW this summer and 1,800 MW in 2025 without cumulative crises, they said. (See *Heat, Fire and Supply Chain Woes Threaten Calif. Reliability*.)

In addition, peak summer demand has shifted later in the day, after solar ramps down on hot evenings, resulting in shortfalls, and demand is expected to increase as millions of electrical vehicles replace gas-powered cars and trucks in coming years.

"The net of all of these pieces is that we are behind where we need to be in bringing our clean resources online to ensure that we can retire these [other] resources," Matosantos said. "And so, we are meeting to have the very difficult conversation around an extension [of Diablo Canyon], the terms and the conditions under which an extension would be done, and the duration of any extension to make it as short as possible."

Funding Possible

The availability of billions of dollars in federal aid could make an extension more feasible.

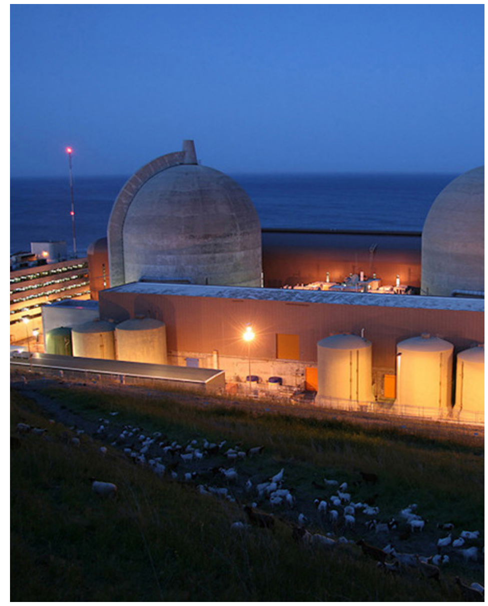
Matosantos wrote to U.S. Energy Secretary Jennifer Granholm in May, asking that the Department of Energy amend its eligibility criteria for the Biden administration's $6 billion Civil Nuclear Credit Program (CNC), funded under November's Infrastructure Investment and Jobs Act. The program is meant to assist nuclear plants at risk of closure for economic reasons.

In an April *guidance*, DOE had said CNC funding is for nuclear plants that participate in competitive energy markets and do not recover more than 50% of their costs from cost-of-service ratemaking. PG&E recovers its Diablo Canyon costs from customers under rate cases approved by the California Public Utilities Commission and would not qualify for CNC funding under that interpretation.

Matosantos requested that DOE's guidance be changed to exclude the cost-of-service requirement. The department approved the change on June 30 and extended the application deadline for the first round of CNC funding to Sept. 6.

PG&E has said it will apply for the funding. Company CEO Patti Poppe said in a July 28 earnings call that the company was looking to keep Diablo Canyon open — the strongest company statement of its kind — but warned parties that the "clock is ticking" on the time needed to switch from decommissioning the plant by 2025 to operating it through 2035.

State and federal entities, including the U.S.



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

Nuclear Regulatory Commission and the California State Legislature, will need to weigh in to make that happen in an accelerated time frame.

State Sen. John Laird, who represents the district containing Diablo Canyon, said at Friday's workshop that the speed at which the plant might reverse course would contrast sharply with the effort to close the plant, which took years.

"Endless hours and millions of dollars have been used to plan for the plant's closure and coordinate with local state and regulatory bodies on the decommissioning effort," Laird said.

Questions about cost, safety and environmental impacts, including nuclear waste storage, remain unanswered, he said. Laird also questioned the potential effects of keeping the plant open on offshore wind development. Floating wind turbines off the coast near Diablo Canyon, in the planned Morro Bay wind energy area, are expected to connect to CAISO's grid using transmission lines that now serve the plant.

"I don't see a pathway to Diablo Canyon's continued operation unless each of these elements is addressed," Laird said. "No proposal can be complete without that." ■

ERCOT News

ERCOT Could Name New CEO this Week

Texas SEPAC Approves Draft Energy Plan

By Tom Kleckner

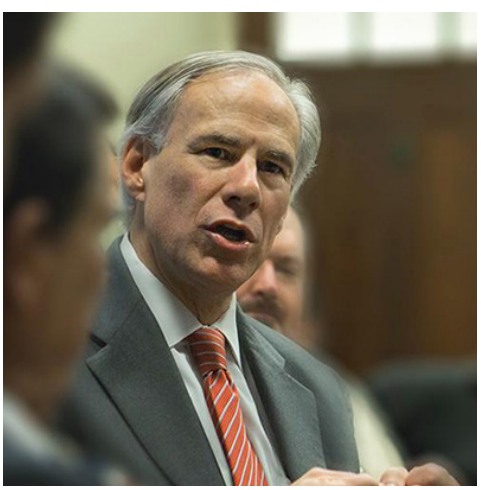
The ERCOT Board of Directors could finally unveil its choice to lead the Texas grid operator in its continued recovery from last year's winter disaster.

The Texas Public Utility Commission has posted an *open meeting notice*, as it is required to do whenever two or more commissioners meet together, in advance of today's board meeting. The notice indicates the commission will "receive information, and may give information and participate in discussion … and possible action regarding ERCOT CEO selection and ERCOT CEO compensation."

However, according to a *well sourced article* last week by *The Texas Tribune*, it is Texas Gov. Greg Abbott who wields the power to choose ERCOT's next CEO. The *Tribune* reported that the governor, who is locked in a close re-election campaign with Beto O'Rourke and appealing to his base through a heavy reliance on Twitter, has nixed a search committee's preferred finalist, former CAISO CEO Steve Berberich, and has unsuccessfully urged Phil Wilson, CEO of Lower Colorado River Authority, to take the position instead.

Berberich has been painted as a No. 1 draft pick because of his ISO and information technology experience. A Texan, he served as TXU Energy's IT vice president before joining CAISO in 2005. He retired from the California grid operator in 2020 and currently lives in McKinney, Texas, according to his LinkedIn profile. (See *CAISO CEO Steve Berberich Retiring*.)

From left: CAISO's Steve Berberich during a 2017 panel discussion with ERCOT's Bill Magness and NYISO's Brad Jones. | *© RTO Insider LLC*



Texas Gov. Greg Abbott is said to be exerting unusual control over ERCOT. | *Twitter*

Those close to the search told the *Tribune* the only reasons they were given for Abbott's veto is because Berberich's last job was in California. Attendees at SPP's Markets+ development session last week in Portland, Ore., expressed surprise when the story broke; Berberich had a reputation for speaking colorfully and directly, as he did toward the end of his tenure when he warned of California's reliability problems.

Berberich apparently had strong support from the market and ERCOT's board. The directors met in an urgent conference call July 29 that turned into a long executive session. They adjourned the call without voting on any matters.

If no announcement comes this week, it may have to wait until the board meets again in October. That would be perilously close to winter and its potential for more extreme weather. That is also about the time the PUC is expected to take up the second phase of its market design.

Alison Silverstein, an Austin-based energy consultant with regulatory experience at both FERC and the PUC, told *RTO Insider* she was "appalled" by Abbott's move, which has not been denied. She said her criteria for picking ERCOT's next CEO would be "someone with proven experience in running the grid."

"I don't care if the [next CEO] is from California or one of ours," Silverstein said. "I want the best possible person with rock-solid reliability and policy experience and management experience, because the safety of all Texans is the most important factor. Can this person run ERCOT to move us all to a better place in terms of grid reliability?"

Beth Garza, a senior fellow with public policy research firm R Street Institute and ERCOT's Independent Market Monitor from 2014 to 2019, pointed to ERCOT's statutory status as the "independent organization" responsible for managing the grid.

"There's a reason for that," she said Friday. "Most people would say that's independent

Beth Garza, R Street | *© RTO Insider LLC*

ERCOT News

from the market participants and the industry. The other part of that independence is you want an organization that is focused on the best and most appropriate technological ways to deal with whatever the problems are."

And so Brad Jones, who was appointed as ERCOT's interim CEO in the wake of the February 2021 winter storm that almost collapsed the Texas grid, is left cooling his heels. What was supposed to be a three-month temporary assignment has now turned into a 15-month gig. Jones has consistently said he doesn't want the job on a fulltime basis; he said in April that he planned to leave ERCOT in June. (See "Jones: Will Stay as Interim CEO," *Overheard at GCPA's 2022 Spring Conference*.)

"I want to ensure they get the right person into this role," he said during the Gulf Coast Power Association's Spring Conference.

It is now August, and Jones is still waiting.

According to the *Tribune* and confirmed by ERCOT staff, the PUC, with its Abbott-appointed commissioners, reviews and approves every piece of communications before the grid operator releases it. "ERCOT does not speak for Gov. Abbott on what, if any, involvement he's had," has been staff's response.

"The work of ERCOT is so important that I want its CEO and staff's first priority to always be the integrity of the reliability of the ERCOT power system, minute to minute, every single day," Silverstein said. "They should be able to operate our grid without having to care about the consequences of political agendas. The CEO's first job is to make all the essential decisions to protect grid reliability … to run the organization that ensure the reliability of the grid and its resilience. If the CEO has to ask permission to take actions to protect the grid, we'll lose the grid. We cannot have second guessing."

Garza agreed, saying, "Politics and power system engineering may not be the best combination."

Energy Advisory Committee OKs Report

The State Energy Plan Advisory Committee (SEPAC), referred to as a "little-known board of energy executives, oil and gas entrepreneurs and power utilities officials" by *The Dallas Morning News*, also raised consternation with industry observers last week as it held its second meeting.

The committee was created by *legislation* passed last year and charged with preparing a "comprehensive state energy plan" that evaluates barriers preventing "sound economic decisions" and the ERCOT market's structure and pricing mechanisms. The plan, due to the state legislature Sept. 1, must also look at ways to improve the grid's reliability, stability and affordability.

The committee comprises 12 members appointed by Abbott, Lt. Gov. Dan Patrick and House Speaker Dade Phelan. Chaired by LCRA's Wilson, its members include NRG Energy's Bill Barnes, Pedernales Electric Cooperative CEO Julie Caruthers Parsley and Oncor's Daniel Hall, as well as consultant Joel Mickey and Mike Greene, retired staffers from ERCOT and Energy Future Holdings, respectively.

"Conveniently, the governor chooses Phil Wilson as the chair, because he's got a large organization [behind him]," Garza said, noting SEPAC's lack of resources.

The other members come from outside the electric industry, with their lack of expertise exhibited when Patrick Jenevein — with some wind development experience at a small Chinese clean energy projects company (Tang Wind Energy) but primarily focused on natural gas — suggested that coal is a renewable resource, *according* to energy consultant Doug Lewin.

Lewin was among public onlookers during Wednesday's meeting, when SEPAC approved a draft of its report 7-5. At least one committee member voted against the draft because of a lack of time to review it, Lewin reported.

The report includes a recommendation that renewable resources be required to provide backup energy, despite thermal resources' well documented contribution to the days-long power outages after the winter storm. (See *FERC, NERC Release Final Texas Storm Report*.)

The report itself has not been publicly released, part of a pattern of secrecy surrounding SEPAC. Its meetings have been posted on the secretary of state's *website*, which requires sophisticated expertise with searches, but they were not livestreamed.

"I'm concerned about the legislature getting advice on something as important as electricity and natural gas policy from an organization that has met only twice and whose [members] haven't had a significant amount of time to review the material that was developed," Silverstein said, adding that its members were voting "blind."

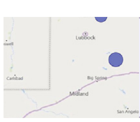
SEPAC "took a vote without the members being able to actually review the contents in detail," she said. "So, if I were in the legislature, I would use this report, whatever it will ultimately contain, as just another piece of paper. I would not attach any significant weight to it."

Garza was among several subject-matter experts who testified before the committee during its June meeting. She said at the time she thought it was a "check-the-box exercise" and would amount to little. However, Garza said she found the discussion to be "very valuable" and found herself wishing the PUC "would put themselves in a position to hear that kind of input and discourse."

"There'll be a report that goes to the legislature. I have every confidence it's a report and will be written and given to the legislature," she said. "What will it contain? Will the contents of that report be meaningfully developed with debate back and forth? No. They took input during one meeting and a second meeting to look at the document.

"You can't just say, 'I like a policy; let's do it without doing an extraordinarily detailed analysis,'" Silverstein said. "It is my hope that the legislature will not jump too quickly to adopt any superficially appealing policy path, but rather rely on the kind of research and analysis on implications and alternatives that can truly give us reliability and affordability and resilience, rather than to catchy headlines." ■

South news from our other channels



NERC, Texas RE Examine Wind Turbine Inverter Issues

ERO Insider

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

ISO-NE News

NRDC: Early Worries About ISO-NE's Capacity Accreditation Approach

By Sam Mintz

The Natural Resources Defense Council is urging ISO-NE to ensure that thermal resources get the same scrutiny as renewables, as the grid operator develops a new approach to capacity accreditation.

The environmental group has commissioned GE Energy Consulting to put together a full analysis of the options facing stakeholders and ISO-NE, but in the interim, it offered some early thoughts to the NEPOOL Markets Committee last week.

In a presentation, NRDC's Bruce Ho and consultant Nick Pappas said that ISO-NE's *preferred method* of measuring marginal reliability impact (MRI) risks under-valuing some components of clean energy resources' contributions to reliability.

"Declining marginal value does not imply existing resources [are] no longer needed for reliability, [but] solely that additional resources of similar class provide less marginal benefit," NRDC said in its presentation.

Ho and Pappas gave the example of a battery resource, developed in 2028 with an initial MRI of 90%. Under the average accreditation approach, which measures reliability contributions based on their share of their class's (in this case, batteries) total reliability contribution, the MRI declines to 41% over a 15-year period.

Using marginal accreditation, which sets a resource's accredited capacity based on the MRI of an incremental change in size, the MRI drops to 13%.

A Nexamp solar-plus-storage project in Massachusetts | *Nexamp*

"Marginal accreditation omits about one-third of the resource's total lifetime reliability contributions from a capacity awards standpoint," NRDC said. "How does this omission impact policymaker and market participant incentives for clean energy investment?"

Later on, the presentation answered its own question: "If clean energy resources' reliability values are undercompensated, ISO-NE [is] likely to see the development of sub-optimal resource mix."

NRDC is planning to put forward the results of the GE analysis at the MC's September meeting.

Other MC Business

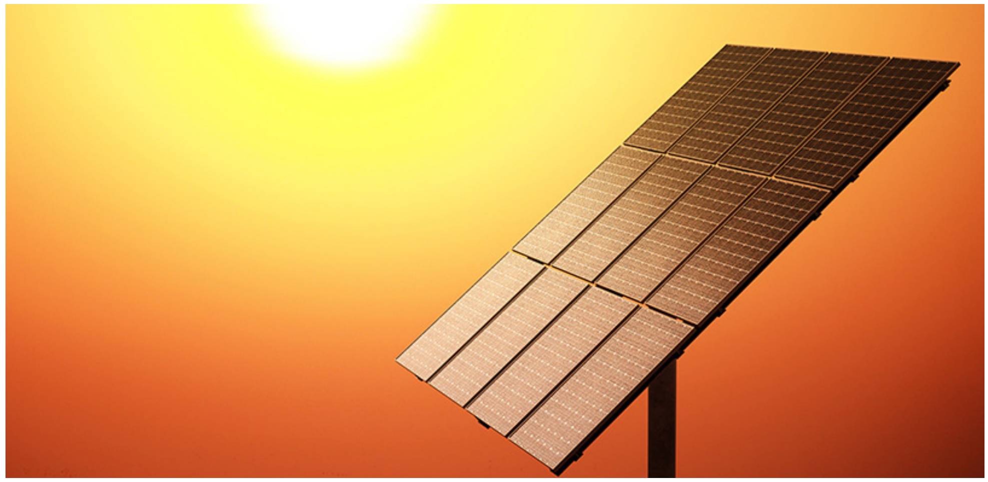
In the second day of its two-day meeting, the committee also discussed:

- *proposed changes* to the Generation Information System to sort and transfer screen enhancements, and an effort to accommodate hourly tracking;
- *modifications* to the schedule for Forward Capacity Auction 18;
- *proposed revisions* to enable do-not-exceed dispatch requirements for solar assets;
- *proposed revisions* to clarify the calculation inputs to the capacity transfer right values for pool-planned units in the Forward Capacity Market settlement; and
- *proposed revisions* to address the limited participation of storage-as-transmission-only assets in markets, including real-time energy market obligations, and metering requirements associated with storage operated as a transmission asset. ■

ISO-NE News

New England's Reliability During Heat Wave Came with Emissions Spike

By Sam Mintz



Shutterstock

A huge bump in emissions, fueled by generating facilities burning through 6 million gallons of oil, was the price that New England had to pay for making it through last month's heat wave without any significant grid reliability problems.

New data released by ISO-NE on Wednesday gave the latest illustration of the uncomfortable tradeoffs that the region faces when the weather causes high demand for electricity.

The six straight days of above-average heat was the longest such stretch in New England over recent years. Those days were responsible for much of a spike in oil consumption by power generators, which ISO-NE noted took place July 12-25.

Generators used about 6 million gallons of oil, with oil-fired generation accounting for up to 11% of the electricity produced in New England during some hours of the hottest days in that stretch.

Firing up those oil plants brought with it a huge jump in emissions: During the week of the heat wave, New England power plants emitted 845,967 metric tons of CO_2, roughly 50% more than the same period last year and 17% more than a record-setting heat wave in 2021.

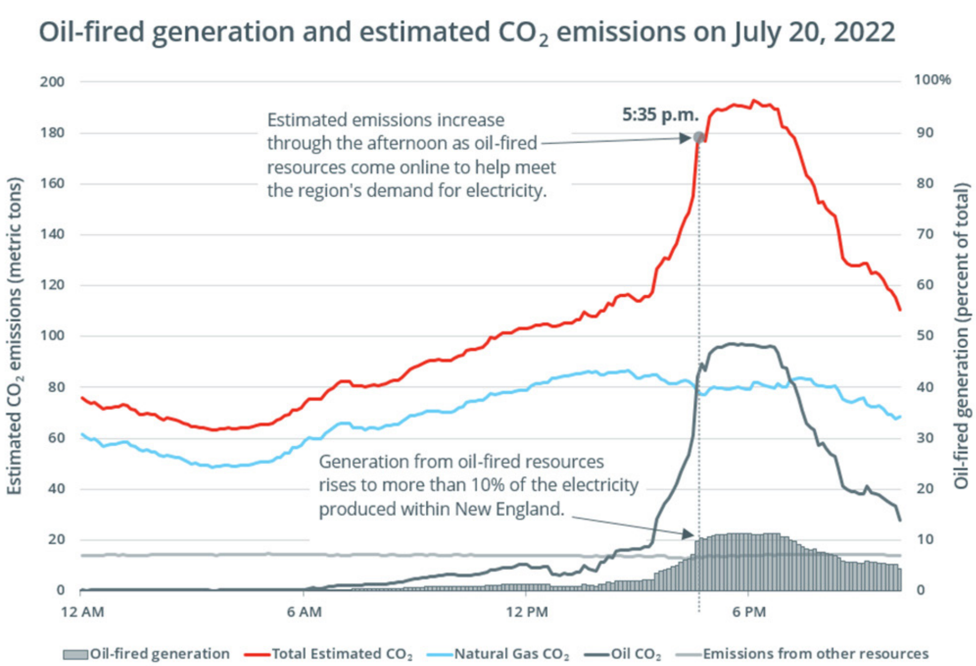
But the addition of oil generation did its job to steady the grid, and even with some unplanned outages, ISO-NE only had to issue an MLCC/2 alert, which lets resources know to hold off on testing or maintenance that might dent their availability.

"Our Operations staff managed the grid through teamwork, precise forecasting and rigorous planning, helping to ensure New Englanders had the electricity they rely on for their comfort, health and safety," ISO-NE COO Vamsi Chadalavada said in a statement.

ISO-NE said that behind-the-meter solar production played a role in ramping down demand during the brightest daylight hours of the heat wave.

"On July 19, BTM PV generation reduced system demand by roughly 4,000 MW," the grid operator said. "Without contributions from BTM PV, system demand would have approached levels forecast for weather much hotter and more humid than average."

Where solar slowed down was where oil came in, during the late afternoon and evening hours ■



Generators burn more oil and, therefore, produce more emissions, when demand is high on New England's grid. | *ISO-NE*

MISO News

DC Circuit Sends FERC Back to Drawing Board on MISO ROE

By Michael Brooks

The long-running saga of the battle over MISO transmission owners' return on equity continued last week when the D.C. Circuit Court of Appeals vacated FERC's 2020 order setting the rate at 10.02% (*16-1325*).

FERC must yet again determine what the just and reasonable ROE is in a case that has gone on for nearly a decade, with seven different commission chairs and three different presidential administrations (EL14-12, *et al.*).

In its ruling released Aug. 9, the D.C. Circuit helpfully included a two-page-long chart (p.13-14) to show the three ROE figures FERC had set since November 2013, when MISO transmission customers complained that the then 12.38% rate was too high: 10.32% in 2016, 9.88% in 2019 and 10.02% in 2020. The fluctuating figures owed to the commission repeatedly changing the inputs for the complex formula that determines the ROE.

To get the latest figure, FERC used three different financial models — discounted cash flow (DCF), capital asset pricing (CAPM) and risk premium (RPM) — to determine a zone of reasonableness and set the ROE at its midpoint. (See *FERC Ups MISO TO ROE, Reverses Stance on Models*.) That reversed the commission's previous stance against using the RPM just six months before, when it set the 9.88% ROE using only DCF and CAPM.

The court determined that was an arbitrary and capricious decision. It noted that in November 2019's Opinion 569, FERC "spent several pages demonstrating the impressive extent of" the RPM's deficiencies. But later in May 2020's Opinion 569-A, "FERC changed its tune."

"FERC is, of course, entitled to change its mind," the D.C. Circuit said. "But to do so, it must provide a 'reasoned explanation' for its decision to disregard 'facts and circumstances that' justified its prior choice. Here, FERC failed to do that."

In setting ROEs for private companies, like the MISO TOs, FERC essentially estimates what their stock price would be if they were publicly traded. Using the RPM, it estimates the cost of equity using the premium that investors would expect to earn on a stock investment over the return they would expect to earn on a bond investment.

In 2019, FERC argued, among many other things, that there was no evidence that investors used the RPM to make decisions and that the model takes into consideration previous ROEs, which may have been rendered unjust and unreasonable.

But in 2020, "FERC failed to adequately explain why it no longer mattered that investors don't use this model," the court said. "Instead, it simply noted that investors expect a premium on a stock investment over a bond investment, and that investors track the returns FERC allows. Both statements are true, but neither offers a persuasive reason to think that the risk premium model as FERC applied it here offers meaningful insight into investor behavior."

FERC also failed to address the model's circularity, the court said, merely stating that "all of the models contain some circularity."

"That explanation doesn't meaningfully engage with the 'particularly direct and acute' circularity problems presented by using old rates to set new ones," the court said.

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The D.C. Circuit did, however, dismiss the majority of the petitioners' complaints about the 2020 order, including about aspects of the DCF and CAPM and that the commission should have used the median of the zone of reasonableness, rather than the midpoint. The court found that these arguments conflicted with prior legal decisions on FERC's ratemaking, but that the commission's unjustified reversal on the RPM "is alone enough to make FERC's rate orders arbitrary and capricious."

FERC Chair Richard Glick, who had lambasted the then-Republican majority over the reversal, celebrated the court's decision. "Reversing FERC on the risk premium model is a big win for consumers, helping make energy costs more affordable," he *tweeted*.

With its order vacated, "FERC still lacks a judicially validated mechanism to set electric utility ROEs," ClearView Energy Partners noted. "With the need to invest billions of dollars to upgrade the nation's transmission system looming, FERC's response will be closely watched by all stakeholders." ■

MISO News

OMS RA Summit Confronts Midwestern Supply Squeeze

By Amanda Durish Cook

OMS resource adequacy summit underway. | © RTO Insider LLC

MADISON, Wisc. — State regulatory staff and MISO executives found no easy answers to solve a burgeoning reliability crisis after converging last week for a resource adequacy summit.

The Organization of MISO States and the University of Wisconsin-Madison's Public Utility Institute hosted the Aug. 8-9 summit four months after MISO's capacity auction indicated power shortfalls in the RTO's Midwestern footprint. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

Multiple state regulators and RTO leaders agreed that all participants should be more honest and open about resource planning and the possible impacts to neighboring areas in addressing a dwindling supply of consistent generation. MISO also repeated promises to discuss adjustments to its resource adequacy construct. (See *MISO Promises Stakeholder Discussions on Capacity Auction Reform*.)

North Dakota Public Service Commission Chair Julie Fedorchak said regulators are often in the "crosshairs," balancing utility planning, corporate decarbonization goals and state legislation.

"We're going to be blamed, too," joked MISO President Clair Moeller during an address on the first day of the summit.

Moeller said he has witnessed major change over the last six to eight years on the grid. He said prior to 2016, MISO had just one maximum generation event. Since 2016, the grid has issued 41 maximum generation warnings and events, he said. Moeller said more than ever, MISO's footprint is an "ecosystem" of interdependencies between utility territories.

MISO Focuses on Reliability's Attributes

Moeller said "resilience and efficiency are often enemies," meaning entities having to "pay up for reserves." He said MISO and its stakeholders must embark on honest conversations about the generation attributes the system will need over the next few years.

"Frankly, as a community, we've been slow to that discussion," he said. Moeller told stakeholders that MISO intends to move "almost too fast" on defining essential resource attributes and to expect a similar timeline to the RTO's long-range transmission planning.

MISO has scheduled a Sept. 21 stakeholder workshop to discuss generation's attributes that benefit system performance.

Moeller said the grid operator "never wants to be in the way" of a utility's decision to retire a resource. He also said the clogged interconnection queue boils down to an issue of money.

"The problem with the queue is money, not engineering," he said. "We could connect everyone if they didn't care about money … If you're willing to sign a blank check, you can get on."

Moeller warned that baseload retirements can't be postponed indefinitely. He said a flurry of retirement deferrals can contribute to a "false sense of surplus."

"These are old plants, and they need to go. The performance of them erodes," he said. "I predict we'll be back to very low-capacity prices next year because people didn't like that medicine."

Illinois Municipal Electric Agency's Kevin Gaden said utilities retiring generation should anticipate how they will access reliability attributes when a particular plant is gone.

"That's going to be a big problem, not just in Illinois, but the entire footprint," he said. "If no one is going to own the resources, who is going to ensure that they're there?"

Utilities' long-term planning, Gaden said, usually focuses on just their service territories. He suggested they adopt a more holistic look into the nearby grid.

Michelle Bloodworth, CEO of coal lobbying group America's Power, called for an "orderly, gradual" procession of coal plant retirements. She said a complete clean energy transition is "just not there yet."

"Once those balancing resources are gone, they're gone," she said.

Alliant Energy's Jeff Ripp said his utility's resource planning repurposes its brownfield sites with renewable energy to avoid requesting a new interconnection to the system.

Xcel Energy's Farah Mandich | © RTO Insider LLC

Xcel Energy's Farah Mandich said the company is reusing its old coal plant locations because MISO's interconnection queue remains too sluggish to add the renewable energy it is contemplating.

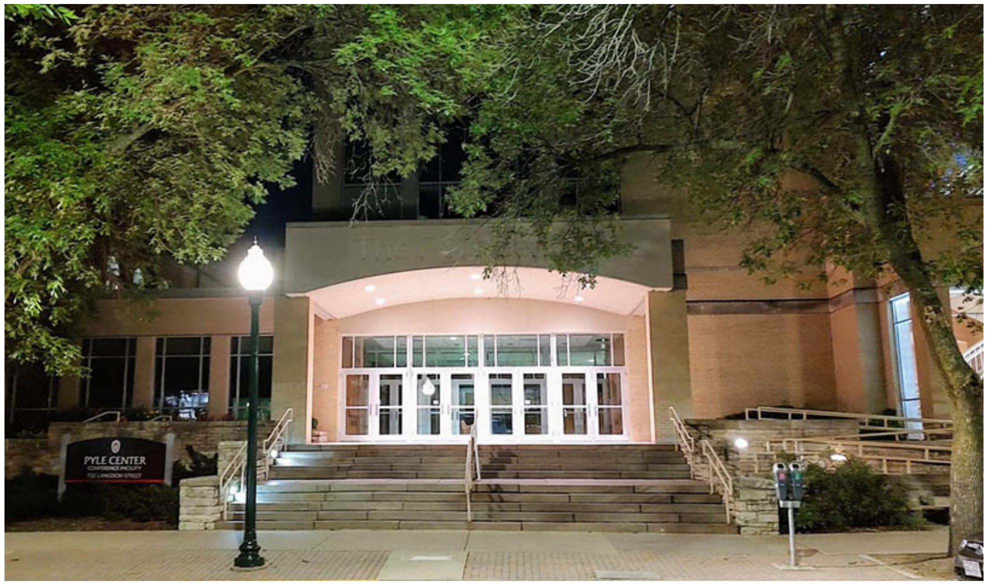
"Nobody wants customers to lose their electric service because we didn't plan well," she said.

Clean Energy's Transition

MISO Vice President of External Affairs Melissa Seymour said the solar-dominated interconnection queue worryingly contains little in the way of controllable resources.

In a separate panel, Arkansas Electric

MISO News



The resource adequacy summit was held at the University of Wisconsin-Madison's Pyle Center. | © RTO Insider LLC

Cooperative Corp.'s Andrew Lachowsky said he has "serious concerns" with solar generation's ability to replace coal resources.

"We all need to work collectively, and that's why we're in the room today," Seymour said.

She said states and utilities need to pay attention to the fleet's attributes and "look beyond" their own generation planning for the impact they may be having on other states. She also said MISO must make changes to its own resource adequacy construct.

"We need to address these real-life impacts that we're seeing and make sure we have a construct that works going forward," Seymour said.

She also said MISO is "reevaluating" whether a vertical demand curve in the capacity auction still makes sense and will initiate discussion with stakeholders in October on introducing a sloped demand curve.

"I think we can all agree that no one thought this transition would be easy," Illinois Commerce Commission Chair Carrie Zalewski said.

She said MISO's capacity auction clearing at new generation's cost, coupled with higher natural gas prices, is having a "major impact" on southern Illinois ratepayers. Zalewski said her commission is hearing about monthly bills that are about $150 higher year-over-year. However, she noted that customer bills in PJM's northern Illinois footprint are less expensive.

Sustainable FERC Project attorney Lauren Azar said she is worried that utilities and regulators will have a "sphincter" response to MISO's 2022-23 capacity auction results and return to planning for their own states in isolation.

"We're in a power pool to be able to access the resources of others," she said.

Sloped Demand Curve Likely

Michigan Public Service Commissioner Dan Scripps asked during an Aug. 9 panel whether members are happy with MISO's current resource adequacy design. After a tense silence, Ameren's Jeff Dodd joked that he needed "another Spotted Cow" — a local specialty beer — before answering.

Mandich said the RTO's resource adequacy construct needs changes to accommodate a new system, though she declined to offer specifics.

"Where we're going in the future, the old constructs won't work ... Where you have a shortage, something is broken. It's clear that what we have now is not going to serve us," she said.

"I think everyone knows that Ameren is a supporter of a sloped demand curve. That's no secret," Dodd said.

Dodd said while MISO's capacity market design worked well in the past, it now needs a sloped demand curve, seasonal division and more realistic accreditation.

MISO Independent Market Monitor David Patton | © RTO Insider LLC

Independent Market Monitor David Patton said he would have been "shocked" five years ago to be invited to speak before regulators about using a sloped demand curve in the capacity auction.

"I think it's a symptom of how the world is changing," he said during a panel.

Patton said MISO's current vertical demand curve is flawed because it doesn't value megawatts based on their contribution to avoiding a loss-of-load event. The grid operator no longer has the "luxury" of clearing the auction at such low prices, he said. Patton added that MISO's 10% retail choice supply is "killing" the RTO, forcing about 4-5 GW of merchant generation to retire prematurely because of economics.

He said because MISO was formed with such a large capacity surplus, it has taken a while for the resource adequacy picture to "catch up" with the near-zero capacity prices. He said the current capacity shortfall has little to do with the renewable energy transition and everything to do with inefficient pricing.

"We're inviting free riders when we price capacity close to zero," Patton said, noting Missouri was a net buyer of capacity in this year's auction.

Patton also said MISO should raise its shortage pricing. He said larger payouts in shortage conditions will attract the quick-start, nimble resources that MISO needs.

"We can't just focus on fixing the capacity market; we also have to get shortage pricing up to a level that's efficient," he said.

"We're enjoying the benefits of capacity that was built under a different era," FERC economist Emma Nicholson said in summing up the discussion.

NextEra Energy's Aaron Bloom agreed that the right pricing will bring MISO the resource availability it needs.

"I cringe when I hear 'attributes' because I worry that will exclude some from the market. 'You're not tall enough to ride this ride,' right?" Bloom said. He said that with solid technology, a lot of wind and solar and a little battery storage, his utility will be able to meet MISO's system needs. ■

MISO News

MISO, SPP Identify Hotspots for Smaller Interregional Tx Projects

By Amanda Durish Cook

MISO and SPP said Friday they have numerous constrained flowgates that could become candidates for smaller, cross-border transmission projects.

The RTOs unveiled a list of their congested flowgates ripe for targeted market efficiency projects (TMEPs) during an Interregional Planning Stakeholder Advisory Committee (IPSAC) teleconference. It's the first time they have searched for TMEPs. (See *MISO, SPP Take on 2nd Interregional Planning Effort*.)

The grid operators said that based on preliminary day-ahead market data, they have "numerous" constraints that have amassed a half million dollars or more in congestion annually.

SPP's Neil Robertson said the frequently congested Neosho-Riverton flowgate on the Kansas-Missouri border was unsurprisingly "prominent" on the list of the most chronically congested permanent flowgates. With $71.6 million in market-to-market (M2M) charges since 2015, the flowgate is responsible for 20.9% of the $341.87 million in M2M settlements.

Neosho-Riverton's $27 million of congestion charges the last two years is second to the Fargo-Sheyenne flowgate in North Dakota, which racked up about $36.5 million in congestion during 2020-2021.

The rest of the six most congested flowgates each accumulated anywhere from $12 million to $19 million in congestion charges during that timeframe. Robertson said staffs "commonly" found congestion in the Dakotas and along the Arkansas-Oklahoma and Kansas-Missouri borders.

Robertson said the RTOs are using their day-ahead market congestion values in their analysis because the "nuts and bolts" of their market clearing engines differ.

MISO and SPP are trying to get the most accurate congestion data, Robertson said, because congestion data determines which flowgates could use transmission improvements and how project costs are split between the RTOs.

He said the grid operators had gathered a "preliminary sampling" of congestion values that will be refined in the coming weeks. He also said staff are considering evaluating certain temporary flowgates for TMEP solutions and that some temporary flowgates could become permanent.

Robertson said the RTOs are borrowing from the MISO-PJM TMEP playbook, which has approved three small portfolios since 2017. MISO and PJM are working on another possible set of projects.

MISO and PJM TMEPs must cost less than $20 million, completely cover installed capital cost within four years of service and be in service by the third summer peak from their approval. The projects are assessed using a shorter time horizon than interregional market efficiency projects.

"We had to start somewhere, as I like to put it … moving the conversation forward," Robertson said. He added that MISO and SPP could tweak some of the existing criteria.

He said using a $20 million cost cap, a third summer peak in-service date, and drawing on two years' worth of historical congestion to determine project needs seems to make sense for the RTOs. The thresholds will ensure that a TMEP study doesn't encroach on other, longer-term interregional planning on the MISO-SPP seam, he said.

Robertson said MISO and SPP have "vast" support to move ahead with the TMEP concept.

American Clean Power Association's Daniel Hall asked the RTOs to share whether a project candidate barely misses or slightly overshoots the project criteria. He also said while ACP is a "strong supporter" of a TMEP study, he doesn't want to see the projects become "Band-Aid solutions to more efficient and effective" projects.

Robertson said MISO and SPP are holding off on finalizing any criteria until they have a better picture of congestion data.

The RTOs don't plan on recommending a list of TMEP projects until the end of the year. They don't envision designing regional cost-allocation methods or filing with FERC for approval of a TMEP process until the first quarter of 2023.

MISO and SPP will hold another IPSAC teleconference Sept. 20. ■

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ACORE Panel Lauds MISO Tx Benefits Process

Grid Strategies' Gramlich Calls for National Consensus from FERC

By Amanda Durish Cook

An American Council on Renewable Energy (ACORE) panel last week largely agreed that MISO's current transmission benefits process could serve as a blueprint for the country.

Industry experts analyzed the RTO's business case behind its recently approved long-range transmission plan (LRTP) as FERC prepares to issue a rule on regional transmission planning and cost allocation (*RM21-17*). (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"I usually say cost allocation is the biggest barrier to long-term transmission development, and, of course, the key to cost allocation is to find transmission plans where the benefits outweigh the costs," Grid Strategies President Rob Gramlich, said. "This is really important, to measure these benefits and get it right."

Gramlich said during the Aug. 9 webinar that the country could use a standardized method for quantifying transmission benefits.

"There isn't really a standard of how to do this. Even the categories themselves differ," he said, adding it would be helpful if FERC created consensus on benefits categories and their metrics.

Gramlich said MISO has been a leader in proactive, multi-benefit planning beginning with its 2011 Multi-Value Project (MVP) portfolio — lines now delivering wind power from the Upper Midwest — and its recently approved LRTP. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

He said beyond MISO's recent success, there's a widespread absence of effective transmission planning. Regions aren't planning using scenarios or a portfolio approach, he said.

Gramlich said transmission planning has been in decline since 2013, when about 4,000 miles of 345-kV and higher lines were added.

"We did a whole lot of successful transmission planning a decade ago," he said. "But since then, unfortunately, it's been sort of going down to a trickle because of the lack of effective transmission planning. Hopefully, we're in the process of reversing that."

Gramlich called on grid operators to do "at least an initial screening" of the 12 transmission benefits FERC identified in its notice of proposed rulemaking and pursue the ones that show significant benefits.

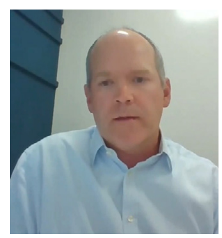
He said MISO arrived at a set of benefits that seemed to make sense for its LRTP planning. Other regions can take a similar approach to come up with different menus of benefit categories, he said.

While the LRTP benefit-cost analysis included congestion savings, resource adequacy savings and avoided risk of load shed and transmission and generation investment, it didn't include seven other benefits FERC suggested in the NOPR. MISO did include decarbonization as a benefit, something the commission hasn't called for.

The NOPR asks regions to consider the transmission benefits of avoided reliability and aging infrastructure projects, production cost savings, lower transmission energy losses, reduced chances of load shed or lowered reserve margins, diminished congestion, mitigation of extreme events and system contingencies, tempering of weather and load uncertainty, capacity cost benefits from reduced peak energy losses, deferred generation investments, access to lower cost generation, increased competition and increased market liquidity.

MISO's first LRTP portfolio is expected to deliver $37.3 billion from its defined benefits to ratepayers from 2030 to 2050. The grid operator also estimates that the plan will help facilitate the 56 GW of new renewables it anticipates adding over the next 20 years in its most conservative planning scenario.

Devin McMackin, ITC | *ACORE*



MISO's Jeremiah Doner | *ACORE*

Jeremiah Doner, MISO's director of cost allocation and competitive transmission, said it's "not an easy endeavor" to build a business case for a long-term transmission portfolio.

"There really isn't a playbook to take from," he said.

Doner said the LRTP business case has a lot of commonalities with FERC's categories. He said planners considered how much time it would take to incorporate benefit categories versus how much value they would demonstrate. For

"What we don't want to see are these 10-year lulls in between regional planning efforts because these needs are only accelerating and it'll start to get away from us if we don't keep at it."

—Devin McMackin, ITC Holdings

MISO News

example, Doner said the LRTP's savings from transmission energy losses weren't promising enough to quantify.

He said it's important to allow grid planners flexibility in what benefits they choose to quantify. He noted that MISO used different benefit metrics between its multi-value projects and its LRTP portfolio.

ITC Holdings' manager of federal affairs, Devin McMackin, said his company believes MISO's business case can be held up as a model for the nation.

"The important thing is that we can now repeat this and double down on these types of regional planning efforts, especially now that we have a climate bill that has passed Congress," he said.

McMackin said it seemed that FERC's NOPR was "taking cues" from regional planning MISO performed under its MVP and the LRTP portfolios.

"What we don't want to see are these 10-year lulls in between regional planning efforts because these needs are only accelerating and it'll start to get away from us if we don't keep at it," he said.

It makes sense for FERC to prescribe a minimum set of benefit metrics and leave some flexibility between regions, McMackin said. MISO's benefit metrics represent a good starting point for the commission to consider, he said, adding that having planners on the same page is crucial for interregional projects.

"If we want interregional planning to work, there has to be some level of common benefits basis," he said, "so not only would FERC be aiding the regional planning process, but it would also set the stage for the ability to then move forward and do some interregional planning."

Michigan Public Service Commission Chairman Dan Scripps said he considers the first set of LRTP projects as above other benefits and key to the future system's reliability. He characterized long-range planning as a shift from "reactive, near-term" reliability planning to a "forward-looking, proactive" approach to addressing reliability.

"The challenge with the value of lost load is you sort of know the value when you don't have it," Scripps said. "Winter Storm Uri was very clear evidence of that, not just in the loss of life, but also in the bills that folks saw after the fact."

Scripps said there's a risk with undervaluing transmission reliability benefits. He said the public needs a prepared system with extreme weather becoming more common and severe.

Jennifer Easler, an attorney with the Iowa Department of Justice's Office of the Consumer Advocate, said regional transmission planners should allow stakeholders access to modeling and planning assumptions early in the process so there's a broad understanding of benefit analyses.

She said MISO's set of benefits are appropriate for its backbone transmission buildout.

Gramlich said in a perfect world, all transmission benefits should be compared against all costs.

"It's almost an obvious point … You have to consider all the benefits and all of the costs," he said. "It's a little weird that we're even arguing about whether one should consider all the benefits and that we have a FERC NOPR that says, 'Yeah, here are 12 benefits but feel free to ignore a bunch of them.' That's obviously inconsistent with good public policy."

Gramlich also said it's clear that FERC's list is limited to its jurisdiction under the Federal Power Act and cannot include a full array of benefits like economic development or local emissions reduction.

"At this point, I like the FERC list of 12," he said later during the discussion. ■

NYISO News

NY Scorecard Makes Way for Utility-scale Agrivoltaics

New Scorecard System Set to Inform Upcoming Tier 1 Renewables Solicitation

By Jennifer Delony

New York's upcoming annual solicitation for large-scale renewable energy may include a new siting scorecard that would encourage solar developers to build agrivoltaic strategies into their projects.

"Proposals with co-utilization commitments will receive favorable scoring credit, and these commitments will be included in the awarded agreements," said Jeremy Wyble, senior project manager at the New York State Energy Research and Development Authority (NYSERDA).

The authority wants its expanded Smart Solar Siting *Scorecard* to "drive change" so that developers site "smarter" projects, Wyble said Aug. 9 during an American Solar Grazing Association webinar.

Comments on the proposed update to NYSERDA's 2021 scorecard were due at the end of July, and Wyble said the goal now is to review those comments and include the updated version with the next Tier 1 solicitation for large-scale renewables. Tier 1 projects are designed to help New York's load-serving entities meet the state's Renewable Energy Standard requirements and can include solar, wind, geothermal, battery, hydro and geothermal technologies.

While NYSERDA included a simplified scorecard for submissions to last year's Tier 1 solicitation, the authority used it mainly for informational purposes. This year, however, NYSERDA plans to require developers to submit the expanded 2022 version with their bids. It will "hold more weight" than it did last year, returning an actual score based on 160 total points, according to Jessica Bacher, executive director of the Land Use Law Center at Pace University. Bacher supported the authority's efforts to update the scorecard.

NYSERDA expanded its Smart Solar Siting Scorecard to help encourage certain agrivoltaic activities for solar project awards under the next large-scale renewables solicitation. | *© RTO Insider LLC*

Of the 160 points, 95 are allocated to agricultural protection, 35 to environmental protection of forested lands, 25 to community benefits and collaboration, and 5 for innovation. Developers would earn points for minimizing land impacts, which then would trigger certain strategies that are either mandatory or optional based on that land-use score.

Optional strategies would carry extra points that developers can earn by including them in their proposals to offset land-use impacts. There would be no points awarded for mandatory strategies.

The bulk of co-utilization strategies on the scorecard are optional because agrivoltaics is a new field, and it's not "appropriate" yet to mandate them within the new scorecard incentivization structure, Bacher said.

The two mandatory co-utilization strategies on the scorecard are conducting a site survey or engaging landowners or farmers to assess feasibility and land suitability for production of preferred crops or vegetation species; and engaging the farming community to determine feasibility and solicit interest in grazing activities in or around the project.

High-scoring optional strategies include:

- designing for the land's current and future farming uses;
- maintaining pollinator habitat, crop production or grazing in long-term project operations; and
- incorporating regenerative farming practices, such as plant cover crops or low tillage, for maximum carbon sequestration.

Engagement with the community is a recurring theme in the scorecard, Bacher said.

NYSERDA plans to require developers to complete the scorecard for the upcoming solicitation if they are proposing to build a solar project with a capacity of 20 MW or larger on 100 acres or more. ■

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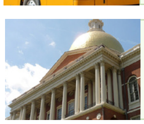

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PJM News

Illinois Climate Bill Could Force $2B in Tx Upgrades, PJM Says

Well Sited Generation Could Cut Costs

By John Norris and Rich Heidorn Jr.

VALLEY FORGE, Pa. — Illinois' climate goals could cost other states in PJM and MISO tens of millions in transmission upgrades over the next two decades as coal and natural gas power plants are forced to retire, PJM said last week.

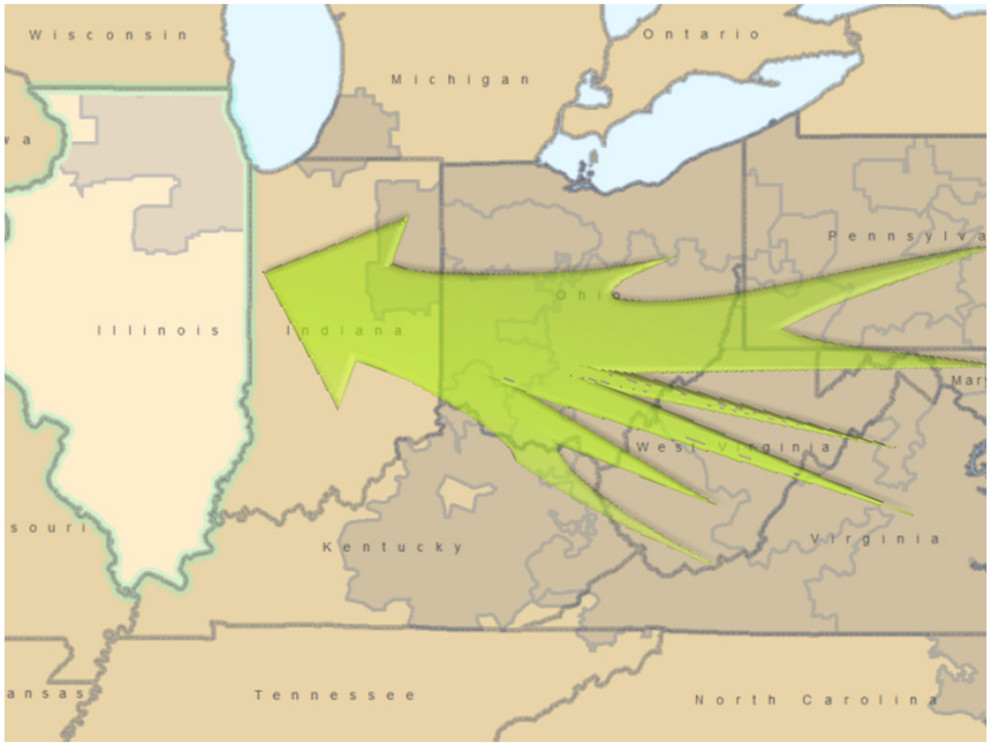
PJM's Illinois Generation Retirement *Study* found that the state's *Climate and Equitable Jobs Act* (CEJA) could require $700 million in transmission upgrades through 2030 and an additional $1.3 billion by 2045 in the Commonwealth Edison, FirstEnergy, Duquesne Light Co. and American Electric Power zones in PJM, and the Northern Indiana Public Service Co. (NIPSCO) zone in MISO.

CEJA, which Gov. J.D. Pritzker signed in September 2021, requires Illinois to eliminate carbon emissions from its electricity sector, with coal and natural gas generators shuttered or converted to zero-emission resources by 2045.

PJM predicts the retirement of almost 12,000 MW of generation by 2030 and nearly 23,000 MW by 2045. The RTO's study identified plants scheduled to retire or that are likely to retire under CEJA based on publicly available emissions data and published heat rates. The RTO said it confirmed its findings with plant operators.

It also looked at potential replacement generation based on the 200,000 MW in its interconnection queue, 95% of which is solar, wind or hybrids including renewables and storage.

David Egan, PJM | © *RTO Insider LLC*



Increased East-to-West imports resulting from the retirement of Illinois coal and natural gas plants would cause numerous, significant thermal-based reliability violations in both the 2030 and 2031-2045 scenarios, PJM says. | *PJM*

'Initial Snapshot'

PJM said the study is a "very initial snapshot" of CEJA's impact and that it is not proposing projects for the Regional Transmission Expansion Plan (RTEP) based on it.

"The cost estimates identified in this study will not actually be charged to consumers today," PJM said. "As the system evolves with retirements and additions, we will have a better sense of the necessary transmission that will be needed to alleviate any reliability violations."

PJM's David Egan, who *presented* the study results to the Planning Committee on Aug. 9, said transmission upgrade costs could be reduced if the new generation is connected in favorable locations near recently deactivated plants. But upgrades might need to be accelerated if existing generators retire earlier than modeled, he said.

Asked about the potential impact of the incentives for carbon capture in the Inflation Reduction Act, which is awaiting President Biden's signature, Egan said, "As these mandates or laws change, we will be modifying our studies." (See related story, *House Passes IRA, Sends to Biden's Desk*.)

MISO Impact

PJM said it will combine its study with an analysis MISO is expected to complete late this year or early next to determine optimized interregional projects that could cut costs.

"Our study report is emphasizing that both PJM and MISO recognize the need to collaborate on case assumptions and work together on solutions when appropriate," said PJM's Dan Lockwood.

"We anticipate MISO will identify additional impacts and costs," Egan said.

The study does not include MISO's long-range transmission plan's (LRTP) Tranche 1 projects or its additional LRTP study work in the Illinois area.

PJM focused its efforts on MISO facilities along the RTOs' seam and reviewed results with NIPSCO, the MISO transmission owner facing the biggest impact.

PJM News

AREA	2030 ($M) 69 kV	2030 ($M) 138 kV	2030 ($M) 345 kV	2030 ($M) Total	2031–2045 ($M) 69 kV	2031–2045 ($M) 138 kV	2031–2045 ($M) 345 kV	2031–2045 ($M) Total
FE	0.0	319.2	0.8	320.0	0.0	180.0	0.0	180.0
AEP	0.3	63.3	0.0	63.6	0.0	68.9	109.2	178.1
DLCO	0.0	180.0	0.0	180.0	0.0	0.0	0.0	0.0
ComEd	0.0	98.0	0.0	98.0	0.0	122.5	39.0	161.5
NIPSCO	0.0	0.0	0.0	0.0	0.0	52.8	72.6	125.4
Subtotal	0.3	660.5	0.8	661.6	0.0	424.2	220.8	645.0

COMBINED TOTAL ($M)	
PJM	PJM & MISO*
$1,181.15	$1,306.55

AREA	2030 ($M) SVCs	2030+ ($M) SVCs
ComEd	52.5	472.5
NIPSCO	19.3	173.7
Subtotal	71.8	646.2

COMBINED TOTAL ($M)
PJM & MISO*
718

Note: PJM did not study for impacts on all of MISO. Results focused on NIPSCO and PJM-MISO interfaces only.

PJM estimated $1.3 billion in transmission upgrades to address thermal violations and $718 million to fix voltage violations as a result of plant retirements forced by Illinois' Climate and Equitable Jobs Act. | *PJM*

Not Included

PJM did not attempt to estimate early retirements because of current CEJA operational limits on natural gas-fired generation. It also did not include new renewable generation expected to be added to the system under CEJA's incentives. In support of the bill, the Illinois Commerce Commission in July released its first draft of the *Renewable Energy Access Plan* (REAP) to improve transmission capacity to support increased renewables.

Costs for reliability-must-run contracts for units that PJM may ask to operate beyond their desired deactivation dates also were not included in the study.

State Impacts

"This puts Ohio in a very precarious position of having to pay for the decisions of another state," said Mike Haugh, of the Ohio Consumers' Counsel.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said he hoped the RTO would look for "opportunities to reduce these costs."

PJM encouraged stakeholders to attend their CEJA workshop on Aug. 22 to learn more about the law and how it would affect their current or future investments.

Thermal Violations

PJM also identified upgrades that would be needed to comply with the thermal, reactive, stability and short-circuit requirements of NERC standard TPL-001-4.1.

Upgrades for thermal violations are estimated at $1.3 billion (64% of the total), almost evenly split between the 2030 and 2031-2045 study periods. About 15% of the total is for ComEd.

Because not much new generation is projected for Illinois, the study predicts increased East-to-West imports will cause "numerous, significant" thermal reliability violations in both the 2030 and 2031-2045 scenarios, PJM said.

The study said 69 upgrades to PJM's 138-kV system are responsible for 82% of the thermal upgrade costs, with 16 345-kV upgrades accounting for the remainder.

Voltage Issues

Fixing voltage violations is estimated at $718 million (36%). "Unlike thermal violations, which tend to be more linearly aligned with megawatt impacts, voltage violations are nonlinear," PJM said.

Voltage instability is expected to emerge by 2030, with widespread violations expected in 2031-2045 from a lack of reactive support in the ComEd area and increased imports into Illinois to serve load.

"If not resolved with system upgrades, [the voltage stability problems] could lead to blackouts driven by voltage collapse," the report said. "This is indicative of the need for additional transmission system expansion — reinforcements to existing lines or construction of new lines — on East-West transmission paths between ComEd and AEP."

ComEd and NIPSCO proposed static volt-ampere reactive compensators to address the voltage instability concerns and synchronous condensers to replace the megavolt-amperes reactive (MVARs) capabilities lost with the plant retirements, estimating costs at $525 million and $193 million, respectively.

"Voltage issues generally need to be fixed near where" the generation is removed, said Egan.

PJM's Sami Abdulsalam said renewables' ability to provide voltage support is limited. "A megaVAR is a megaVAR once it reaches the grid," he said. But solar and wind cannot provide MVARs when they are not generating power, unless they also have storage, he said.

Impact on Individual TO Zones

PJM reported the need for the following upgrades on individual TOs:

- ComEd: $100 million through 2030 to address thermal overloads, most for a new 138-kV line from Haumesser to West Dekalb to Glidden. ComEd expects an additional $160 million in thermal upgrades after 2030.
- AEP: $63.5 million to solve thermal overloads through 2030, almost 80% to rebuild the 138-kV AltaVista-Otter-Johnson Mountain-New London line. After 2030: $178 million to solve thermal overloads, about 85% for a new 345-kV Segreto-Cook line and a rebuild of the 138-kV West End Fostoria-Woodville line.
- FirstEnergy: $320 million to address thermal violations caused by an increase in East-to-West power flow by 2030, and about 60% for reconductoring five 138-kV circuits: two between Leroy Center and Mayfield, and three from Charleroi to Union Junction, Westraver and Yukon. After 2030, FirstEnergy estimates $180 million in upgrades to address thermal violations, more than 80% to reconductor the following 138-kV lines: Mitchell-Shepler Hill Junction, Peters-Union Junction, Yukon-Smithton, Leroy Center-Mayfield and Richland-Lockwood (AEP).
- Duquesne: $180 million, most for new 138-kV facilities, including a new Elrama substation, two new ties and one new line. About 35 circuit miles of 138-kV reconductor is also needed.
- NIPSCO: $125 million in upgrades over the study periods to address thermal-based reliability criteria violations. ■

DC Circuit Faults FERC on Cost Allocation of NJ Transmission Projects

Rejects PJM 'de Minimis' Exemption from DFAX

By Rich Heidorn Jr.

FERC failed to explain why the DFAX method should be used to allocate the costs of two North Jersey transmission projects but not for a similar project in Artificial Island, the D.C. Circuit Court of Appeals ruled last week, partially supporting appeals by Consolidated Edison, the New York Power Authority and two merchant transmission operators (*15-1183*).

The court also rejected PJM's "de minimis" exemption for applying DFAX, short for "solution-based distribution-factor analysis."

But the court's Aug. 9 order rejected a related challenge by the New Jersey Board of Public Utilities, ruling that Public Service Electric and Gas customers would foot the bill for the North Jersey projects after Con Ed terminated its use of the "PSEG wheel," an agreement that allowed the utility to deliver power to New York City through PSE&G transmission.

The 43-page order addressed 13 petitions for review challenging 20 FERC orders, "involve numerous parties, implicate a series of related legal issues and arise from a complex procedural history," the court said.

Bergen-Linden, Sewaren Projects

Much of the case involves $1.3 billion in transmission upgrades authorized by PJM to address short-circuit problems between PSE&G's Bergen and Linden switching stations and repairs to and around the utility's Sewaren substation.

To address the short-circuit problem, PJM directed PSE&G to expand the Bergen-Linden corridor into a double-circuit line with higher voltages. The project incidentally also provided additional protection against thermal overloads.

Con Ed and NYPA — as well as Linden VFT and Hudson Transmission Partners, operators of two merchant transmission facilities — challenged FERC's orders approving PJM's five cost allocations from 2014 to 2017. Linden and Hudson reroute electricity from New Jersey into the New York market and resell it at a profit when PJM prices are lower than New York's.

Before they were relieved of liability for the Bergen-Linden and Sewaren projects, the four complainants — which the court labeled the "New York entities" — had been assessed approximately $115 million, which was paid.

PJM allocated most of the costs of the Bergen project ($763 million of $1.2 billion), and all the costs of the Sewaren project ($125 million), via DFAX. In 2014, PJM assigned most of the DFAX costs for Bergen-Linden to Con Ed ($629 million), with the rest allocated to Hudson ($69 million), PSE&G ($52 million) and Linden ($13 million). Sewaren's costs were split between Con Ed ($64 million) and Linden ($61 million).

The DFAX method models how electricity will flow across a new transmission facility at moments of peak grid use and assigns costs proportionally, based on the projected use of the facility in each transmission zone of the PJM grid. DFAX was designed to apply to "flow-based" projects to increase transmission capacity. But the Bergen-Linden and Sewaren reliability projects were non-flow-based.

The New York entities complained that PJM's allocations violated the cost-causation principle because the projects were intended to improve PSE&G's infrastructure, but other parties were assigned most of the costs.

After FERC denied its request for rehearing on the cost allocation, Con Ed notified PSE&G that it would not renew their wheeling agreement. As a result, PJM eliminated Con Ed's cost liability, reassessing Bergen-Linden's DFAX costs to Hudson ($634 million), Linden ($132 million) and PSE&G ($128 million). Hudson and Linden responded by converting their firm withdrawal rights to non-firm, absolving them of cost responsibility under DFAX and

Power Engineers said its work on the underground transmission project in the Bergen-Linden Corridor required a 6,600-foot-long trenchless crossing of Newark Bay, the longest horizontal directional drilling project for 345-kV cable in North America. | *Power Engineers*

PJM News

leaving their costs with PSE&G.

In 2018, FERC reconsidered its use of DFAX on the Artificial Island transmission project, which was designed to address stability problems for three nuclear plants in South Jersey. On rehearing, FERC concluded that the beneficiaries of at least some non-flow-based projects are "not necessarily captured" by the DFAX method and directed PJM to adopt a different cost allocation method for stability-related projects. FERC approved PJM's revised "stability deviation" method — which identifies which loads would most benefit from projects that address stability issues — in February 2019. (See *FERC: Stability Deviation Method Best for Artificial Island*.)

But FERC continued to defend the DFAX method for short-circuit projects like Bergen-Linden and Sewaren.

The New York entities contended that because the Artificial Island, Bergen-Linden and Sewaren projects all addressed non-flow-based issues, their costs should all have been allocated similarly.

FERC's Artificial Island ruling concluded that "stability is analytically unique compared to voltage or thermal overload problems," which are both flow-based. But the commission did not address whether short-circuit projects should also be treated differently from flow-based, the court said. "Therefore, FERC could not rationally explain its decision to treat Bergen-Linden and Sewaren differently from Artificial Island by simply pointing to its earlier finding that 'stability is analytically unique compared to voltage or thermal overload problems.' Instead, FERC needed to explain why stability is 'analytically unique' compared to short-circuit issues," the court said.

In rehearing on Linden's protest, FERC insisted DFAX should still be used to assign Bergen-Linden's costs because it was similar to a thermal overload project. But "FERC did not adequately explain why that similarity mattered," the court said. "Short-circuit issues, not thermal overloads, were the primary impetus for [Bergen-Linden]. While [Bergen-Linden] expanded the grid's overall capacity, the same is true of Artificial Island.

"Given the similarities between the projects, basic rule-of-law principles required FERC to justify its different treatment of the projects. It needed to explain why, in contrast to Artificial Island, the costs of [Bergen-Linden] and Sewaren should be assigned via DFAX to the utilities whose electricity flows across the upgraded facilities, rather than to the projects' other beneficiaries," the court continued.

"We do not hold that the use of the DFAX method for short-circuit projects violates the cost-causation principle *per se*. On remand, FERC may be able to provide a more satisfactory explanation of the distinction between stability-related projects and those that address short-circuit issues and to articulate why DFAX cost allocations are appropriate for the latter but not the former. But the commission 'must provide an adequate explanation to justify treating similarly situated parties differently.'"

De Minimis

The court rejected the New York entities' challenges to the use of netting and peak-load assumptions as part of the DFAX model, but it agreed with their complaint over the *de minimis* threshold, which exempts transmission zones with a distribution factor below 1% of cost responsibility.

Because distribution factors measure a zone's use of a facility relative to its total load, the *de minimis* exception depends on the size of the zone, not on the zone's share of the facility's total flow, the court said.

A zone with load of 1,000 MW that uses 9 MW of a 30-MW facility — almost one-third of the total flow — would be exempted because the distribution factor would be only 0.9%.

"The *de minimis* threshold exempts zones from bearing any costs based on their load size — a quality unrelated to the burdens they impose on or the benefits they receive from any individual facility. And in so doing, it unduly discriminates against small zones, which must absorb higher cost allocations after large zones are exempted," the court said. "Peak load sizes vary greatly across the relevant zones, which makes the *de minimis* exception border on absurd."

PSE&G's peak load is about 11,000 MW versus Hudson's 320 MW. "So if PSE&G used 100 MW of flow across a transmission facility (yielding a distribution factor slightly under 1%), and if Hudson had 4 MW of flow across the same facility (yielding a distribution factor slightly over 1%), then PSE&G but not Hudson would be exempt from paying any of the facility's costs, even though PSE&G derived 25 times more of the benefits," the court said. "And because the large PSE&G would not have to pay any costs of the facility, the small Hudson would have to bear a substantially greater share of those costs."

NJ BPU Challenge Rejected

The New Jersey BPU challenged FERC's orders reallocating costs for the Bergen-Linden project from Con Ed, Hudson and Linden to PSE&G.

The court said FERC correctly determined that Con Ed did not have to pay project costs after the termination of the service agreements, noting that the Bergen-Linden project was planned solely by PJM.

The court said the BPU presented a "powerful argument" that Linden's relinquishment of its firm withdrawal rights and its election of firm point-to-point service allowed it to receive the same benefits from the Bergen-Linden project without any of the costs.

But it said it lacked jurisdiction to consider it because the BPU had not first raised the issue in its rehearing requests with FERC.

The BPU also contended FERC conducted a "siloed analysis" that did not consider the "total effect" of its orders, which it said left New Jersey ratepayers with an "exceedingly disproportionate share" of the costs.

"But FERC did perform the kind of back-end analysis that the New Jersey board claims was required," the court said. "FERC recognized that the [Bergen-Linden] project was planned by PJM, and [it] relied on PJM's statement that the project would still be needed in New Jersey 'even if there were no flows on the transmission facilities interconnecting New York and New Jersey.'"

Orders Vacated

The court vacated FERC's denial of two Linden complaints and remanded them for further proceedings. It also vacated the commission's denial of Con Ed's complaint and remanded it for further proceedings on the *de minimis* issue.

It also vacated FERC's 2020 order (*ER17-950*) reallocating the cost of the North Jersey projects reflecting the end of the PSEG wheel and rejecting Linden's challenge and remanded it on both the Artificial Island and *de minimis* issues. (See *FERC Rebuffs Challenges to PJM Tx Cost Allocation*.)

"FERC did not raise a procedural bar to the New York entities' challenges there, instead rejecting them on the merits for reasons we have found defective," the court said. "On remand, FERC may consider in the first instance whether the challenges to PJM's 2017 cost reallocation are procedurally barred." ■

PJM News

IMM Report Notes Rising Fuel, Congestion Costs in PJM

By Rich Heidorn Jr.

Real-time load-weighted LMPs averaged $67.77/MWh in the first six months of 2022, a 121.3% increase from a year earlier and the largest such spike in the first two quarters since the PJM markets launched in 1999, the Independent Market Monitor reported in its State of the Market *report* for the second quarter.

The total price of wholesale power increased almost 70% to $95.93/MWh for the first six months of 2022, with energy, capacity and transmission charges representing 98% of the total. Transmission costs per megawatt-hour have exceeded capacity costs since the third quarter of 2019, the Monitor reported.

Almost half of the $37.15/MWh increase was a result of higher fuel and emission costs, with coal and natural gas prices doubling in eastern PJM, the Monitor said. Average real-time loads also were up, increasing by 1.9% to 87,616 MWh.

Congestion costs — LMP price differences resulting from binding transmission constraints — increased by almost $792 million (223.7%) over the same period. Only 31.5% of congestion costs paid by customers for the 2021/22 planning period ending in May was returned to them through the auction revenue rights (ARRs) and self-scheduled financial transmission rights revenues offset, the lowest offset since ARRs were implemented, the Monitor said.

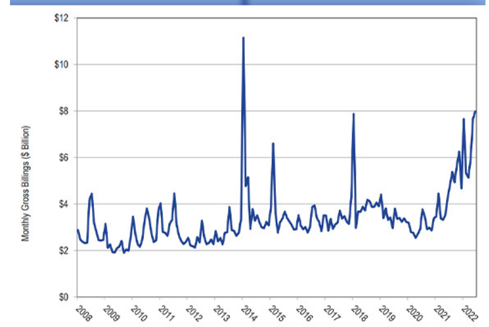
"Congestion belongs to customers and should be returned to customers," the Monitor said. "The goal of the FTR market design should be to ensure that customers have the rights to 100% of the congestion that customers pay."

Generation from coal units dropped 6.4% in the first six months of 2022, while natural gas-fired generation increased by 5.2%.

Energy uplift charges increased by $2.8 million (3.6%) in the first half of the year to $82.1 million.

The Monitor offered three new recommendations in the Q2 report:

- PJM, rather than the unit owner, should select the time and day that a unit undergoes net capability verification testing, and the timing should not be communicated in advance to the unit owner. The tests, required to demonstrate that a unit has the installed capacity claimed, are submitted for the summer and winter testing periods. The Monitor also said PJM should require actual seasonal tests and that the ambient conditions under which the tests are performed should be defined. PJM currently permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data.
- If energy efficiency resources remain in the capacity market, PJM should codify eligibility requirements for claiming capacity rights and institute a registration system to track and document such claims. The Monitor contends EE should not be included on the supply side of the capacity market because PJM's load forecasts now account for future EE.
- PJM should use a nodal approach for distributed energy resources participating in RTO markets. "The PJM market is a nodal market because nodal markets provide efficient price signals to resources in an economically dispatched, security-constrained market," the Monitor said. "Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed." ■



PJM's net gross billings totaled $39.71 billion in the first six months of 2022, a 77% increase from a year earlier. | *Monitoring Analytics*

PJM Sees Additional $603M Data Center Alley Tx Spend

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — Dominion Energy plans $603 million in additional transmission spending to serve the unprecedented growth of data centers near Dulles Airport in Virginia, and FirstEnergy is also reporting an explosion of data center demand, PJM officials said last week.

"We've seen a lot of data center growth in this particular area, Loudon County," Ken Seiler, PJM vice president of planning, told the Transmission Expansion Advisory Committee on Aug. 9. "Seventy percent of the world's Internet traffic flows through there. Over the last few months [data center demand has] ramped up tremendously. … We're trying to a get a handle on what the projected growth rate and if it's sustainable.

"We've never seen anything like this, being so concentrated," he added. "And we don't see any evidence it's going to be stopping anytime soon."

PJM designated Dominion to construct a $603 million "immediate need" project to address short-term reliability issues through 2025.

Seiler said PJM is looking for "broader, regional-scale projects" to solve reliability problems beyond 2025, to serve anticipated load growth of more than 10,000 MW over next five years in the Dominion transmission zone and FirstEnergy zone in Northern Virginia and Frederick County, Md.

PJM *announced* the Dominion immediate need project last month but provided the first cost data and details at last week's TEAC meeting. (See *PJM Orders Dominion 'Immediate Need' Projects to Serve Load Jump in 'Data Center Alley'*.)

PJM Vice President of Planning Ken Seiler | © RTO Insider LLC

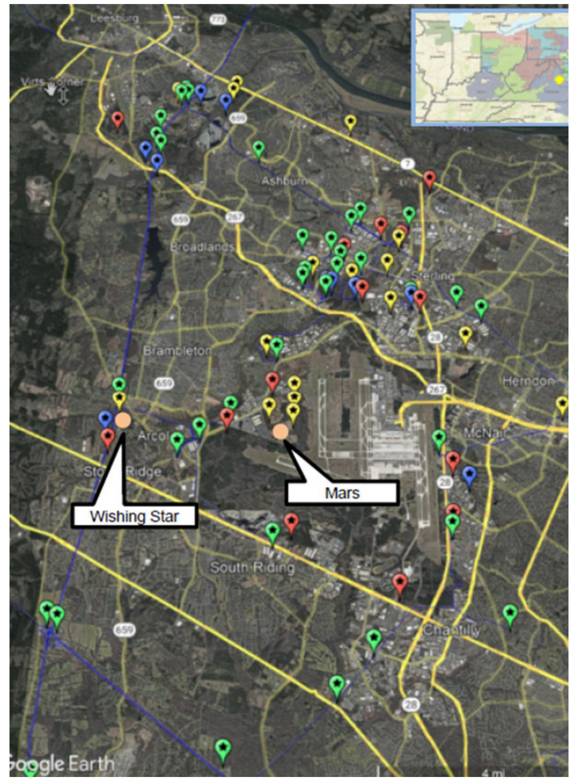
The project will include a new Wishing Star substation ($180 million); a new Mars substation ($167 million); 500-kV and 230-kV line extensions ($132 million); Brambleton substation upgrades ($12 million), Loudoun breaker replacements ($5 million); 230-kV Line #2079/Davis Drive upgrades ($15 million) and risk/contingency/escalation costs ($92 million).

The required service date is June 1, 2025.

Dominion is already constructing 11 "supplemental" transmission upgrades estimated at $197 million and two "baseline" transmission upgrades totaling more than $32 million to address load growth in the area, dubbed "Data Center Alley."

Earlier in the TEAC, Dominion *described* solutions for 13 supplemental projects totaling $366 million, all but two of them the result of data centers or other "customer service" drivers.

Seiler said PJM and Dominion will be coordinating outages and using demand response and behind-the-meter generation to protect existing loads during construction. "Any and all things are on the table at this point," Seiler said.



PJM and Dominion are attempting to serve unprecedented growth of data centers near Dulles Airport in Virginia by building new transmission between new Wishing Star and Mars substations. Existing data centers are identified in green; those in design/construction (red); in planning (dark blue) and inquiry stage (yellow). | *PJM*

In addition, the PJM planning team will be "assembling late this month to consider what additional options do we have to determine what the long-term regional solution will be," he added.

Data centers have grown from 30 MW each to 60 MW and "even as high as 90 MW," said Seiler. Data center campuses have grown from 200 MW to as much as 600 MW each, he said. Seiler said data centers are only providing Dominion two year's notice or less of when they want to begin operations.

Dominion's load is growing by 3% per year for 2022-2027, all of it from data centers, while PJM's load growth has been 0.4% or less annually. (See "Data Center Alley," *Dominion CEO: SCC Order for OSW Performance Guarantee 'Untenable'*.)

Cost Allocation

"It's a little too soon to tell yet," Seiler said when asked about cost allocation of the upgrades. "Right now, I don't have those numbers available."

But he noted that PJM rules require regional allocations for double-circuit 345-kV lines and above.

"The way our rules are set up today, anything double-circuit 345-kV and above — and you're talking 500 [kV] here in some cases — will be allocated 50% on a load-ratio share," he explained in an interview after the meeting. "Then, the lower voltage stuff is all contained within the Dominion zone, or [based on] the distribution factors and where that power flows — so, whoever benefits from it. So, we have to run [analyses on] all that."

The supplemental projects described at the TEAC meeting will be allocated to Dominion's zone but also included in the base cases PJM uses to evaluate potential regional solutions, Seiler said. ■

PJM News

Ohio Supreme Court Gives Go-ahead to Icebreaker Wind Farm

By John Funk

The Ohio Supreme Court last week removed a major legal obstacle to the construction of Icebreaker Wind, a demonstration wind farm in Lake Erie, 8 to 10 miles northwest of downtown Cleveland.

In a 6-1 decision, the court ruled that the Ohio Power Siting Board's May 2020 approval of the project was proper, ending a two-year legal battle that capped at least a decade of effort by the Lake Erie Energy Development Co. (LEEDCo).

The project would be the first freshwater wind project in the U.S. and have to stand up to winter ice flows on Lake Erie. It had been approved by the Ohio Environmental Protection Agency, the U.S. Department of Energy, the Federal Aviation Administration, the U.S. Coast Guard, the U.S. Army Corps of Engineers, the U.S. Fish and Wildlife Service and the Ohio Department of Natural Resources before the PSB ruled on the issue. It had also won significant funding from DOE.

With six turbines on 4.2 acres of state-owned lake bottom, the project would have a total generating capacity of 20.7 MW. The city of Cleveland and Cuyahoga County had agreed to buy about a third of the output. The company must still find takers for the remainder. LEEDCo has also partnered in 2016 with a Norwegian wind developer experienced in offshore wind projects.

The PSB initially approved the project with the condition that LEEDCo turn off the turbines at night for up to 10 months of the year to avoid interfering with bird migration and bats. The company countered that it would not be able to attract or keep investors if it agreed to that provision, as overnight winds are generally more reliable for power production.

After months of negotiation in which LEEDCo committed to enhanced radar surveillance, a sophisticated new collision detection system and a commitment to shut down when or if birds began colliding, the siting board approved the project.

But two residents of an upscale lakeshore community near Cleveland appealed the approval. They argued that LEEDCo had not submitted sufficient evidence for the board to determine the impact of the turbines on birds and bats. The board, which by then had decided to require LEEDCo to report bird collisions, rejected the argument and two subsequent appeals of its decision.

Writing for the court's 6-1 majority decision, Justice Jennifer Brunner explained that the board collected the necessary research to allow Icebreaker to begin construction, while also requiring more data before the company can operate the turbines.

"Rather than requiring Icebreaker to resolve those matters before issuing the certificate, the board determined that the conditions on its grant of the application were sufficient to protect birds and bats and to ensure that the facility represented the minimum adverse environmental impact," Brunner wrote.

LEEDCo Board Chairman Ronn Richard, CEO of the Cleveland Foundation, said Ohio has no choice but to embrace the energy transition to meet the state's power needs. He noted that Intel's decision to build the world's largest computer chip factory near Columbus includes a commitment to power 100% of its operations with renewable energy. Other companies in Northeast Ohio and throughout the state have also set ambitious renewable targets.

Visual simulation of the view of Icebreaker Wind in Lake Erie from the Cleveland Mall | *LEEDCo*

"We're pleased with the ruling from the Ohio Supreme Court," Richard said. "The Cleveland Foundation has supported Project Icebreaker from its inception because this is about more than clean energy; this is about a healthy economy and a healthy community. Project Icebreaker shows that Northeast Ohio — and the entire state of Ohio for that matter — is open for businesses." ■

PJM News

Access to Meter Data Holding Back Residential DR, CSPs Say

By John Norris

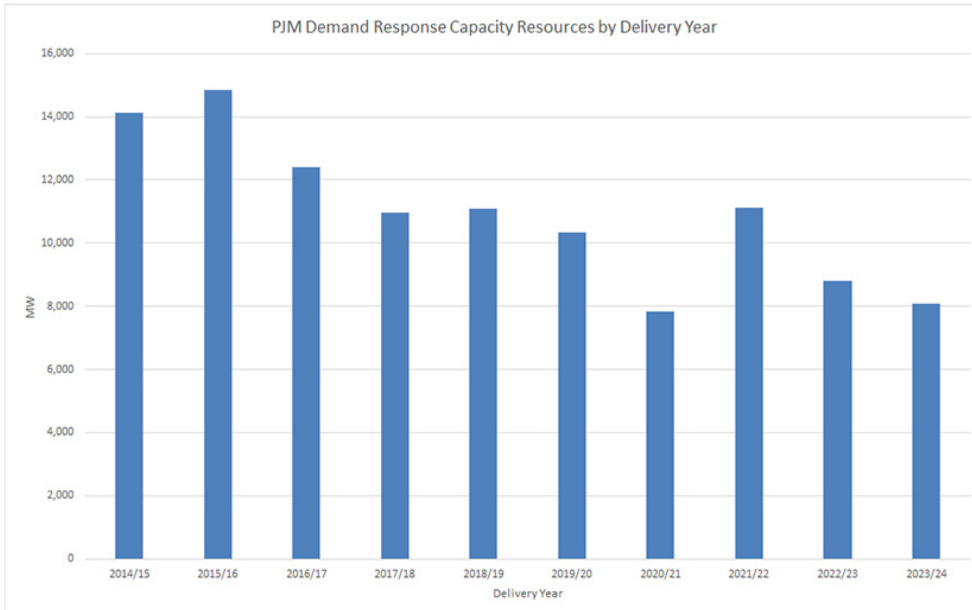
VALLEY FORGE, Pa. — Demand response programs for residential customers and small businesses are being hampered by difficulties accessing interval meter data, CPower Energy Management said in a proposed *problem/opportunity statement* presented to PJM's Market Implementation Committee Aug. 10.

PJM allows the use of sampling to estimate demand response participation for customers lacking interval meters — also known as smart meters — but requires the use of such meter data for customers that have them.

For smart meter-equipped residential customers serving as annual demand response resources, PJM requires not only usage data for settlements and compliance during events and tests, but data from two prior delivery years to establish a winter peak load and peak load contribution (PLC) to set baselines.

Ken Schisler of CPower said electric distribution companies (EDCs) have made it difficult and expensive for curtailment service providers (CSPs) to obtain the data. In some cases, he said, EDCs lack the information. In other cases, the data is cost prohibitive to obtain for small loads.

The introduction of smart meters has not resulted in the expected increase in DR participation, Schisler said. Demand response is an "underdeveloped resource in PJM," he said. "I submit one reason for that is data access."



Cleared demand response capacity has dropped by almost half since peaking at 14,833 MW in delivery year 2015/16. | *PJM*

Cleared demand response capacity has dropped by almost half since peaking at 14,833 MW in delivery year 2015/16. In June's Base Residual Auction, cleared DR totaled only 8,096 MW.

Paul Sotkiewicz of E-Cubed Policy Associates questioned the need for a rule change. "It doesn't sound like an insurmountable problem," he said. "… I'm wondering if this is a solution in search of a problem."

But Aaron Breidenbaugh of Centrica Business Solutions said his company shared CPower's concerns. The cost of obtaining meter data is not as big a concern for large customers but "creates significantly higher costs of customer acquisition" for small loads, he said.

CPower's *issue charge* proposes that stakeholders consider additional use of sampling as an alternative to data from every small customer.

"Do we need data for every single meter?" Schisler asked. "… Is the juice worth the squeeze?" ■

Members near Vote over PJM, IMM Black Start Fuel Requirements

Differ over Regional vs. Zonal Plan, Testing, Incentives

By John Norris and Rich Heidorn Jr.

VALLEY FORGE, Pa. — Capping four years of discussions and analysis, PJM held a *first read* of proposed fuel assurance rules for black start resources (BSRs) at the Market Implementation and Operating committee meetings Wednesday and Thursday.

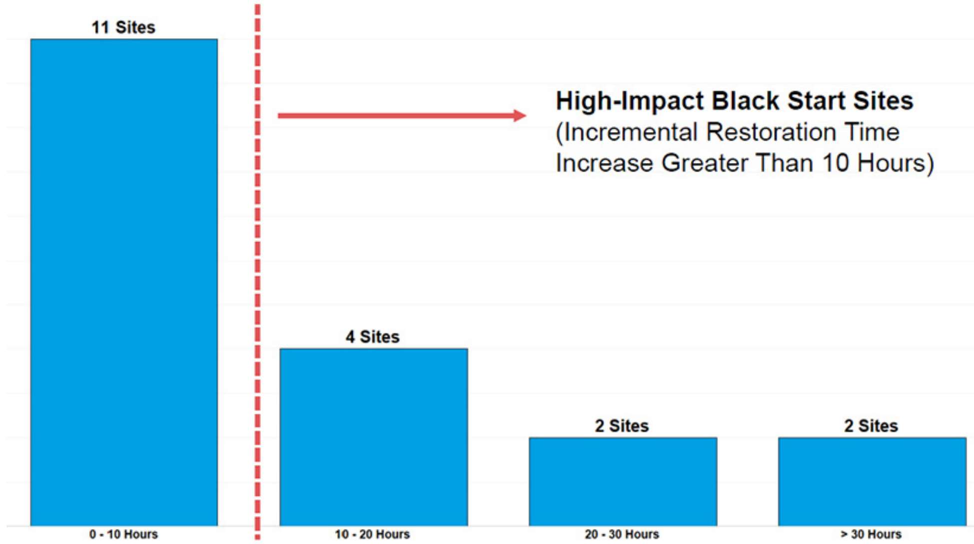
PJM has considered fuel supply capabilities along with other technical, operational and cost factors in awarding black start contracts in the past. In 2017, the RTO increased the weighting of fuel assurance in its evaluation of responses to requests for proposals. But current rules have no fuel assurance requirement other than an existing tariff provision requiring black start units to maintain enough fuel for 16 hours of run time.

PJM's Janell Fabiano said work on the black start proposals — which included a two-year "hiatus" in stakeholder discussions while PJM conducted analyses of restoration times, costs and benefits, and gas supply risks — was an "epic process."

In the 2018 *problem statement* launching the effort, PJM said only about half of the units in its black start fleet were fuel assured "through dual-fuel capability, on-site fuel storage or multiple gas pipeline connections."

The committees heard presentations on two competing proposals, one from the *Independent Market Monitor* and a *second* cosponsored by PJM, Brookfield Renewable and the D.C. Office of the People's Counsel.

Only 23% of stakeholders supported the Monitor's proposal in polling in June. Nearly three-quarters of stakeholders said they supported PJM's proposal before it was combined with one from Brookfield and the OPC, which had received 37% support.



PJM proposed soliciting additional black start units for eight "high-impact" sites in which incremental restoration time would be more than 10 hours with the loss of a non-fuel-assured black start unit. | *PJM*

PJM Package

The PJM package would select black start sites based on their fuel assurance, giving top preference to units with on-site fuel storage (e.g., dual fuel), followed by those connected to multiple pipelines and then gas-only sites connected to a single source fed directly from a gas supply basin or gathering system ahead of an interstate pipeline.

After that, PJM ranks fuel-assured hydro units (pump storage and run-of-river), followed by fuel-assured intermittent or hybrid sites. The last choice would be at least two gas-only sites in a transmission owner's zone connected to two separate interstate gas pipelines.

Additional black start units would be solicited for eight "high-impact" sites in which incremental restoration time would be 10 hours or longer with the loss of a non-fuel-assured black start site.

Mitigation of the eight sites in five TO zones would add $28.2 million to the current annual black start cost of $68.2 million, a 41% jump, according to PJM.

IMM Package

The IMM said existing BSRs lacking fuel assurance should correct the problem or have their black start status terminated, with penalties for nonperformance.

The Monitor also would require predefined emission and effluent waivers to accommodate operations during restoration rather than PJM's proposal that generators use their "best efforts" to obtain permit modifications or waivers.

For dual-fuel resources, the Monitor would require testing of both fuels annually, including a demonstration of the ability to switch between fuels. PJM proposes separate testing for each fuel in the same year. The IMM also would require concurrent annual tests of all BSRs connected to the same fuel source. PJM would not.

PJM would increase the "Z factor" incentive from 10% to 20% for fuel-assured resources selected via the RFP. PJM said the change would cost $436,000 annually.

The IMM would keep the base formula rate incentive factor for such units at 10%. The incentive is multiplied by the sum of fixed and variable black start service costs plus training and fuel storage costs.

The Monitor would also end PJM's current practice of allowing transmission owners to provide black start service under a "backstop" process following two failed RFPs. "TOs should not own generation," the Monitor said.

The IMM also opposed PJM's proposal to allow intermittent resources to seek black start contracts. The Monitor said intermittent resources, other than run-of-river hydro, should not be considered BSRs because they cannot be assured of being available when needed.

PJM's Tom Hauske said the RTO wanted to allow intermittent resources with storage to offer as black start and to anticipate future technologies. "It's not going to be easy" for renewables to qualify, he acknowledged.

In a *presentation* of the IMM's proposal, Monitoring Analytics President Joe Bowring took

PJM News

exception to the fact that PJM had decided not to impose penalties on intermittent resources that registered as fuel-assured BSRs but failed to meet the new rules, saying that this was "discriminatory" and "doesn't make any sense."

PJM said the penalties would be unfair to intermittent resources because the RTO would be responsible for calculating confidence levels for such generators.

Generators are responsible for their own performance, regardless of whether PJM defines the performance standard, Bowring said.

Zonal vs. Regional Plan

Dan Bennett, PJM | *PJM*

Bowring also challenged PJM's plan to award black start sites, and allocate their costs, by TO zone.

"From a PJM perspective, the zonal approach is the correct approach," said Dan Bennett, who presented PJM's proposal. "No one knows a zone more than the transmission operator. They are the right people to be managing this."

Bowring said TO zones are anachronisms under PJM's regional management of the grid and that the RTO should take advantage of cross-zonal benefits.

"The fact that TOs can do it is irrelevant," Bowring said. "There is no magic to zones. Zones are arbitrary. PJM has unfortunately taken the position that TOs are more capable than itself. It's PJM's responsibility to do it."

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said some advocates are not convinced there is a need for black start units in every TO zone. "We are interconnected, unlike ERCOT," Poulos said. "We do have the ability to have other resources help us."

Impact on Existing Resources

Stakeholders voiced confusion and concern over the proposed changes, asking for clarification on how they would impact current BSRs that do not register as being fuel assured.

Paul Sotkiewicz of E-Cubed Policy Associates summarized many of these concerns when asking whether the process would be "voluntary" and whether it "would negatively impact BSRs that do not officially register as being fuel-assured."

PJM responded that the new rules would not impact existing BSRs and were a voluntary process that sought to give additional compensation to eligible generators. Bennett encouraged stakeholders to continue providing feedback or suggestions that would make the packages "stronger because of teamwork."

The BSR discussions exceeded the allotted time in both the MIC and OC meetings. PJM has scheduled a special meeting for Aug. 25 on the issue. PJM is targeting a filing to FERC in December and an RFP in April 2023.

Dual Votes

Because both the MIC and OC took part in discussions, both will be involved in voting on the two proposals, PJM's Fabiano said. Voting will open after the Sept. 8 OC meeting and close at 5 p.m. ET on Sept. 15. Only one representative per voting member may participate; if different representatives vote at the MIC and OC, PJM will consolidate the responses and validate one response per member.

Poulos thanked PJM for its work helping the advocates understand the cost-benefit of the fuel incentives. PJM used a range of probabilities of a coincident blackout and fuel delivery failure and a range of values of lost load to calculate the increase in the expected cost that could result if a black start site were unavailable because of fuel failure.

"I don't think they're all going to be for it, but I certainly think there's going to be more support … than there would have been without PJM's work," Poulos said of his members. ■

PJM TEAC Briefs

$400M in Supplemental Projects Announced

VALLEY FORGE, Pa. — PJM transmission owners last week, led by Dominion Energy, presented the Transmission Expansion Advisory Committee with more than $400 million in supplemental projects.

Dominion *outlined* 13 supplemental projects totaling $366 million; all but two of them are the result of data centers or other "customer service" drivers. PJM has designated Dominion to construct a $603 million "immediate need" project to address short-term reliability issues resulting from data center growth through 2025. (See *PJM Sees Additional $603M 'Data Center Alley' Tx Spend*.)

In addition:

- UGI *presented* a $33 million project to construct a new 230-kV switchyard (nine breakers in a breaker and half configuration) and two 230-kV supply lines of about 2.5 miles to serve a new large load customer in the Nanticoke area.
- PEPCO *presented* plans for a $420,000 project to upgrade an obsolete relay on the 230-kV Ritchie-Oak Grove line (No. 23058) at the Oak Grove Substation.
- PECO Energy *said* it will add a third 230/13-kV transformer at its Master Distribution Substation to relieve surrounding substations and provide capacity for growth at a cost of $800,000.

$24M in Additional Tx Upgrades Needed for Cheswick Retirement

PJM is *recommending* $24 million in additional transmission upgrades to address thermal violations resulting from the March 2022 retirement of the 567.5-MW Cheswick generating plant in the Duquesne zone. The Springdale, Pa., plant was the *last* coal-fired generator in Allegheny County.

In August 2021, PJM *said* its analysis concluded that new and existing baseline projects would resolve any problems resulting from the retirement.

But the RTO told the TEAC last week that it had discovered "missing N-1-1 thermal violations" during a review of the analysis results using 2023 summer and 2027 summer load flow models developed this year. "The further investigation confirmed that there was [an] issue in the study file used for the N-1-1 thermal analysis performed in 2021," PJM said.

The RTO is proposing the installation of a series reactor on the 138-kV Cheswick-Springdale line ($9 million) and a transmission line rearrangement that includes the replacement of four structures and reconductoring the Duquesne portion of the 138-kV Plum-Springdale line ($15 million).

The projected in-service date is Dec. 31, 2024. Operating measures have been identified to address reliability problems before then.

The RTO said it also is conducting reliability analyses for the retirement of NRG Energy's Joliet Units 6, 7 and 8 (1,381 MW) planned for June 1, 2023, in the ComEd zone, and the Dickerson combustion turbine (18 MW) scheduled to retire in the PEPCO zone on Oct. 23, 2022. The Joliet plants — which were converted to gas from coal six years ago — are *closing* because of the Illinois *Climate and Equitable Jobs Act* (CEJA), which requires the state to eliminate carbon emissions from its electricity sector. (See *Illinois Climate Bill Could Force $2B in Tx Upgrades, PJM Says*.)

Officials said the Vineland CT (21.1 MW) in the ACE zone can retire as scheduled on Oct. 10 after an analysis found no reliability violations. ■

— *Rich Heidorn Jr.*

The coal-fired Cheswick generating plant in Springdale, Pa., retired in March 2022. | *Google*

PJM News

PJM Operating Committee Briefs

Russia Showing Restraint in Cyber Responses

PJM Chief Information Security Officer Steve McElwee provided the Operating Committee a security update, saying Russia has continued to show restraint in retaliatory attacks against Western nations supporting Ukraine.

Although there had been concern that Russia would launch widespread cyberattacks, "their focus so far has been to augment their physical attack against Ukraine," McElwee said.

In contrast, the NotPetya attack had "no boundaries on which organizations were victimized," he said. The June 2017 malware attack on the websites of Ukrainian banks, ministries, newspapers and electric utilities also resulted in infections in Western Europe, the U.S. and Australia.

Researchers said the attacks they are seeing against Ukraine are contained to prevent collateral damage. However, McElwee said criminal and hacktivist groups like Killnet continue to threaten attacks and casualties on Russia's behalf. "Most recently, they've been targeting Lockheed Martin," he said.

Hybrid Manual Language Endorsed

The committee endorsed manual language conforming to FERC's July 12 order accepting PJM's clarifications on its rules for hybrid resources and mixed technology facilities (ER22-1420-002). The RTO filed its proposal on March 22.

The changes affect Manual 10: Pre-Scheduling Operations and Manual 14D: Generator Operational Requirements. In Manual 14D, the changes concern metering requirements, outage reporting and voltage schedules, with a new section 13 for mixed technology facilities.

Second 'First Read' on Max Emergency Status for Coal Plants

PJM postponed a vote on competing RTO and Independent Market Monitor proposals for managing remaining run hours for coal-fired and other generating resources limited by fuel shortages or environmental restrictions.

Because of changes to the proposals since the committee's July meeting, "it was decided that another first read would be appropriate," said PJM's Jeff McLaughlin. (See PJM Considers Changes to Max Emergency Status for Coal Plants.)

PJM added references to coal- and natural gas-fired generating units subject to Illinois' Climate and Equitable Jobs Act (CEJA).

The Monitor had multiple additions, including changing the reference to "fuel" to "fuel and consumables." It also added more detail to the conditions that qualify as "fuel limits" for being eligible for maximum emergency status. They would be defined as physical events that affect the infrastructure used to "procure, treat or transport fuel or consumables" that are beyond owner control — meaning the generator has no other procurement options.

"Temporary" interruptions would be limited to seven days, with generators required to

Installation of Lindsey SMARTLINE conductor monitor. | *Lindsey Systems*

PJM News

provide a projected delivery date from the supplier.

The IMM would create a new availability status for "fuel/consumables conservation" that would allow committed capacity resources with 10 days or less of inventory that do not qualify for the maximum emergency fuel limit to make its unit unavailable for economic dispatch. Such units would be subject to a penalty equal to their daily capacity value based on the Base Residual Auction price.

IROL-CIP Cost Recovery

PJM presented a *first read* on a procedure for obtaining reimbursement for compliance with NERC Critical Infrastructure Protection standard CIP-002-5.1, which requires identification of generating units that are critical to the derivation of interconnection reliability operating limits (IROLs).

Resources identified by PJM as an IROL critical resource would submit their capital and recurring costs for review by the RTO and Monitor annually. PJM would make monthly payments to the generators.

The issue will be brought to a vote at the OC's meeting next month.

New Cold Weather Advisory

Members heard a *first read* of manual changes to comply with NERC standards for cold weather preparedness: EOP-011 (Emergency Preparedness and Operations), IRO-010 (Reliability Coordinator Data Specification and Collection) and TOP-003 (Operational Reliability Data).

PJM is creating a new cold weather advisory to clarify RTO and member actions for gathering and reporting information required by the NERC standards. The advisory would be issued more than 24 hours in advance of a cold spell — likely three to five days in advance — and would precede the issuance of a cold weather alert.

The changes will affect Manual 14D: Generator Operational Requirements and Manual 13: Emergency Operation.

Generation owners will be required to ensure updated information on their units' temperature operating limits in Markets Gateway.

PJM added a recommendation to its Cold Weather Preparation Guideline and Checklist to take into account the effects of precipitation and wind during cold weather preparation.

The committee will be asked to endorse the changes at its next meeting.

Manual 39: Nuclear Plant Interface Coordination

Darrell Frogg of PJM reviewed proposed *changes* to Manual 39: Nuclear Plant Interface Coordination as a result of a periodic review. The changes include updated references to NERC's mission and its mandatory standards, as well as a list of revisions to plant-specific nuclear plant interface requirements.

The committee will be asked to endorse these changes at its next meeting.

PPL Dynamic Line Ratings Implementation Confirmed for Sept. 12

PPL is continuing *plans* for introducing dynamic line ratings to the double-circuit 230-kV Susquehanna-Harwood and the 230-kV Juniata-Cumberland lines on Sept. 12, PJM's David Hislop told the committee.

A "go/no go" determination will be announced on Aug. 31, two weeks before the transition.

Assuming a decision to "go," PJM will begin posting PPL's forecasted DLRs at 3 to 4 p.m. on Sept. 12, and begin using the company's ambient tables for reliability studies and the *day-ahead market* for Sept. 14. The RTO will then begin posting PPL *real-time* DLR data at 12 to 1 p.m. on Sept. 14.

Any changes to the plan will be communicated to OC stakeholders via Pardot.

PJM/IMM Proposal on Improving Renewable Dispatch

Members heard a *first read* of a PJM/Monitor proposal to improve the dispatch of renewable generators to address operational concerns.

PJM said it wants to increase the accuracy of renewables' dispatch and improve its ability to forecast near-term changes in resource output. "As the number of renewable resources grows, it becomes increasingly difficult to manually manage the dispatch," PJM said in its *problem statement*.

The proposal would require intermittent units to have an economic minimum of zero and to have an infinite turn down ratio — the difference between eco max and eco min.

The proposal also would require generators to update critical parameters every five minutes for real-time security-constrained economic dispatch (SCED) cases and hourly updates of parameters for intermediate-termed SCED cases. Current rules require hourly updates but provide limited guidance on specific parameters.

Wind resources are currently eligible for lost opportunity costs (LOC) when they are able to follow SCED dispatch instructions and have supervisory control and data acquisition capability to transmit and receive instructions from PJM. The RTO-IMM proposal would allow solar resources to qualify for LOC under the same rules.

PJM currently has no metrics measuring the impact of renewables' dispatch. The proposal would establish metrics that the RTO would review monthly with stakeholders. Potential metrics include renewable forecast accuracy; curtailment frequency; real-time performance versus SCED expectations; and the accuracy of bid-in parameters.

The proposal also calls for development of a look-ahead tool to evaluate renewables' impact.

Intermediate-termed SCED looks ahead about two hours, considering all resource types. The additional tool would be contingent on renewable forecasts reaching acceptable accuracy levels.

Implementation would be no earlier than the second quarter of 2023. The OC will be asked to endorse the proposal at its next meeting. ■

— Rich Heidorn Jr.

PJM news from our other channels

NJ Study Looks at Getting EVs into Overburdened Communities

NetZero Insider

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

PJM News

PJM Planning Committee Briefs

PJM to Make Designated Entity Agreement Filing 'Shortly'

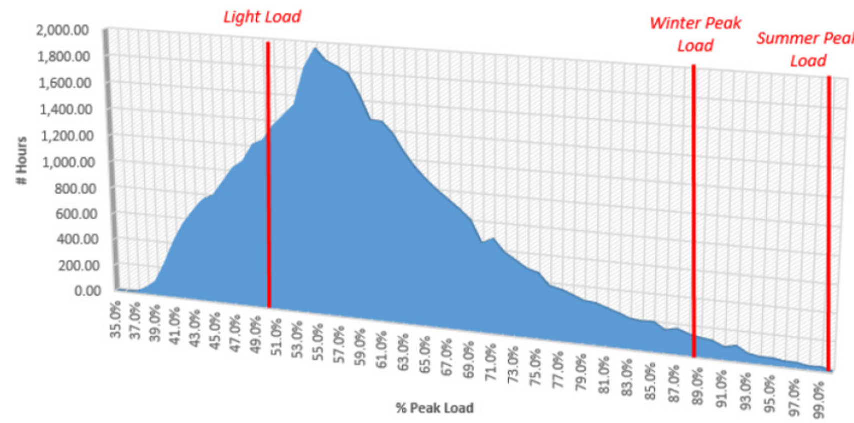
VALLEY FORGE, Pa. — PJM attorney Pauline Foley provided a brief update on the RTO's plans to make a Federal Power Act Section 206 filing asserting that the Operating Agreement's provisions on designated entity agreements (DEAs) are unjust and unreasonable.

Foley said the RTO will assert that the OA's references to DEAs are "overly broad and imprecise."

PJM "anticipates making the filing shortly," she said. "I don't have an exact date."

News of PJM's planned filing prompted the cancellation of scheduled votes on competing issue charges on the matter at the July 27 Markets and Reliability Committee and Members Committee meetings. (See "Application of Designated Entity Agreement," *PJM MRC/MC Briefs: July 27, 2022*.)

On July 26, a group of load-side stakeholders beat PJM to FERC, filing a complaint asking the commission to force the RTO to require incumbent transmission owners to sign DEAs on "immediate need" projects. The complainants contended the RTO has violated the OA by refusing to do so. (See *PJM Challenged on Oversight of 'Immediate Need' Tx Projects*.)



Frequency of RTO load as % of peak (May 1, 2016-April 30, 2021) | *PJM*

Generator Deliverability Test Update

Most stakeholders urged PJM to delay a vote on changes to generation deliverability testing procedures until the rules for effective load-carrying capability (ELCC) capacity interconnection rights (CIRs) are considered.

The deliverability test ensures the transmission system can transmit its generating capacity at summer peak load as well as under light load and winter conditions. The proposed changes are in response to increasing system variability caused by growing renewable penetration. (See "Generator Deliverability Education," *PJM Planning Committee Briefs: July 12, 2022*.)

CIRs set an upper bound on the amount of installed capacity attributed to a generation capacity resource. ELCC resources such as renewables cannot run at their maximum output for more than 24 hours.

"It could be independent and should be independent," Exelon's Pulin Shah said of the two processes.

But other stakeholders — including Apex Clean Energy Group, LS Power, the PJM Public Power Coalition, Old Dominion Electric Cooperative, and economists Paul Sotkiewicz and Roy Shanker — said the issues should be considered together.

"I don't see how it can be done separately," said Shanker. "You could have a whole lot of [generation] that's approved but not deliverable because of changes that happen two months later."

"They need to go hand in hand," said Sotkiewicz, of E-Cubed Policy Associates.

Carl Johnson, representing the PJM Public Power Coalition, said coupling the issues "creates the least uncertainty."

PJM's Jonathan Kern said the RTO is *proposing* to merge summer, winter and light load deliverability testing methods.

Jonathan Kern, PJM | *© RTO Insider LLC*

In June, the PC's special session on CIRs for ELCCs discussed competing proposals from PJM, LS Power, Global Infrastructure Partners' Eolian subsidiary and Sotkiewicz. The group originally planned a final review in July, but the meeting was postponed until late August to allow for more offline discussions to forge compromises. (See "'Time to Get Involved' in Capacity Interconnection Rights for ELCC Resources," *PJM Planning Committee Briefs: July 12, 2022*.) New rules would be implemented for the 2025/26 Base Residual Auction.

The generator deliverability test changes would be made in Manuals 14A and 14B. They would add a new block dispatch approach to dispatch cases. To ensure a realistic dispatch, the base case would not allow any locational deliverability area (LDA) to import more power than their capacity emergency transfer objective (CETO).

The light load period, currently 12 to 5 a.m., would be redefined to include daytime hours from 10 a.m. to 3 p.m. where the RTO's coincident peak load is between 40 and 60% of the annual peak. The default light load temperature would be 59 degrees Fahrenheit.

The new rules also will include more wind and solar in base case dispatches, with fixed solar rising from 38% to 47 to 55% of nameplate capacity in summer. Onshore wind would increase from 13% to 16 to 20%, and offshore wind would jump from 30% to 33 to 38%.

PJM wants stakeholder approval of the deliverability changes by December so they can take effect for the 2028 Regional Transmission Expansion Plan.

Load Model Selection Endorsed

Members unanimously endorsed PJM's *proposal* to use a 2002-2012 load model for the 2022 Reserve Requirement Study.

PJM's Patricio Rocha Garrido said the RTO changed its recommendation from the 2000-2010 model after discovering that a Monte Carlo simulation of the model "distorts the total distribution."

The model selected is based on an analytical method rather than Monte Carlo sampling, he said. "At the 97th percentile and above, the Monte Carlo is not doing a good job."

Sotkiewicz asked PJM to provide written language describing its algorithms "to avoid … confusion." ■

— *Rich Heidorn Jr.*

PJM News

PJM Market Implementation Committee Briefs

Issue Charge Approved on Day-ahead Zonal Load Bus Distribution Factors

VALLEY FORGE, Pa. — The PJM Market Implementation Committee last week approved an *issue charge* to consider a new method of determining day-ahead zonal load bus distribution factors.

The RTO's current rules state that the default distribution of load buses for a zone in the day-ahead energy market is the state-estimated distribution of load for that zone at 8 a.m. one week prior to the operating day. Thus, the share of the zonal load attributed to each node remains constant for all 24 hours, even though the node's share of total load may vary throughout the day because of nonconforming loads, such as data centers and behind-the-meter solar. This can cause a mismatch between the day-ahead nodal loads and real-time state-estimated load, according to the *problem/opportunity statement*.

Amanda Martin, who presented the issue at the committee's meeting Wednesday, said the mismatch is not currently a concern but that PJM expects it to become one with the growth in nonconforming loads.

The committee unanimously approved the issue charge under the "CBIR Lite" (Consensus Based Issue Resolution) process despite the concerns of some stakeholders that the issue is more complicated than portrayed: Martin said it affects a single line in the tariff.

Paul Sotkiewicz of E-Cubed Policy Associates said the issue is not appropriate for CBIR Lite.

"I can think of places in PJM where just a small change [in distribution factors] can change plant commitments. This is not a trivial issue," he said. "It can change pricing. It can change commitments in real time. I don't think we can come up with a solution without doing that hard work [to model the impacts of the change]. Otherwise we're just guessing."

Independent Market Monitor Joe Bowring said he supported PJM's proposal but that it should also create an initiative to consider long-term implications.

Jason Barker, Constellation Energy | © RTO Insider LLC

"Using one hour at 8 a.m. for all 24 hours makes no sense. To me this is clearly and obviously an improvement," he said.

"If it needs more analysis, fine," Constellation Energy's Jason Barker said. "I don't think we need to make a science experiment out of it."

To address stakeholders' concerns, PJM added to the issue charge a requirement that the initiative include an historical analysis to evaluate the impact of proposed solutions relative to the current practice.

The work is expected to take four months, with changes to tariff section 31.7c(i) and updates to Manual 11 and Manual 28.

Variable Operations & Maintenance Cost Development

Members heard a *first read* on competing proposals by PJM and Constellation Energy on changes to variable operations and maintenance (VOM) cost development that differ over the treatment of nuclear refueling costs and associated major maintenance.

The PJM proposal includes default adders for minor maintenance and operating costs; a new review process and timeline; clarifications to definitions of major and minor maintenance; and clarifications to requirements on supporting documentation.

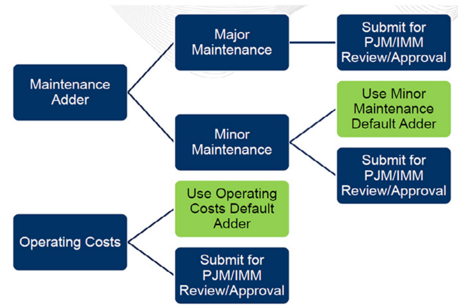
Barker said that Constellation, the largest nuclear operator in the U.S., treats the projects undertaken during planned refuelings as fixed costs because they are scheduled long in advance, irrespective of the number of starts. As a result, he said, they should be included in capacity offers rather than as VOM in energy offers.

Barker said Constellation generally agrees with PJM's desire to move most variable costs into cost-based offers. But he said the RTO incorrectly classifies projects associated with planned nuclear outages as major maintenance costs, defined as costs that "vary directly with electric production."

Nuclear units would not likely have an opportunity to recover costs through a cost-based offer because they are price takers that bid zero into the energy market and are highly unlikely to be dispatched on a cost-based energy offer.

"PJM's definitions don't apply well to the nuclear fleet," he said.

"You're suggesting a significant change to the definition of what can go into VOM versus what's allowable in the capacity market," Bowring said. "This is way beyond the scope of the



Overview of PJM proposal on variable operations and maintenance (VOM) cost development | *PJM*

proposal by PJM. This is about how the review process is conducted, not the definitions of what is VOM."

Barker insisted he was not seeking a "major change."

"What we're trying to do is accurately reflect the nature of nuclear cost accounting," he said.

MIC Chair Lisa Morelli said she was "not prepared to rule on [the procedural question] now."

PJM's Tom Hauske said the RTO considers any cost based on starts and run times as variable and does not distinguish between capital and operating expenses.

PJM's Glen Boyle said the RTO "wanted the stakeholder process to play out and see where the stakeholders were" on the question.

Heather Svenson of Public Service Enterprise Group said her company "strongly supports" Constellation's proposal. It is "not a carve out" for nuclear units, she insisted.

The committee will be asked to vote on the proposals at its next meeting.

Manual Revisions OK'd on Reserve Price Formation

Members endorsed *revisions* to Manual 15: Cost Development Guidelines to conform with FERC's order approving revised energy price formation rules (EL19-58, ER19-1486).

It will be effective Oct. 1, contingent on FERC approval of PJM's compliance filing in EL19-58-012.

The changes remove VOM from synchronized reserve offers and eliminate references to Tier 1 and Tier 2 offers to reflect the consolidation of the tiers. ■

— *Rich Heidorn Jr.*

SPP News

SPP Restricts Board, RSC In-person Attendance

SPP is restricting access to it October in-person governance meetings in Little Rock, Ark. | *WER Architects-Planners*

SPP said last week that it is limiting attendance at its in-person Board of Directors, Members Committee and Regional State Committee meetings scheduled for October at its Little Rock, Ark., headquarters.

Citing a recent rise of COVID cases in Arkansas and the disease's persistence, the grid operator on Aug. 9 said it will restrict access to "rostered members" of the groups and a "handful" of SPP support staff.

"We did not make this decision lightly," SPP said in an email to stakeholders. "We want to protect the health of our stakeholders and mitigate risk for our staff working on campus. We will miss the opportunity to see some of you in person."

The RTO said it will stream the meetings for its stakeholders, promising an "immersive experience for those who attend virtually."

Arkansas' COVID case count has grown to more than 900,000, about 30% of the state's population. The average daily increase over a rolling seven-day period recently fell to 962, its lowest level since early July. Only about half of the state's residents are vaccinated.

The in-person meeting, although lighter in numbers, will be the groups' second since January 2020. They last met together in Dallas in April.

Under SPP's new meeting schedule, the board and RSC will alternate in-person and virtual meetings with the Markets and Operations Policy Committee and Strategic Planning Committee each quarter. The two committees met in Denver in July; they are scheduled to next meet in-person this January in Oklahoma City. ■

— *Tom Kleckner*

SPP News

SPP Continues to Build on Markets+ Offering

Staff, Western Entities Learning from One Another

By Tom Kleckner

PORTLAND, Ore. — SPP and Western entities interested in the RTO's Markets+ "RTO light" offering continued to inch toward one another last week during another development session.

During a discussion on further defining base schedules into various types and their effect on the market, one Western stakeholder cracked, "You even make base schedules fun!"

Those in the know greeted the comment with laughter.

For the uninitiated, base schedules are financial accounting records created by tagging and scheduling bilateral transactions. Should the Markets+ dispatch create an interchange between balancing authorities — there are 38 in the Western Interconnection — the design structure's dynamic tags will be updated to reflect that dispatch.

Powerex's Mark Holman listens to a discussion. | © RTO Insider LLC

Mark Holman, managing director of Canadian power marketer Powerex, spoke up frequently during the two-day session, peppering SPP staff and the stakeholder-led design teams with questions of market designs and products.

A conversation on allocating day-ahead congestion rents that left many non-technical attendees lost in the weeds led Holman to remark that the two sides are "down to the final details."

"I just think this is one of the most complex topics we're going to tackle," he said. "We're trying to allocate congestion rights on top of a multi-[transmission service provider] framework with point-to-point network customers. So, I think we're in excellent shape on this topic, and I'm really happy how far we've gotten in four or five discussions."

Given a day to think, Holman said the two days were a "tremendous success."

"Not only was there a great turnout from so many entities across the West, it is now becoming clear that we have general alignment amongst stakeholders on several of the key market design topics. We are already getting down to discussing the finer details," he said in an email to *RTO Insider.*

Morgan, a golden retriever catching some Zs between Puget Sound Energy's Greg Macdonald and Catherine Whitten, her owner, was among the attendees for both Markets+ sessions. | *© RTO Insider LLC*

Holman acknowledged there is still work to do but said he is optimistic that SPP staff and those interested in Markets+ will soon have a draft governance and market design proposal with "sufficient detail to support moving to the next phase."

That would be drawing up a tariff and market protocols, a task that is scheduled to begin next year.

"We're still talking internally about what that looks like," Bruce Rew, SPP's senior vice president of operations, told attendees when the meeting adjourned Wednesday.

Until then, the RTO and interested Markets+ participants will develop a draft service offering by the end of September. SPP expects a final service offering to be available in November for what it says is a "conceptual bundle" of services (centralized day-ahead and real-time unit commitment and dispatch, and hurdle-free transmission service across the footprint) for utilities that see value in the services but aren't ready to pursue full RTO membership.

Eventually, entities interested in membership will be asked to make a financially binding commitment during the first quarter of 2023.

The two sides will gather again in Phoenix in November.

"We've learned a lot from those out here, and they've learned a lot from us," SPP General Counsel Paul Suskie said. "I think we're driving to a strong consensus. I think structurally we've got a sound straw proposal, and we're really just tweaking it."

Asked what SPP has learned from its potential new members, Suskie said, "What I've really learned is there's a lot of history in the West and because they haven't had many long-term, successful, regionwide organizations, things are still getting a feel for how to cooperate and work together."

SPP has said Markets+ will eventually replace the Western Energy Imbalance Service (WEIS)

SPP News

market it currently operates. When three new members join the WEIS next year, it will be regionally balancing 13.5 GW of load generation. Rew has said an imbalance market is a great introduction to markets but is only a short-term solution for participants.

Recent years have seen CAISO also offer RTO services with its Western Energy Imbalance Market (WEIM), and then build on that with its proposed extended day-ahead market (EDAM). Suskie pointed to those advances and that of the Western Power Pool's Western Resource Adequacy Program (WRAP) as changing attitudes toward regional markets.

Sarah Edmonds, Western Power Pool | © *RTO Insider LLC*

WPP President Sarah Edmonds framed the WRAP as an industry-driven regional approach to help ensure resource adequacy, given the changing resource mix and its increased resource uncertainty. Participation is voluntary, with members facing mandatory resource requirements. The WRAP's bilateral transactions under an existing framework is expected to meet estimated peak winter and summer loads of about 66 GW.

SPP is the initiative's technical services provider, Edmonds said. "They run the studies. They do a lot of the kind of operational facilitation that we're contemplating for WRAP."

The program is the West's take on resource adequacy, she said, which is "part and parcel" of what RTOs do.

"Out here, we're maybe pivoting towards a slightly different model," she said. "If WRAP is successful — and so far, we have tremendous momentum and a lot of trust from our members and customers — then there could be a new construct where you've got different market operators. There's more than one in this space right now and a kind of a complementary provider of the resource adequacy program.

SPP's Steve Johnson (left) and Bruce Rew listen to Markets+ attendees. | © *RTO Insider LLC*

"Now, it would necessitate some kind of interplay or coordination between WRAP and these market programs, and the details of that is just something that we haven't gotten to yet."

There are also plenty of details to work out with the governance strawman. SPP's proposal that one of its independent directors be included on the Markets+ Independent Panel (MIP), which would manage the markets and report to the RTO's Board of Directors, was met with the most pushback. SPP staff have recommended the director have Western experience, but it doesn't necessarily see that person as the MIP chair.

"Our board picks [its] own chair. I don't know why MIP can't pick [its] own chair," SPP CEO Barbara Sugg said.

"That was just our starting point," Suskie said.

"If a board member is on the MIP, how is it independent?" asked Western Resource Advocates' Vijay Satyal. "If you want autonomy, no directors on the MIP is autonomy to me. The director should be *ex officio* and non voting."

Staff assured attendees that the MIP's eventual makeup is up to them. "We're spending more time discussing this than we ever will in 10 years of Markets+," Suskie said.

SPP's takeaways from the governance discussion also included concerns over the $5,000 annual membership fee for non-member participants. Suskie asked for feedback from attendees, noting a waiver might make sense.

"The questions they have today won't exist two years from now. It takes time to get comfortable with each other in a very diverse stakeholder process," Suskie told *RTO Insider* after the meeting adjourned. "You've got to have trust, and that takes time to build. I think we're getting there." ■

"If WRAP is successful ... then there could be a new construct where you've got different market operators."

—Sarah Edmonds, Western Power Pool

SPP Briefs

RTO, SaskPower Agree to Expand Interconnection's Capacity

Canadian utility SaskPower *said* on Wednesday that it has signed a 20-year agreement with SPP to more than quadruple transmission capacity between the province of Saskatchewan and the U.S., effective 2027.

The utility and SPP will expand the 150-MW tie line that connects them to 650 MW. SaskPower said expanding the transmission capacity between the two countries will also improve reliability on its side of the border and allow the utility to export excess power to SPP, creating revenue opportunities.

"Access to this large market ensures reliable energy is available to Saskatchewan to support our own generating facilities," SaskPower CEO Rupen Pandya said. "This will help to manage the integration of more intermittent renewable power such as wind and solar while keeping costs as low as possible for customers."

SaskPower will build the necessary transmission facilities on its side of the border over the next five years, and SPP will be responsible for construction on its side.

SPP has been making international transactions with SaskPower since 2015, thanks to Canadian interconnections that came when the Integrated System joined the RTO. (See *SPP, SaskPower Make First International Trade*.)

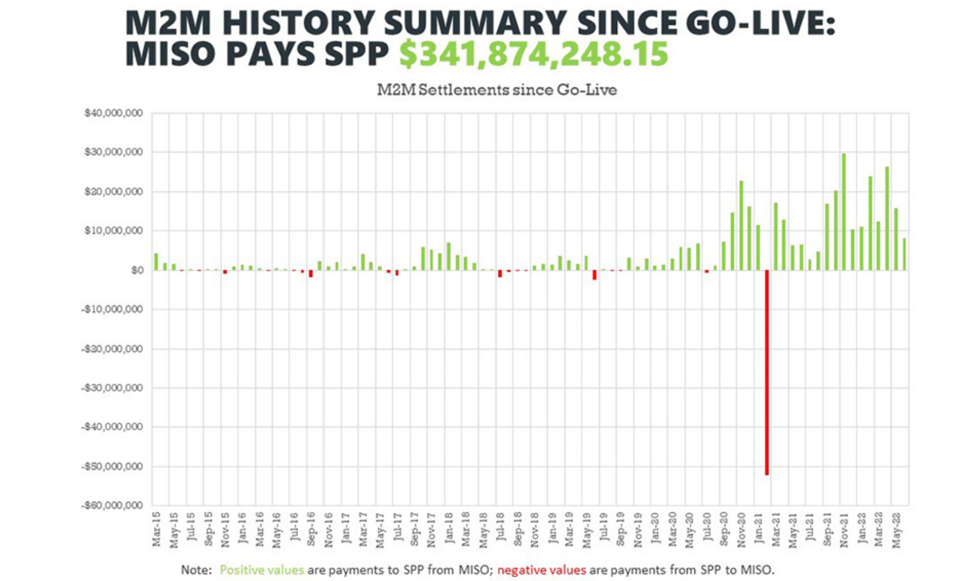
Clements Dissents on Accreditation Order

After two deficiency notices, FERC has approved SPP's request to add capacity accreditation methodology provisions for wind and solar resources to its business practices and planning criteria. The RTO now determines the accredited capacity of qualified run-of-river hydroelectric, wind and solar resources based on historical performance, effective Feb. 15, 2022 (*ER22-379*).

The commission in its Aug. 5 order directed SPP to make a compliance filing within 30 days. The RTO filed its request in November 2021.

Commissioner Allison Clements partially dissented from the order, *tweeting* last week that she did so on the condition that SPP submit revised tariff compliance records. She said the RTO "should have submitted tariff revisions that explain what its proposal actually is."

"Granted, the majority agrees that SPP's proposal falls short of the commission's rule of reason," Clements wrote. "But they take it on faith that SPP will submit satisfactory tariff revisions on compliance, without knowing what those revisions would actually say. I cannot conclude that a tariff change is just and reasonable based solely on its general description."



Market-to-market settlements between SPP and MISO as of June | *SPP*

M2M Settlements up to $341.9M

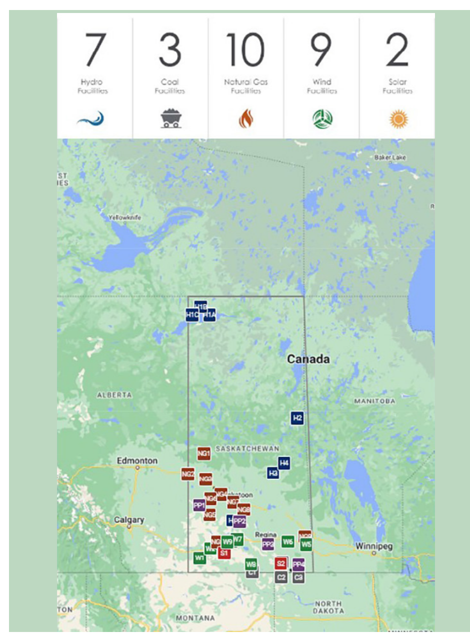
SPP staff briefed the Seams Advisory Group on Friday on three months of market-to-market (M2M) transactions that brought the settlement accruals in its favor with MISO to $341.9 million.

More than half of the three months of transactions came in April at $26.5 million, the third-highest month between the seams neighbors. Settlements in May and June pushed the three-month total to $50.6 million. Permanent and temporary flowgates were binding for 5,907 hours during the three months.

M2M settlements for the redispatch of market flows around congested flowgates have now been in SPP's favor for 16 straight months and 31 of the last 33. The RTOs began the process in 2015.

"The weather wasn't too crazy," SPP's Jack Williamson told SAG. "We're constantly breaking new peak records all the time. We're seeing more and more wind on the system."

Staff also told the stakeholder group that it is developing its first emergency energy exchange agreement with another seams neighbor, Missouri-based Associated Electric Cooperative Inc. The joint operating agreement does not currently have provisions for energy exchanges during energy emergencies, but SPP has similar arrangements with SaskPower, MISO and Public Service Company of Colorado. ■



SaskPower's footprint has three ties with the U.S. | *SaskPower*

— *Tom Kleckner*

Company News

Akins Steps down as AEP President; Sloat to Become CEO

Sloat Named President Effective Immediately; CEO on Jan. 1

By John Funk

AEP CFO Julie Sloat will become the company's CEO on Jan. 1, 2023. | *AEP*

American Electric Power announced Wednesday that Nicholas Akins, CEO for the last 11 years, has resigned from his role as president of the company and been replaced by its current CFO, Julie Sloat.

In a brief *press release*, the Columbus-based utility said its board of directors would also promote Sloat as CEO beginning Jan. 1.

Sloat was named CFO in January 2021 after serving as a senior vice president of treasury and risk for two years and for nearly three years prior to that as president and COO of AEP Ohio.

AEP noted that Akins' remaining time as CEO was part of the corporation's "executive succession plan." After Sloat takes over, he will become executive chair of the board, according to the release, and "will remain an executive and officer of the company."

Akins has been president and CEO of AEP since 2011 and chairman of the board as well since 2014.

"Nick has transformed AEP during the 11 years that he has led the company. His focus on innovation, technology and modernization of the grid and AEP's generation fleet is enabling clean, reliable and resilient energy to fuel growth in the communities that AEP serves," Sara Martinez Tucker, lead director of the board, said in the release. "He also has built an open, collaborative culture that embraces diversity, equity and inclusion. AEP is fortunate that Nick has focused on developing a group of strong and capable leaders to ensure the company's continued success."

Outgoing AEP CEO Nicholas Akins | *AEP*

Akins praised Sloat as "an exceptional leader who has successfully led key strategic areas for the company. Her financial expertise and positive relationship with investors have been essential for the execution of our long-term strategy, enabling us to deliver strong earnings quarter after quarter while continuing to raise guidance and provide consistent dividend growth."

"During her time as CFO, she has improved the financial performance of the company, and she also enhanced the performance and culture of AEP Ohio during the transition to competitive markets," Tucker said. "The board is confident that she is the right person to lead AEP during this dynamic time for the industry and the company."

Sloat initially joined AEP in 1999 as a credit risk analyst but left for 15 months in July 2008 to become vice president of investor relations job with Tween Brands, a clothing company. She returned to the utility in September 2009 as vice president of regulatory case management.

She has a bachelor's degree in business administration with a double major in finance and economics and an MBA from Ohio State University. She completed the Nuclear Reactor Technology Program at the Massachusetts Institute of Technology.

"This is a time of tremendous change and opportunity for AEP as we invest in new energy technologies and infrastructure to provide clean and reliable energy to our 5.5 million customers," Sloat said. "I'm honored to have the opportunity to lead an amazing team of nearly 17,000 employees." ■

Company Briefs

Lordstown Sells 9 Million Shares to Hedge Fund to Raise Cash

Electric truck maker Lordstown Motors last week announced it had raised $23 million in cash through the sale of more than 9 million shares of its stock to YA II PN, an investment fund managed by Yorkville Advisors Global.

The purchase, at $2.50 per share, was the first transaction in an agreement filed with the Securities and Exchange Commission in July in which the fund committed to purchase up to $400 million of the company's shares over three years. Shares of Lordstown closed on Aug. 11 at $2.62.

More: *Securities and Exchange Commission*

Rivian Losses Grow in Q2

Rivian recently reported a net loss of $1.7 billion for the second quarter, which is triple its reported losses from the same period a year ago before the company went public.

Despite the heavy losses, Rivian said it remains on track to start production at its $5 billion Georgia factory by 2024 and has sufficient cash on hand to accomplish the goal. It also reported $364 million in revenue during the second quarter, nearly four times what it produced in the first quarter. Rivian also produced 4,401 vehicles in the period, up 72% from the first quarter.

More: *The Atlanta Journal-Constitution*

Arrival Dropping Uber Project, Electric Bus Plans

EV startup Arrival last week announced it is dropping plans for an Uber electric car and electric buses to refocus on electric vans.

The project to build a dedicated EV specifically for Uber's ride-sharing service could be revived if sales of Arrival's electric van start generating revenue, a report said. Uber revealed the project in October 2021 and was aiming for a 2023 launch.

The decision leaves Arrival's electric van, which is slated to be manufactured at a U.K. facility. UPS has invested in Arrival and ordered 10,000 delivery vans in 2020.

More: *Green Car Reports*

Ford Raises Prices of F-150 Lightning Electric Truck

Ford last week announced it will increase the price of its F-150 Lightning electric truck due to rising materials costs.

The automaker said it will increase the starting prices of the truck by $6,000 to $8,500 for newly ordered vehicles. The truck will now cost from $46,974 for a base model to $96,874 for a Platinum version with an extended-range battery pack.

Ford began making the Lightning in April and sold more than 4,400 through the end of July. It has taken reservations for more than 200,000, with the higher prices going into effect for the 2023 model year.

More: *The New York Times*

Federal Briefs

White House Energy Rule Delays May Threaten Climate Goals

Five of eight Department of Energy appliance standards this year have exceeded the established 90-day review period at the Office of Information and Regulatory Affairs (OIRA), records show, worrying advocates that President Biden could further slip on his climate goals.

Four DOE efficiency standards are under review, including one on clothes dryers that has been stuck for five months.

The delays come as Biden has yet to nominate someone to lead OIRA, which scrutinizes and approves hundreds of "economically significant" regulations drafted by federal agencies every year. Biden has held off nominating an OIRA head longer than former President Donald Trump, who waited until May 2017 — five months after his inauguration. Trump was the slowest president at the time.

More: *E&E News*

Federal Court Reinstates Ban on New Coal Sales on Public Land

Judge Brian Morris of the District Court for Montana last week ordered the Interior Department to pause the issuing of new coal leases.

Morris said that under the Trump administration, the department failed to study the full environmental effects of permitting more mining, as required by the National Environmental Policy Act. The order leaves it to the Biden administration to decide whether to issue a new environmental analysis, which would be required to resume the issuing of leases.

An Interior spokesperson said the department is reviewing the decision.

More: *The Washington Post*

Bill to Speed Energy Infrastructure Faces Resistance

Legislation to speed the approval process for energy infrastructure projects is facing political headwinds, including from Republicans who are skeptical of assurances it will help the fossil-fuel industry and don't like how it was tied to the tax-and-climate bill passed by Senate Democrats.

Sen. Joe Manchin (D-W.Va.) negotiated the deal as companion legislation to the Inflation Reduction Act, saying it would include measures to reduce delays in permitting both clean-energy and fossil-fuel infrastructure. The tax-and-climate plan was approved by the Senate on Aug. 7 in a reconciliation bill that required a simple 51-vote majority. But the permitting legislation wouldn't qualify as a reconciliation measure, meaning Democrats will need some Republican support to get the 60 votes for Senate passage.

Republicans are signaling they will seek to block an attempt by Democrats to attach the proposal to the budget legislation queued up for September. GOP leaders are upset over the tax-and-climate bill it is linked to, which raises some corporate taxes and allots nearly $370 billion to address climate change.

More: *The Wall Street Journal*

State Briefs

COLORADO

Mesa County Commissioners Approve Solar Farm

The Mesa County Board of Commissioners last week approved a conditional use permit for a 151-acre solar farm that will generate up to 48 MW.

Developer SolarGen is working with the Grand Junction Regional Airport and the Federal Aviation Administration to study whether there would be glare from the solar panels. It also plans to do a study of whether the area has burrowing owls. If so, the project would be built during winter months when owls are not nesting.

More: *The Daily Sentinel*

ILLINOIS

Chicago Signs $422M Green Energy Deal

Chicago last week signed a $422.2 million agreement with Constellation New Energy to provide renewable power to government buildings, streetlights and other city assets — and a carbon-free footprint — by 2025.

The plan calls for city-owned buildings that consume the most energy — the Jardine Water Purification Plant, Harold Washington Library and those at O'Hare and Midway airports — to start drawing most of their power from the 593-MW Double Black Diamond solar farm under construction in Sangamon and Morgan counties.

For the rest of the city's energy use, including streetlights, officials said they plan to purchase "renewable energy credits from other sources."

More: *Chicago Sun-Times*

Singh Named Chairman, President of Ameren

Ameren Illinois named Leonard "Lenny" Singh the utility's next chairman and president of Ameren Illinois, effective Aug. 1.

Singh has more than 30 years of utility experience in both electric and natural gas operations and most recently served as senior vice president for Consolidated Edison Company of New York. Singh replaced Richard Mark following his retirement.

More: *Herald & Review*

IOWA

Cedar Rapids City Council Supports Linn County Solar Project

The Cedar Rapids City Council last week unanimously approved a resolution supporting the proposed Duane Arnold Solar projects in Linn County, which would become the state's largest solar and storage facility.

The proposed installation is split into two projects that would use more than 1,100 acres. Duane Arnold Solar I includes a 50-MW facility, while Duane Arnold Solar II includes a 150-MW facility and a 75-MW storage facility. If approved, the project would begin operations by 2025.

The city's support comes three months after the city council in nearby Palo voted unanimously to oppose the county rezoning property within two miles of Palo city limits.

More: *The Gazette*

Turbine Advocates, Opponents Present Arguments to Woodbury Supervisors

Wind turbine opponents and advocates last week packed the Woodbury County Board of Supervisors meeting for a hearing on the county's commercial wind farm setback distances.

The supervisors are considering amending a wind energy ordinance that would increase the distance between turbines and residences from the current 1,250 feet to 2,500 feet. MidAmerican Energy representatives said a 2,500-foot setback would cripple a proposed project by making large swaths of land off-limits due to their proximity to residences. Meanwhile, opponents listed a myriad of concerns and presented the board a petition with more than 720 signatures in favor of the increased setbacks.

Additional discussions of the setbacks are planned for Aug. 16 and Aug. 23.

More: *Sioux City Journal*

MICHIGAN

Consumers to Power State Buildings with Renewable Energy

Michigan and Consumers Energy last week announced a 20-year agreement to power 1,274 government buildings with renewable energy.

The power will come from new wind turbines and solar arrays in the state and will create about 68 MW of power. The state also has contracts with DTE Energy and the Lansing Board of Water and Light to provide renewable power.

Gov. Gretchen Whitmer announced a goal in 2020 to power all government buildings with renewable energy by 2025. The state is on track to meet that goal, Department of Technology, Management and Budget spokesperson Caleb Buhs said.

More: *The Detroit News*

Ford, DTE Energy Ink Renewable Energy Deal

Ford and DTE Energy last week announced an agreement that will have DTE add 650 MW of new solar energy to power Ford's facilities.

Ford previously announced a goal to power all its global facilities with renewable energy by 2035 and be entirely carbon neutral by 2050. Michigan is also targeting carbon neutrality by 2050.

The addition will increase the total amount of installed solar in the state by nearly 70%.

More: *The Detroit News*

SOUTH DAKOTA

Supreme Court Upholds PUC Decision to Grant Wind Farm Permit

The state Supreme Court upheld decisions by the Public Utilities Commission to allow expert testimony and issue a permit for the development of the Crowned Ridge Wind farm in Codington, Grand and Deuel counties.

The court opinions, filed Aug. 3, upheld the permit issued for the 300-MW, 132-turbine project and decisions to allow testimony from two experts.

A group of landowners who sought to intervene in the project's development appealed the PUC decision to issue a permit. That appeal went to the circuit court, and, when it was upheld, was appealed to the Supreme Court. A second appeal also challenged two expert witnesses in the case.

More: *Watertown Public Opinion*

State Briefs

TEXAS

San Antonio to Spend CPS Budget Surplus

After CPS Energy's contributing revenue came in at $75 million more than estimated in San Antonio's 2022 budget, City Manager Erik Walsh said during a briefing on the proposed 2023 budget that most of the money will be spent or returned to customers.

Walsh said the city plans to use $25 million to help support existing city programs and will recommend to the city council that $45 million be returned to CPS Energy customers as a discount on their October bills.

CPS Energy returns 14% of its gross revenues to the city every year. This year, that amount totaled about $436 million (roughly $75 million more than budget projections) due to extraordinarily high summer bills spurred by record-breaking heat this summer, Walsh said.

More: *San Antonio Report*

VIRGINIA

Roanoke Gas Seeks Approval of Renewable Project

Roanoke Gas and the Western Virginia Water Authority are seeking State Corporation Commission approval to convert biogas from a sewage treatment plant into natural gas for homes and businesses.

The $16.5 million system will cost an average residential customer an extra 4 cents per month, according to the application.

More: *The Roanoke Times*