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CAISO Chooses BPA Chief as New CEO

Elliot Mainzer Moves from One Western Giant to Another

By Hudson Sangree

CAISO named the head of the Bonneville Power Administration as its new chief executive Thursday, a move that could help further the ISO's expansion of its Western Energy Imbalance Market and increase its regional influence.

Elliot Mainzer has led BPA since 2013. He will replace CAISO CEO Steve Berberich, whose tenure ends Sept. 30, CAISO and BPA said in concurrent statements. Berberich announced his plans to retire in February. (See *Western RTOs 'Imperative,' Says Retiring CAISO CEO*.)

"Elliot's demonstrated success leading a large, complex power and transmission organization will serve CAISO, our customers and stakeholders well," the CAISO Board of Governors said in a joint statement. "We are happy to have a leader so knowledgeable about

Elliot Mainzer (right) talked with Cameron Yourkowski of EDP Renewable at last year's NIPPC meeting. | © *RTO Insider*

Continued on page 10

Akins: AEP's Actions 'Lawful, Ethical'

Defends Company's Linkage to Ohio HB6 Scandal

By Tom Kleckner

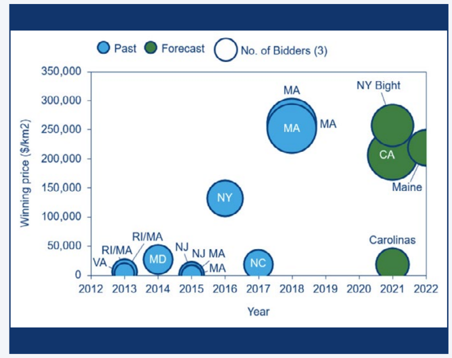
AEP CEO Nick Akins | © *RTO Insider*

American Electric Power CEO Nick Akins said Thursday that federal investigators have not contacted the company about an alleged bribery scheme tied to passage of Ohio *House Bill 6*, and he defended AEP's contributions to a "social welfare organization" linked to the scandal.

"We are not aware of any information suggesting that AEP's participation in the process was anything other than lawful and ethical," he said in prepared comments during a quarterly earnings call with financial analysts. "Based on the facts that we know, we do not believe that AEP is [among] any of the companies specifically described in the [federal charges]. We have not been contacted by any authorities conducting the investigation. If at any point we are, we will cooperate fully."

Continued on page 32

OFFSHORE WIND



Historical OSW lease auction winning price and future forecast ($/km^2) | *Wood Mackenzie*

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In this week's issue

FERC/Federal News

McNamee to Leave FERC in September

Commission to Retain Quorum

By Rich Heidorn Jr.


FERC Commissioner Bernard McNamee | *© RTO Insider*

FERC Commissioner Bernard McNamee announced Wednesday he will leave the commission on Sept. 4, reducing the current four-member panel to three pending the confirmation of his replacement, Virginia State Corporation Commission Chair Mark Christie.

President Trump last month nominated Christie, a Republican, and clean energy activist Allison Clements, a Democrat, to the commission. Clements would fill the seat left vacant by Cheryl LaFleur, who departed nearly a year ago. (See *Trump to Nominate Christie, Clements to FERC*.)

McNamee, whose term expired on June 30, announced in January that he would not seek a second term but agreed to remain on the commission pending his replacement. He is allowed to remain until the end of the current Congress at the end of the year. (See *McNamee Declines to Seek Reappointment*.)

"I intend for Sept. 4, 2020, to be my last day serving on the commission," he said in a statement Wednesday. "Since I announced at our January meeting that I would not be seeking another term, I have continued to work diligently and tirelessly on the important work of the commission. After I leave, I will take some time off and search for a job. Serving as a commissioner has been an incredible honor and an experience for which I am extremely grateful. I thank President Trump for having nominated me and the Senate for having confirmed me. I will have more to say before I leave, but needless to say, I thank the chairman, my fellow commissioners, my advisers and staff, the staff of the commission and all of the FERC community for their support and friendship."

McNamee was confirmed by the Senate in December 2018. The commissioner, who has been commuting weekly to D.C. from his home near Richmond, Va., has said he is eager to spend more time with his wife and teenage son.

Sen. Joe Manchin (D-W.Va.), ranking member on the Senate Energy and Natural Resources Committee, said the panel has not received the paperwork to hold confirmation hearings on the FERC nominees.

"Commissioner McNamee's announcement that he will be stepping down in a month's time means FERC will be operating with only three commissioners as opposed to five. This was not the intention of Congress when the commission was created," Manchin said in a *statement*. "I am hopeful the committee will act quickly to restore a fully seated FERC once we have the necessary paperwork."

The commission will maintain its quorum after McNamee's departure with Chair Neil Chatterjee and Commissioner James Danly, both Republicans, and Democrat Richard Glick. ■

Research Firm: Carbon-cutting, Economic Growth Coexist

By Amanda Durish Cook

World Resources Institute researchers made an economic case last week for climate action, given the COVID-19 pandemic.

Dan Lashof, the global research firm's U.S. director, said 41 states have managed to reduce their carbon emissions in recent years while simultaneously growing their economies. That discredits the maxim that economic growth must come at the environment's expense, he said.

Maryland topped the list of states decoupling carbon emissions and economic growth between 2005 and 2017, according to WRI's new *research*. The state cut emissions by 38% while growing its gross domestic product by 18% during the 12 years. New Hampshire, Alaska, Georgia, North Carolina and Indiana also made the top 10 in cutting emissions while growing their GDPs by at least 13%.

"It's a false choice between shrinking emissions and growing the economy," Maryland Secretary of the Environment Ben Grumbles said during an Aug. 4 WRI webinar.

WRI Research Associate Joel Jaeger said Northeastern and Midwestern states made the most progress cutting carbon while expanding their economies. On the other hand, he said, Texas, the Dakotas and the Gulf States have not made any progress on emission reductions. Idaho was ranked last, experiencing a 17% rise in emissions as its GDP rose by 22%.

Jaeger said states can use large investments in clean energy to help restore the nation's pandemic-stricken economy.

Lashof said a $1 million investment in clean energy in the U.S. creates twice as many jobs in the medium- to short-term than $1 million spent on fossil fuels.

"This is an ideal moment to scale up manufacturing and export of various low-carbon technologies," said WRI Senior Associate Devashree Saha. Low interest rates typical in recessions make it a "particularly good moment," she said.

Saha estimated that states need "substantial, but manageable" investments in low-carbon infrastructure. She said the U.S. would need additional annual investments equivalent to about 2% of GDP.

"Even at 2%, that is well within the historical range," she said. "Energy spending in the United States is at a low point now at around 6% of GDP but has fluctuated to as high as 13%."

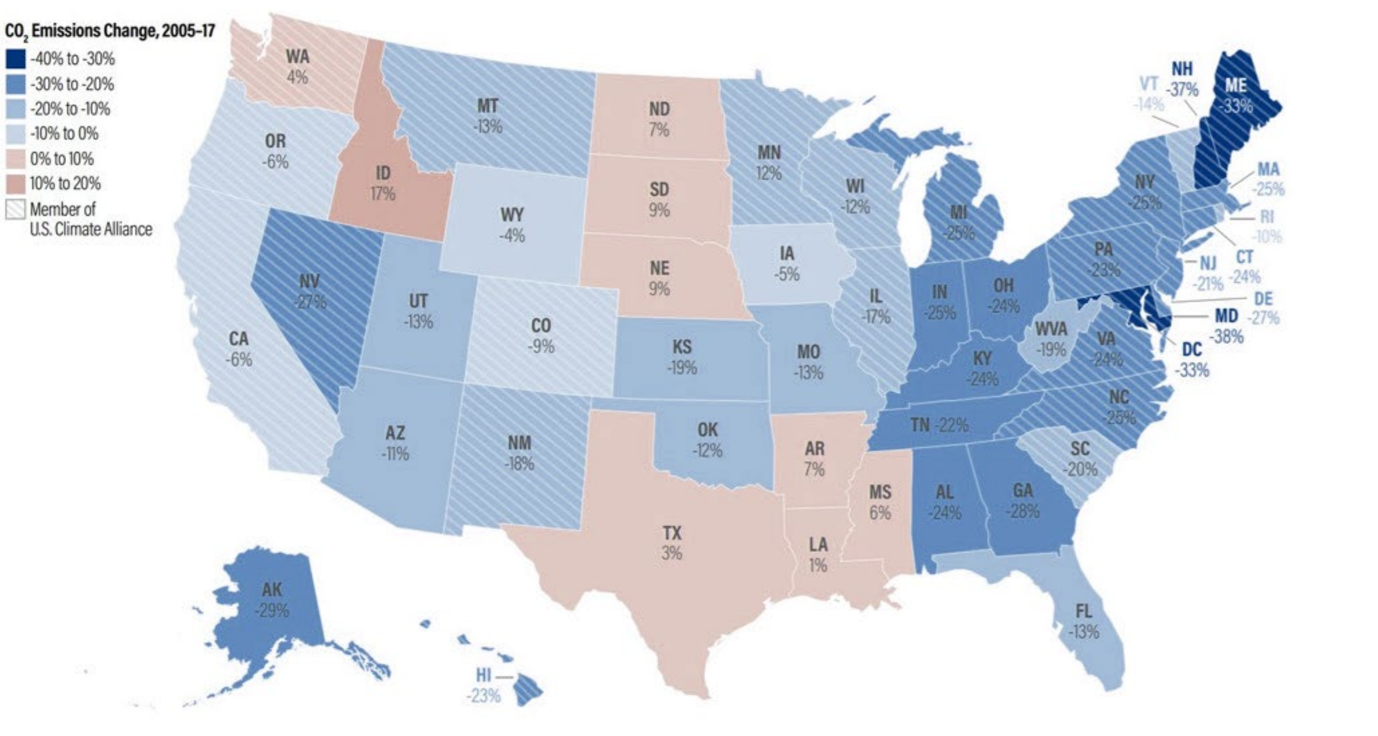
WRI maintains the investments would be money well spent.

"Ignoring climate change is expensive. … Delaying action on climate change will further expose the United States to costly damages from climate impacts, air pollution and other public health crises," Jaeger said, using the nation's response to the COVID-19 pandemic as an example. He estimated that without new climate policies, the U.S. could encounter economic damages equivalent to anywhere from 1 to 10% of GDP/year by 2100.

To honor the Paris Agreement's more ambitious target of limiting global warming to 1.5 degrees Celsius, the U.S. needs to cut net emissions by 40 to 50% from 2005 levels by 2030 and aim for carbon neutrality by 2050. WRI said that means U.S. emissions must drop more than twice as fast from 2018 to 2030 than they did from 2005 to 2018.

WRI staff said that can be done with strong federal climate policies, such as carbon pricing and more investment tax credits.

"I think the federal government can amplify these efforts," Saha said. ■



Carbon emissions change 2005-2017 | *WRI*

FERC/Federal News

OSW Study Sees $166 Billion in Investment by 2035

By Michael Kuser

A new study finds that Bureau of Ocean Energy Management offshore wind area lease auctions over the next two-and-a-half years could initially pump $1.7 billion into the U.S. Treasury while potentially creating 80,000 jobs and $166 billion in capital investment through 2035.

"We're talking about five lease areas, offshore New York, North Carolina, South Carolina, California and Maine, and these areas could unlock tremendous energy and economic potential," Erik Milito, president of the National Ocean Industries Association (NOIA), said at a press conference last week.

NOIA commissioned the *study* by research group Wood Mackenzie with three other groups: the American Wind Energy Association, the New York Offshore Wind Alliance (NYOWA) and the Special Initiative on Offshore Wind (SIOW) at the University of Delaware.

"From the NOIA perspective ... there is a very strong synergy between offshore oil and gas and offshore wind ... and the same shipbuilders, heavy lift vessel operators, steel fabricators and other companies who built the Gulf of Mexico oil and gas business stand ready to lend their expertise to the American offshore wind industry," Milito said.

Feng Zhang, managing consultant for Wood Mackenzie's power and renewables division, said the study mainly looked at areas from the New York Bight and south, plus California, but that interest was also "very high" in possible call areas in the Gulf of Maine.

"From the study, we found that if the relevant policy can be put in place, if BOEM and other industry parties can act very quickly, then potentially 2 million acres of federal waters in those areas can go to auction as soon as 2021 and 2022," Zhang said.

Jump Starter

Additionally, the findings indicate that new offshore wind leases could be a short-term way to jump-start recovery from the economic slowdown caused by the coronavirus pandemic, Zhang noted.

The study found that investment in the country's offshore wind industry will total $17 billion by 2025, $108 billion by 2030 and $166 billion by 2035.

"From 2022 to 2035, capital investment of $42 billion will go to turbine manufacturers and the supply chain, $107 billion will go to the construction industry and $8 billion will go to the transportation industry and ports. Annual capital investment for operations and maintenance activities will increase to $2.4 billion in 2035," the study said.

Long-term, new OSW projects will provide 28 GW of new clean energy resources to power 20 million households and support 20,500 jobs annually for decades beyond 2035, the study found.

The other study sponsors issued statements lauding the economic and environmental benefits of OSW development.

"States along the eastern and western seashores have a massive domestic clean energy resource and many states have set ambitious offshore wind goals to reap the economic and environmental benefits that offshore wind offers but cannot achieve those goals with existing leases," said NYOWA Director Joe Martens. "It's time for the federal government to act with the same urgency as the states."

"We're on the cusp of a rare opportunity, but the U.S. remains far behind other countries in harnessing offshore wind technology," said Laura Morton, AWEA senior director of offshore wind. "It's time for us to unleash this abundant domestic energy source that will deliver tens of thousands of new jobs, revitalize coastal ports and expand manufacturing opportunities to reap major economic and environmental benefits."

"Offshore wind development can be a major part of the solution to our country's most pressing energy needs and our country's most immediate economic woes," said Nancy Sopko, executive director of SIOW. "Unleashing the potential of offshore wind power through immediate and consistent auctioning of new lease areas can help the United States rebound from the greatest economic downturn in our nation's history." ■

Figure 5.1 Annual job supported by states

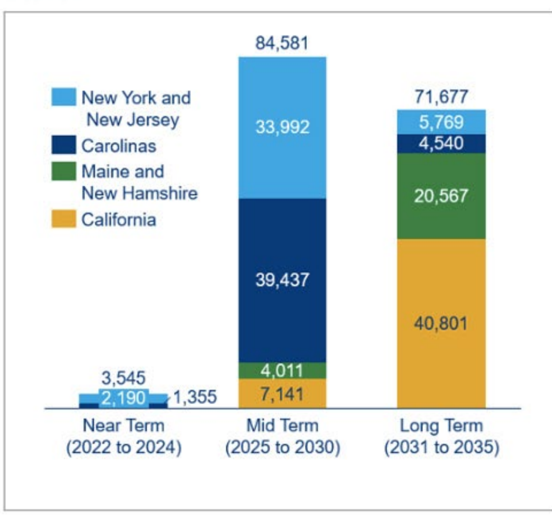
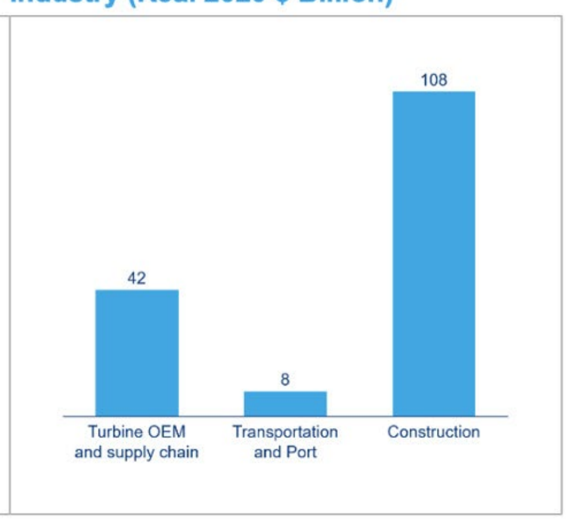


Figure 5.2 Capital Investment by industry (Real 2020 $ Billion)



The report shows OSW development supporting approximately 80,000 jobs annually from 2025 to 2035. | *Wood Mackenzie*

FERC/Federal News

Experts Say Policy Lags Inhibiting Smart DER Use

By Amanda Durish Cook

Experts last week said it's mostly policy — not technology — holding back widespread adoption of distributed energy resources supported by smart technology.

Those opinions were on display during Austin, Texas-based electricity data research organization Pecan Street's "Smart DERs — The Missing Link" webinar Friday.

Eaton Research Lab Engineering Specialist Hossein Ghassempour Aghamolki said there's still a long way to go in smart DER adoption and that the lack of clear, uniform rules is partly to blame.

"We don't have a universal strategy. … Every market, region [and] state has its own policy," he said. Part of the problem is that utilities see DERs as a barrier rather than a tool that can be leveraged through smart meters and load forecasting, he said.

"If the business model is there, the technology can catch up," Ghassempour Aghamolki said.

Arnela Smajlovic, manager of Siemens' Microgrid Management System, said microgrids are already able to bid into markets for dispatch instructions on behalf of the DERs they manage. She said that scenario can be realized today, but it lacks a business model for commercial use and monetized incentives.

"This concept is all well ahead of its time technology-wise. … We need to get over this limited use of microgrids," Smajlovic said. "We're waiting for the business model to catch up. … It's the [state] commissions that have to agree on how we use this technology."

Shashank Pande, a Siemens product manager, said smart DER controllers have improved drastically over the last seven years but are still somewhat limited in their capabilities.

"There's a lot of room to grow in the future," he said, noting that while inverters improve continuously, constraints involving data sharing and a lack of real-time control still hinder widespread DER systems.

In the meantime, Pande said utilities could do more to expand demand response and time-of-use programs.

Bandera Electric Cooperative CEO William Hetherington said his co-op near San Antonio is focused on incorporating DERs in a rural setting, a completely different challenge.

Hetherington said the co-op began offering rooftop solar installations and programs after getting tired of third-party solar companies hoodwinking members by overcharging and underperforming on generation programs.

The result is Tesla Powerwall solar batteries "scattered throughout the hills of Texas," he said. Hetherington said Bandera uses the Apolloware DER management system to analyze energy use and avoid overloading inverters.

The co-op has installed about 200 Apolloware systems and hopes to add another 1,000 by the end of 2021, he said. So far, the co-op simply monitors and provides pricing signals and doesn't perform load control. Hetherington said the idea is that customers get to choose when to respond to price incentives.

"For some reason, people get really upset when you turn their AC off," he joked. ■

| Pecan Street

FERC/Federal News

FERC Report Touts High-voltage Benefits

By Robert Mullin

Development of new high-voltage transmission lines could provide myriad benefits for the U.S. electricity system, including improved reliability, greater sharing of resources across regions and a means for states to achieve environmental policy goals, FERC said in a recent report to Congress.

But such a transmission buildout also faces significant obstacles, given the patchwork of federal and state regulations developers must navigate to develop projects, including in existing rights of way.

The *report* is a product of the 2020 Further Consolidated Appropriations Act, which directed FERC to provide the appropriations committees of both houses of Congress with a study "outlining the barriers and opportunities" for high-voltage transmission in the U.S. Although the report was dated June, it was apparently sent to Congress last week.

While the report offers no concrete steps for policymakers to take, its findings offer a boon to renewable advocates, buttressing the case for building transmission to tap resources in remote areas with an argument favoring the accompanying reliability benefits.

"High-voltage transmission can improve the reliability and resilience of the transmission system by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system [while also] providing greater access to location-constrained resources in support of renewable resource goals," the report says.

"Americans for a Clean Energy Grid is excited to see the strong endorsement of large-scale regional and interregional transmission," said Rob Gramlich, the organization's executive director and president of Grid Strategies. "The report begins an important national discussion about making much greater use of highway and rail corridors as a way around some of the well known barriers to transmission."

Reliability and Resilience

FERC's study defines "high-voltage" transmission as AC lines 345 kV or above and DC lines of at least 100 kV, including overhead and underground networks. It notes the land-use efficiency of transmitting power at higher voltages, which reduces line losses, ensuring that a greater volume of power generated will reach its destination.

"For example, one 765-kV line on a 200-foot-wide right of way can carry the same amount of power as 15 double-circuit 138-kV lines with a combined right-of-way width of 1,500 feet," the report says.

| © RTO Insider

The report addresses four key reliability and resilience benefits of high-voltage transmission:

- Sharing of resources across regions by improving interregional power transfer capability. FERC points out that high-voltage transmission can allow a region to access additional generation when local resources become unavailable. The report notes that during the 2014 and 2019 polar vortex events, the East and Midwest experienced high generator unavailability in concert with demand spikes. During the 2019 event, imports served 9% of load, compared with 3% during the 2014 event. But FERC cautions that "the potential benefits provided by proposed and existing high-voltage transmission are not uniform and need to be studied and verified with detailed simulation modeling of the transmission grid prior to integrating any proposed high-voltage transmission solution."
- Aiding with restoration and recovery after an event. FERC said that during a wide-area blackout, system restoration can benefit from neighboring in-service transmission facilities to restore generation, lines and electrical service, especially in cases where local black start units become unavailable.
- Improving frequency response. The report notes that HVDC lines between neighboring interconnections can provide frequency support in cases of a large loss of generation.
- Enhancing the stability of the interconnection transmission system. Citing the operation of the Pacific DC Intertie linking the Pacific Northwest with Los Angeles, FERC notes that active modulation of the line has been used effectively to maintain system stability in the Western Interconnection "by dampening interarea modes of oscillation."

The report also cites the recent CapX2050 *study* by 10 Midwestern utilities, which found that "retirements of dispatchable generation and the movement toward non-dispatchable wind and solar generation will change transmission congestion patterns and introduce more variability in power flows, thus requiring new solutions to mitigate congestion and ensure reliability." (See *CapX2050 Calls for More Tx, Dispatchability in Midwest*.)

Opportunities, Obstacles

The "opportunities" section of the report points to trends that could fuel the develop-

FERC/Federal News

ment of new high-voltage transmission, including states' renewable portfolio standards.

"These regulatory mandates and voluntary targets are contributing to the buildup of renewable energy resources (e.g., solar, wind, hydropower and geothermal) that are often located in remote areas far from population centers. Transmission developers have proposed numerous high-voltage transmission projects in the United States that could integrate renewable energy resources onto the grid and connect them to regions with high electricity demand," the report says.

The report also points out that high-voltage transmission developers could benefit from the effort of states and localities to increasingly electrify transportation and building heating to reduce carbon emissions. It cites a 2019 Brattle Group *study* that finds "the U.S. will need an average investment of $3 billion to $7 billion per year through 2030, in addition to investments needed to maintain existing transmission systems and integrate renewable energy generation to meet existing load, to meet the changing needs of the system due to electrification."

Another upshot of increased transmission buildout: improved competitiveness in wholesale markets through reduced congestion and the increased ability of low-cost resources to participate. To support the claim, FERC cited *2017* and *2019* reports from ISO-NE showing how new transmission could help New England integrate low-cost resources, decrease congestion and uplift costs, and reduce renewable energy curtailments.

The report delves into how transmission development could benefit from the existence of federal and state laws that support co-location of lines along transportation corridors, including highways, pipelines, railroads (both existing and retired) and canals.

"In some cases, the co-location of transmission in transportation corridors could reduce both the negative effects caused by a project and the cost of project development. Siting transmission in transportation corridors could minimize the creation of new rights of way on undisturbed lands, which could result in reduced effects on private landowners and environmental, cultural and visual resources," the report says.

The report additionally points to FERC's own efforts to encourage interregional transmission development, including issuing Order 1000 in 2011, which aimed to address deficiencies in the transmission planning and cost allocation requirements, including participation by nonincumbent developers in regional planning processes, interregional coordination, and methods to allocate the costs of new regional and interregional transmission facilities.

But FERC acknowledged that transmission development still faces significant barriers in the post-Order 1000 world, especially the number of new projects being developed outside the competitive processes envisioned in the order. Those include the continued ability of incumbent transmission owners to maintain a federal right of first refusal for local projects and upgrades, as well as the existence of threshold limits (such as costs and voltage levels) and other exceptions to Order 1000 requirements in regional planning processes.

"Some entities have suggested that incumbent transmission owner utilities may have a preference for developing projects outside of regional competitive transmission planning processes, which may obviate the need for longer-term solutions that might qualify for these processes," the report says. "Others argue that the transmission development occurring post-Order No. 1000 is focused on reliability and local needs, with only a modest increase in regional projects to address market efficiency and public policy needs."

The report also addresses barriers to development in co-location corridors. FERC points to the example of development along highways, where the Federal Highway Administration (FHWA) and state transportation agencies share joint authority. The state agencies develop the standards they will use to approve applications from utilities, which FHWA must review to ensure consistency with federal guidelines.

"Some states' utility accommodation policies expressly prohibit transmission and other longitudinal utility facilities in highway rights of way. Others restrict the co-location of transmission in highway rights of way based on various factors (e.g., transmission voltage or specific highway features)," the report notes.

Siting of high-voltage transmission in other areas generally falls under state jurisdiction, requiring developers to negotiate multiple state processes, as well as those at the federal and local levels — and all this after navigating regional transmission planning procedures, FERC notes.

"The time required to develop a high-voltage transmission facility that meets mandatory reliability standards, maximizes system benefits and strikes a balance among interested stakeholders (including states) can be in excess of a decade," the report says. ■

CAISO/West News

California Needs Huge Number of EV Chargers

Projected Sales not Enough to Reach Goals

By Hudson Sangree

California will need to double the pace of electric vehicle sales and install millions of chargers to meet its goal of having 5 million EVs on the road by 2030, researchers told the state's Energy Commission (CEC) in four sessions on EV charging infrastructure last week.

The state will likely hit its midterm target, established in an executive order by former Gov. Jerry Brown, of having 1.5 million zero-emission vehicles (ZEVs) by 2025, assuming an 11% sales growth, said Joshua Cunningham, chief of the Advanced Clean Cars Branch at the California Air Resources Board (CARB), which regulates vehicle emissions.

But the pace of sales is projected to increase incrementally to 13%, which is not enough to meet the state's long-term goal, Cunningham said. CARB predicts there will be 2.5 million EVs sold by 2030, he said.

"We'll only to get about half of the electric vehicles we think we need under the prior governor's target of 5 million by 2030 in current business-as-usual policies," Cunningham said.

CARB presented another "extreme sales trajectory" scenario in which all vehicles sold in the state would be EVs or plug-in hybrid vehicles by 2035. Even that, however, will not be enough to meet the state's goal, mandated by another Brown executive order, of achieving carbon neutrality by 2045, Cunningham said. About 20% of all cars on the road would still use gas as their sole fuel source under the scenario, he said.

The transportation sector is the biggest single source of greenhouse gasses in the state, contributing 37% of all carbon emissions. Light-duty vehicles, mainly personal vehicles, are responsible for 28% of all GHGs.

The only way of reaching the state's decarbonization goal is to sell 5 million ZEVs by 2030, Cunningham said. CARB is working to determine policy changes needed to make that happen, the results of which will be issued in the coming months, he said.

CARB's board members will likely vote on more stringent vehicle regulations for post-2026 model years next year, he said.

"We recognize this is a trajectory that needs to be further reviewed, and that's what we're doing this fall," Cunningham said.

Millions of cars, trucks and buses in California will need EV charging infrastructure by 2030. | *California Energy Commission*

Meeting Charging Demand

If the state does have 5 million EVs on the road by 2030, plus medium- and heavy-duty trucks and buses, it will need far more charging infrastructure, researchers said.

State law (Assembly Bill 2127, signed by Brown in 2018) requires the CEC, working with CARB and the Public Utilities Commission, to assess EV charging infrastructure needs. The CEC and outside researchers use a suite of computer simulation and modeling programs to do that.

Eric Wood, a research engineer with the National Renewable Energy Laboratory, said that of the projected 5 million personal EV owners in 2030, 82% will have access to charging in single-family homes, most requiring new wall chargers.

Providing charging at apartments and workplaces, and in public settings such as shopping centers or gas stations, will require an additional 565,000 to 1.15 million plug-in parking spots, Wood said.

"We estimate that 3.4 [million] to 3.8 million plugs will be necessary to meet demand at single-family homes, with an additional 150,000 to 300,000 level 2 plugs being necessary at or near apartment buildings," he said. "Demand for level 2 charging away from home is estimated to require up to 358,000 while-at-work plugs and up to 413,000 while-in-public plugs."

Projected demand is based on the "aggressive forecast" from CARB and applied by NREL "in an attempt to have infrastructure deployment lead vehicle sales," Wood said. But the figures are fluid, he noted, requiring additional research underway at the University of California, Davis, and other institutions.

Researchers are still working to estimate charging needs for medium- and heavy-duty vehicles such as school buses, delivery trucks and tractor-trailers, said Bin Wang, an energy and environmental policy research scientist with the Lawrence Berkeley National Laboratory.

CARB's clean-truck regulations require an increasing number of trucks sold in California to be ZEVs starting in 2024 and for all trucks sold to be ZEVs by 2045, he noted.

Preliminary estimates show the state must deploy at least 67,000 50-kW chargers and more than 10,500 350-kW chargers to serve future demand, the scientist said.

Heavy-duty trucks will need the higher-voltage chargers to fuel up quickly during the day, he said, while the lower-voltage chargers can fuel fleet vehicles overnight.

"I want to emphasize that these are our first preliminary results, which are subject to change as we keep gathering more data," he said. ■

CAISO/West News

CAISO Chooses BPA Chief as New CEO

Elliot Mainzer Moves from One Western Giant to Another

Continued from page 1

integrating renewables and passionate about building on CAISO's organizational strengths and momentum toward low-carbon electricity."

Mainzer has been credited with expanding BPA's efforts to integrate large volumes of wind generation, adding to the already immense hydroelectric resources in the Pacific Northwest. The federal power giant generates 23,000 MW of carbon-free electricity and operates 15,000 circuit miles of high-voltage transmission lines. Its footprint covers an area larger than France, encompassing the watersheds of the Columbia and Snake rivers.

Under Mainzer's leadership, BPA agreed in September to join CAISO's Western EIM starting in 2022. (See *Bonneville Power Signs Agreement with EIM*.)

CAISO is pushing hard to expand the real-time EIM to a day-ahead market, an effort that has proven controversial among some stakeholders, who worry about California's control spreading across the Western energy landscape. (See *EDAM Design Could Undermine Tx Rights, Critics Say*.)

Mainzer has expressed his support for the expanded day-ahead market (EDAM) as a means to trade the growing amount of solar and wind power across state lines.

"It's not going be enough to sell all this stuff on a five-minute market," he told last year's annual meeting of the Northwest and Intermountain Power Producers Coalition. (See *NIPPC Members 'Carry On' Without Kahn*.)

Steve Berberich | © *RTO Insider*

On Thursday, Mainzer said he looks "forward to working closely with our colleagues across the West to build on the success of the Western Energy Imbalance Market and further strengthen regional coordination and technology innovation."

The BPA CEO is regarded by some as a bridge builder. In a blog post Thursday, Natural Resources Defense Council Energy Co-director Ralph Cavanagh praised Mainzer's ability to keep an open mind while dealing with disparate interests and forming coalitions.

"CAISO is lucky to get him, as is a western and international constituency broader even than the one he has served so well at BPA," Cavanagh wrote.

From Enron to CAISO

Mainzer, a San Francisco native, earned degrees from the University of California, Berkeley, and Yale University.

He joined Enron Corp. in the late 1990s, working as an analyst and helping to establish Enron's renewable power desk in Portland, Ore., according to a detailed *biography* posted on CAISO's website.

When Enron collapsed in 2002, after its market manipulation schemes wreaked havoc on California and CAISO during the electricity crisis of 2000/01, Mainzer segued into government service with BPA, headquartered in Portland.

At BPA, he served in a series of increasingly responsible management roles, including deputy administrator, and became acting administrator in 2013. In January 2014, U.S. Secretary of Energy Ernest Moniz named him administrator and CEO.

BPA has been criticized during Mainzer's tenure for increasing rates while struggling to maintain its aging infrastructure. Its assets include 31 hydroelectric projects, including the 7,079-MW Grand Coulee Dam, completed in 1941, and the 2,614-MW Chief Joseph Dam, built in the 1950s.

The agency supplies electricity to 143 electric utilities that serve millions of customers in Washington, Oregon, Idaho, Montana, California, Nevada, Utah and Wyoming.

Elliot Mainzer | © *RTO Insider*

Worried about losing long-term contracts, BPA cut tens of millions of dollars from its annual budget and tried to hold the line on rate hikes.

"Through collaboration with our customers and partners throughout the region, we have worked hard to bend the cost curve and keep base power rates flat," Mainzer said in a statement last year.

Mainzer has "served as administrator during a period of significant industry change," BPA said in its statement Thursday. "In response, he led the development of BPA's 2018-2023 strategic plan, which serves as a roadmap to sustain BPA's financial strength, modernize BPA's assets and system operations, provide competitive power products and services and meet transmission customer needs efficiently and responsively."

Moving from one energy giant to another probably will boost Mainzer's salary from six figures to seven.

Mainzer made about $245,000 in base pay and bonuses as BPA administrator in fiscal year 2018, BPA reported in response to a Freedom of Information Act request last year. Berberich earned nearly $1.5 million in 2017, according to CAISO's most recent Form 990 filing as a nonprofit organization with the Internal Revenue Service.

Berberich plans to remain in Folsom through October to help with the changeover, CAISO said. ■

CAISO/West News

FERC Ends Idaho Power MBRA Probe

Utility Made Convincing Case, Commission Says

By Hudson Sangree

FERC last week found that Idaho Power had satisfied the commission's standards for market-based rate authority and terminated a Section 206 proceeding it had ordered last September to find out if the utility was exercising market power in its balancing authority area (*ER10-2126*).

The proceeding was meant to determine if Idaho Power could continue charging market-based rates in its BAA.

The company's market-power analysis, initially submitted in June 2019, had passed the pivotal supplier and wholesale market share screens in the Avista, Bonneville Power Administration, Nevada Power, NorthWestern Corp., PacifiCorp-East and PacifiCorp-West BAAs and in CAISO's Energy Imbalance Market. But it failed the wholesale market share indicative screen in one season in its own BAA.

Based on the results, FERC ordered Idaho Power to show cause within 60 days why the commission should not revoke the company's market-based rate authority in its BAA.

Responding in November, Idaho Power said its updated market power analysis, which included a delivered price test (DPT), rebutted the presumption of horizontal market power in its BAA.

"As the commission has previously explained, the DPT analysis identifies potential suppliers based on market prices, input costs and transmission availability and calculates each supplier's economic capacity and available economic capacity for each season/load level," FERC said. "The results of the DPT are used for pivotal supplier, market share and market concentration analyses."

Lower Salmon Dam | *Idaho Power*

The DPT calculates market concentration using the Hirschman-Herfindahl Index (HHI). "An HHI of less than 2,500 in the relevant market for all season/load levels, in combination with a demonstration that the applicants are not pivotal and do not possess more than a 20% market share in any of the season/load levels, would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from interveners," FERC explained.

Under the available economic capacity measure, which factors the utility's own load into the calculation, Idaho Power's HHI score was less than 2,500 in all 10 season/load levels. But under the economic capacity measure, its HHI exceeded 2,500 in all 10 season/load levels and "thus Idaho Power fails the market concentration test in every season/load level," FERC said.

However, FERC noted its prior rulings had found that "failure of either the economic capacity or available economic capacity analyses does not result in an automatic failure of the test as a whole. The commission weighs the results of the economic capacity and the available economic capacity analyses and considers the arguments of the parties."

"As the commission explained in Order No. 697: 'In markets where utilities retain significant native load obligations, an analysis of available economic capacity may more accurately assess an individual seller's competitiveness, as well as the overall competitiveness of a market, because available economic capacity recognizes the native load obligations of the sellers," FERC wrote. "On the other hand, in markets where the sellers have been predominantly relieved of their native load obligations, an analysis of economic capacity may more accurately reflect market conditions and a seller's relative size in the market.'"

Given Idaho Power's native load obligations, FERC found the available economic capacity measure — under which its HHI score was consistently less than 2,500 — more accurately reflected conditions in Idaho Power's BAA.

"Based on the above discussion, there is no further need for the Section 206 proceeding instituted in Docket No. EL19-87-000," FERC said. "Accordingly, we will terminate this Section 206 proceeding." ■

ERCOT News

New CenterPoint CEO Promises to 'Simplify the Story'

OGE Earnings Down amid 'Challenging Times'

By Tom Kleckner

A month into his new job, CenterPoint Energy CEO David Lesar said in his first quarterly earnings call with financial analysts last week that the company will "simplify the story" as it attempts to overcome recent bad news.

The former Halliburton CEO said CenterPoint would focus on cost management, rebuilding regulatory relationships, evaluating options for its Enable Midstream Partners with OGE Energy and properly aligning its businesses. The Texas Public Utility Commission in February *approved* a settlement that cut the company's proposed rate increase for its Houston Electric utility from $161 million to $13 million.

Days before the earnings call Thursday, CenterPoint *announced* it was immediately merging Houston Electric and Indiana Electric into one organization, saying "the alignment of CenterPoint Energy's generation, transmission, distribution and engineering areas into one organization" will improve efficiency, operations and reliability.

"When we say 'simplify the story,' as I sort of look back at how we've communicated with shareholders over the past several years, we really have not had a consistent message," Lesar said during the call. "We've had a relatively complicated story. We've had a lot of [mergers and acquisitions]. We've had regulated versus nonregulated.

"A simple message to shareholders consistently executed quarter after quarter will, I think, help regain confidence that shareholders have in us. … Give me some time. Thirty days is not enough time to give you a complete answer, but we're definitely headed in that direction," he said.

CenterPoint CEO David Lesar | *CenterPoint Energy*

The road will be a steep one, as CenterPoint *reported* second-quarter earnings of $59 million ($0.11/diluted share), driven by customer growth, rate relief and "disciplined" operations and maintenance management. A year ago, the company delivered quarterly earnings of $165 million ($0.33/diluted share).

Still, that was better than CenterPoint's first-quarter report, when it took a $1.2 billion loss after writing off $1.6 billion in losses from Enable. (See *Enable Losses Slam CenterPoint, OGE Energy*.)

CenterPoint's stock price closed Friday at $20.41, up $1.36 (7.1%) from its open before the earnings announcement.

"I believe our share price is too low and trades at an unreasonable discount," Lesar said. "After speaking with many of you in the short time I've been here, I believe I have a better understanding for the reasons why this discount exists. You believe we have let you down, and it's certainly my job to address those issues that concern you as we move forward."

Lesar joined CenterPoint's board of directors in May and is leading a Business Review and Evaluation Committee (BREC) conducting a comprehensive, five-month review of CenterPoint businesses, assets and ownership interest.

"I can clearly tell you that nothing is off the table in the BREC review process," he said.

Lesar replaced interim CEO John Somerhalder in July. Somerhalder replaced Scott Prochazka, who resigned after seven years at the helm in February. (See *Prochazka Steps down as CenterPoint CEO*.)

Lesar left Halliburton in 2018 when he hit the oilfield-service giant's mandatory retirement age of 65 for executives, a policy he helped install.

Asked about his age, Lesar said, "I see myself as 67 going on 50. I've got a lot of energy; I like being a CEO; I like being a leader. I have not set a timeline on my tenure here, but I'll know it, [and] the board will know it, when it's right for me to move on. I'm raring to go."

OGE Survives 'Challenging Times'

A CenterPoint Energy serviceman checks a gas meter. | *CenterPoint Energy*

OGE also *reported* second-quarter earnings on Thursday of $85.9 million ($0.43/diluted share) during what CEO Sean Trauschke called "challenging times." A year ago, the Oklahoma City-based company reported quarterly earnings of $100.2 million ($0.50/diluted share).

Earnings adjusted for nonrecurring costs came in at 51 cents/share, beating analysts' expectations of 49 cents.

The ongoing earnings exclude a non-cash charge of $780 million associated with OGE's impaired investment in Enable. The natural gas midstream company contributed $19 million to OGE's net income and $18 million in cash distributions, down from last year's second quarter of $27 million and $35 million, respectively.

"When we created Enable, our goal was to turn it into a standalone entity. From that perspective, it has worked very well," Trauschke said. "We are always evaluating the value of all of our assets, including Enable. We're not going to talk publicly about strategic alternatives, because that does not help increase value."

Like many utilities, OGE subsidiary Oklahoma Gas & Electric has seen its energy usage shift from commercial and industrial consumers to residential during the COVID-19 pandemic. Weather-adjusted residential sales were up 2.3% in the first six months of 2020, while commercial and industrial were both down, 5.6% and 7.6%, respectively. Total weather-adjusted sales are approaching pre-COVID 19 levels but still down 3.2% through June.

OGE's stock price gained 31 cents after the announcement, finishing the week at $33.28. ■

ERCOT News

Vistra Q2 Cash Flow up 30% from 2019

The company formerly known as Vistra Energy — Vistra Corp. as of July 2 — boosted its second-quarter cash flow by 30% over 2019 and told financial analysts Wednesday that the best may be yet to come.

Vistra *delivered* earnings before interest, taxes, depreciation and amortization of (EBITDA) of $929 million, based on net income of $164 million. The company had an EBITDA of $717 million and net income of $354 million during last year's second quarter.

Vistra uses adjusted EBITDA as a measure of performance, saying it improves visibility to both net income prepared in accordance with GAAP and adjusted EBITDA.

CEO Curt Morgan reminded analysts during a conference call that "much of the Texas summer shows its teeth in August and September." He noted that while Vistra's generating subsidiary, Luminant, has not yet been able to take advantage of scarcity prices in the ERCOT market, last August saw 72 15-minute intervals over $1,000/MWh and 12 intervals reaching the $9,000/MWh cap.

"All it takes is one week of hot temperatures and either low wind output or an unplanned outage for scarcity pricing to materialize," Morgan said.

At the same time, he warned investors about EPA's recent regulatory revisions for utilities' disposal of coal ash.

"Our evaluation suggests there are several coal plants, especially in PJM, that are under pressure due to this rulemaking," Morgan said.

Luminant's Odessa-Ector gas plant stands ready for possible scarcity pricing later this summer. | *Luminant*

Vistra's share price lost 50 cents during the day, closing at $18.26 on the New York Stock Exchange. ■

— Tom Kleckner

ISO-NE News

NEPOOL Reviews 'Future Grid' Study Requests

Stakeholders also Briefed on OSW Tx Study

By Rich Heidorn Jr.

NEPOOL members are trying to cull and combine nine proposals for the Transition to the Future Grid study that ISO-NE has offered to perform.

ISO-NE CEO Gordon van Welie announced the initiative in March, saying it will give stakeholders information needed to plan transmission and market designs to achieve decarbonization goals. (See *ISO-NE Study to Chart Transition to Future Grid*.)

Representatives of each stakeholder group gave brief descriptions of their proposals and answered questions during a joint meeting of the NEPOOL Markets and Reliability committees Aug. 4.

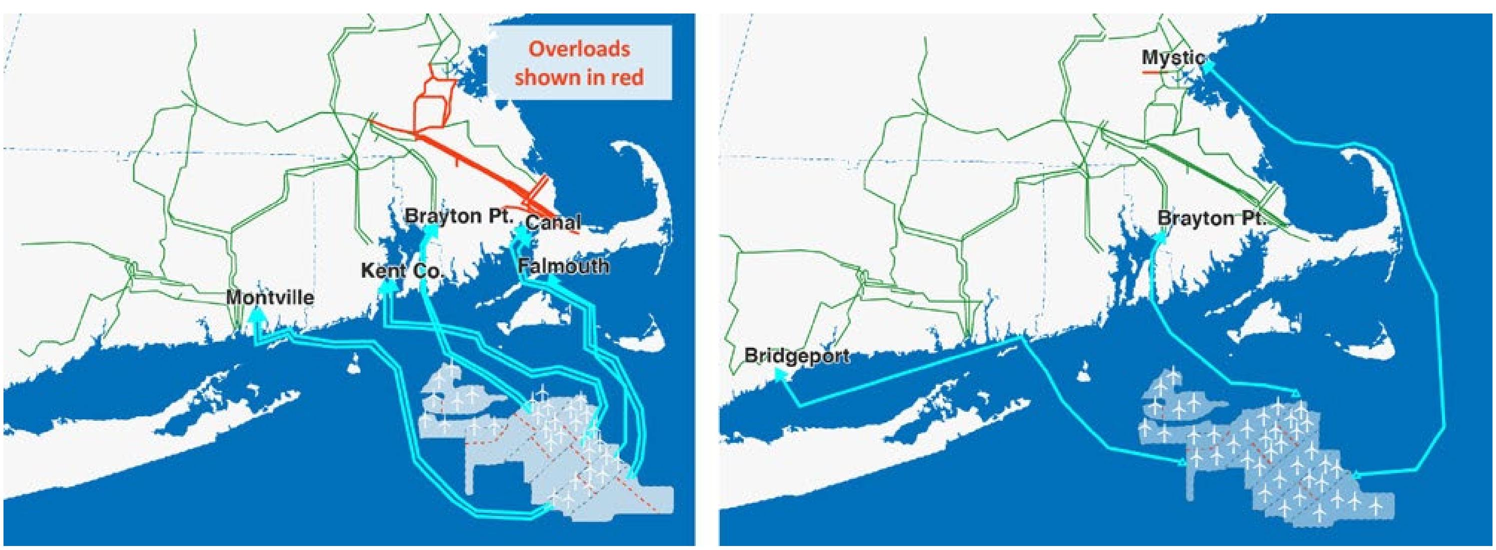
In addition, Ben D'Antonio, counsel for the New England States Committee on Electricity, described NESCOE's *suggestion* that ISO-NE build on the *Pathway Scenario* developed by the *Northeastern States for Coordinated Air Use Management* (NESCAUM) for achieving economy-wide carbon reductions. It assumes that at least 1,000 MW of clean energy resources will be added annually for the next several decades. NESCOE said the Pathway Scenario could be included in energy market modeling to generate hourly dispatch patterns, examine system operating characteristics and requirements and analyze transmission.

Day Pitney attorney Eric Runge presented a *summary* of the nine other proposals:

- Eversource Energy asked for loss-of-load expectations (LOLE) and other reliability metrics, market prices, total cost to load, a description of how the supply mix could develop under current market rules and a qualitative assessment of how likely it is for such a supply mix to develop. It suggested three scenarios for meeting 80% economy-wide emission reductions by 2050: a mixed portfolio, a high offshore wind portfolio and a high solar portfolio. Eversource also made a second request to identify total installed nameplate capacity of a future system where LOLE meets the NPCC standard of one day in 10 years with no renewables built with out-of-market contracts clearing as new in the primary or substitution auctions.
- National Grid asked how bi-directional controllable transmission with Quebec and other neighbors would impact emissions, LMPs and the use and spillage of intermittent resources. It also wants to identify transmission upgrades needed for a fully decarbonized economy and determine whether markets under high renewable/storage penetration cases would provide sufficient revenues to cover resources' capital and operations and maintenance (O&M) costs.
- Energy Market Advisors *said* the RTO should look at the cost, operational and resource adequacy implications of the two options available to new resources addressing state policy objectives: those using capacity network resource interconnection service (CNRIS) and participating in the capacity, energy and ancillary service markets and those using network resource interconnection service (NRIS) and participating in only the energy and ancillary service markets. If policy resources cannot get a capacity service obligation through the forward capacity auction due to the minimum offer price rule or the Competitive Auctions with Sponsored Policy Resources (CASPR) test price, or if the cost of a CNRIS is too high, EMA said that "NRIS may well become the preferred outcome."
- FirstLight Power said that to avoid understating potential reliability problems, the base scenarios should not assume significant new electric storage entry. It would add new

Pathways Scenario: Resource Mix (MW)	2035	2040
Combustion Turbine	1,150	1,500
Combined Cycle Gas Turbine	13,750	15,000
Biomass	Same as Today	
Nuclear		
Hydro		
Onshore Wind	1,750	1,300
Rooftop PV	11,500	12,500
Ground-mounted PV	9,000	15,000
Offshore Wind Fixed	7,000	8,000
Offshore Wind Floating	2,500	8,500

The New England States Committee on Electricity suggested ISO-NE build on the Pathway Scenario developed by the Northeastern States for Coordinated Air Use Management for achieving economy-wide carbon reductions. | *NESCOE*

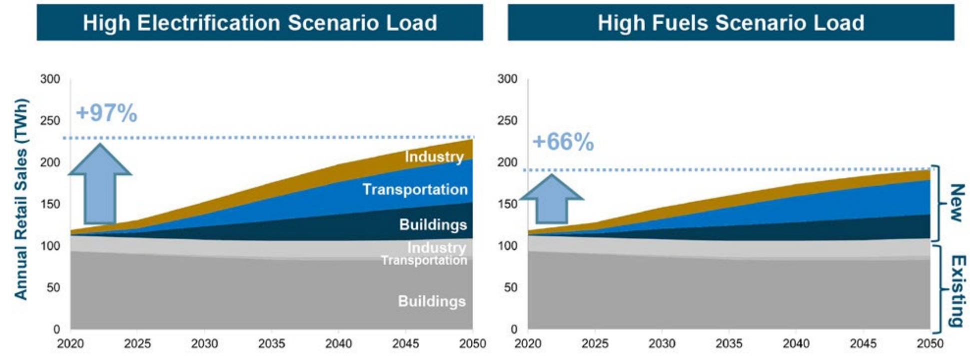


Current generator lead line approach (left) vs. planned offshore-grid approach (right) | *The Brattle Group*

ISO-NE News

electric storage based on as-modelled market prices, considering round-trip efficiency and variable O&M costs.

- NextEra Energy and Dominion Energy made a joint request to determine how the loss of the NextEra's Seabrook and Dominion's Millstone nuclear power plants would impact market prices, system operations and state RPS targets and decarbonization goals.
- American Petroleum Institute asked for a study on how the future grid will balance policy goals with other reliability, affordability and energy access objectives. API cited previous studies and reports by ISO-NE that it said demonstrate "that natural gas infrastructure can further economic and reliability objectives in the region."
- Multisector Group A (Acadia Center, Advanced Energy Economy, Brookfield Renewables, Conservation Law Foundation, Energy New England, Natural Resource Defense Council and PowerOptions) asked for an update and extension of the Planning Advisory Committee's 2016 *economic study on regulation, ramping and reserves* to assess the impact of ramping, regulation and load-following resources as the system decarbonizes.
- Multisector Group B (Advanced Energy Economy, Borrego Solar, Conservation Law Foundation, Energy New England, ENGIE, Natural Resources Defense Council and PowerOptions) seeks a long-term transmission system assessment to identify new transmission investments that could eliminate obstacles to reaching net zero-carbon and that are more economical than upgrades for near-term transmission needs. They also would like an analysis of whether distribution system generation, mobile and stationary storage, increased energy efficiency or flexible demand could reduce the need for new transmission.



Energy+Environmental Economics (E3) and Energy Futures Initiative (EFI) conducted a study that looked at two scenarios for electrification and decarbonization that project electric load will increase by at least 66%. | *E3/EFI*

- Anbaric Development Partners called for identifying an onshore and offshore power system that is carbon-free by 2035, as proposed last month by Democratic presidential candidate Joe Biden. (See *Biden Offers $2 Trillion Climate Plan*.)

The proposals called for study time frames of at least 10 years (EMA) to as long as 2050 (Multisector Groups A and B and Eversource).

Day Pitney will attempt to identify commonalities among the nine proposals before the committees' next joint meeting on *Sept. 1*.

"It's not definite at this point that we'll be the ones conducting the study," ISO-NE spokesman Matt Kakley said via email. "We've offered to do it if stakeholders want us to [and] we're able, but it hasn't yet been decided if that's the direction stakeholders want to go. It's still possible that a consultant could be hired for the work."

E3/EFI Study

The committees also heard a *presentation* on a study on deep decarbonization by Energy+Environmental Economics (E3) and Energy Futures Initiative (EFI) that was funded by Calpine.

The study projects that electricity demand could nearly double over the next three decades with large additions of renewable generation, particularly solar and offshore wind.

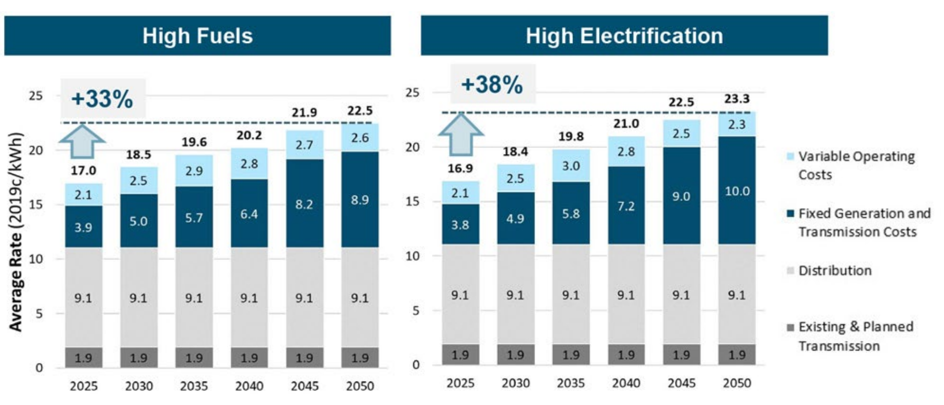
The study included a "High Electrification" case in which 80% of building energy consumption is electricity, with about 230 TWh of annual load in 2050, a 97% increase. It also included a "High Fuels" scenario in which advanced biofuels and hydrogen result in somewhat lower electrification rates and greater reliance on low-carbon fuels, with about 60% of building energy consumption from electricity. It would have a load of 192 TWh by 2050, a 66% increase.

The New England electricity system becomes winter-peaking in the 2030s, and the median gross load peak (net of energy efficiency) is expected to increase from 25 GW in 2019 to 42 to 51 GW by 2050.

The study identifies land and transmission availability as likely constraining factors for new generation development. Its base case estimates that a land area equal to 4% of the region's farmland will be needed for solar generation and 2% of farm and forest land needed for wind.

E3 and EFI said that New England will require 30 to 37 GW of thermal capacity through 2050 under all scenarios studied but that its usage will drop over time, with the capacity factors for gas-fired generation dropping to 10 to 15% by 2050. They expect some form of low-carbon fuel will be available to reduce the carbon intensity.

The study found that cases with the most available solutions have lower costs and lower technology risks. Increasing the availability of land-based wind and solar also reduces costs.



The E3/EFI study projected prices increasing by 38% by 2050, mostly due to new generation and transmission. | *E3/EFI*

ISO-NE News

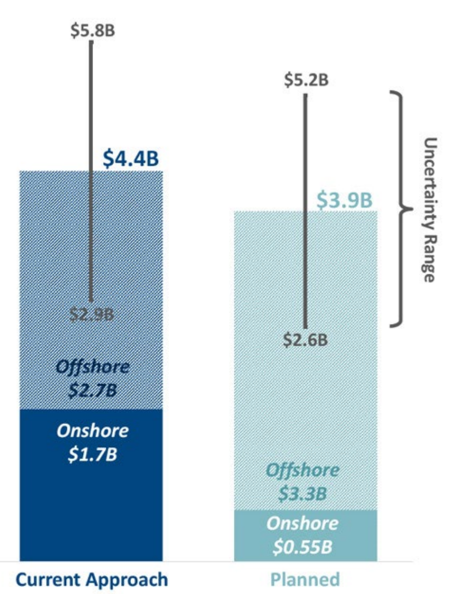
"Firm, low-carbon technologies such as advanced nuclear, [carbon capture and sequestration] or hydrogen could play a significant role," E3 and EFI said.

Average electric rates will increase at a compound annual growth rate of 1.3 to 1.5% by 2050 to fund infrastructure additions, including new generation, transmission upgrades and spur line costs, and a slight increase in variable costs. Average prices are forecast to rise from 17 cents/kWh in 2025 to 23 cents/kWh in 2050 under the high electrification case, an increase of 38%.

Removing all combustion turbines (CTs) and combined cycle plants (CCGTs) increases the cost of achieving a zero-emissions grid by about $19 billion annually relative to a zero-emissions portfolio with zero-carbon fuels (hydrogen or biogas).

In most weeks, wind and solar generation minimizes the need for CTs, CCGTs or steam turbine generation. But when renewable production is low, up to 32 GW of thermal generation could be dispatched for reliability. Building a system with no gas or hydrogen would cause a "significant overbuild" of renewables and storage, resulting in many curtailments during typical weeks, the authors said.

Without upgrades to the region's 345-kV network, the study found enough "headroom" for a combined 800 MW of renewable generation in New Hampshire and Vermont, and 4 GW each for Connecticut, Massachusetts and Rhode Island. There is no headroom for Maine, which has the best onshore wind potential in the region. Offshore wind headroom is estimated at 8 GW.



Comparison of total onshore plus offshore transmission costs in Phase 1 analysis (3,600 MW additional OSW) | *The Brattle Group*

Utility-scale solar could increase to 50% of the projected 2050 peak load without upgrades. Reaching 100% would require 115-kV line upgrades.

Brattle Offshore Wind Study

The committees also heard a presentation on an Anbaric-funded study by *The Brattle Group*, *GE Energy Consulting* and *CHA Consulting* that examined two approaches for developing offshore transmission and associated onshore upgrades to reach New England's offshore wind (OSW) targets.

It concluded that the current approach — with OSW developers competing primarily on cost to develop offshore generation and project-specific generator lead lines — would be more expensive than developing transmission independently from generation. "A planned approach is likely to result in lower costs in both the near- and longer-term, by lowering risks and costs of onshore upgrades and increasing competition for both offshore transmission and generation," the study found.

The study also concluded that a planned approach would make better use of limited onshore points of interconnection, reduce seabed disturbances, increase competition for transmission and generation and reduce transmission upgrade costs.

The study found that the region will need to add more than 1,500 MW of OSW annually to reach the "80% by 2050" decarbonization goals.

Phase 1 of the study focused on 3,600 MW of OSW (including authorized procurements of 1,600 MW in Massachusetts and 1,200 in Connecticut). Phase 2 included an additional 4,800 MW, for a total of about 8,400 MW.

It cited as examples of proactive transmission planning Texas' Competitive Renewable Energy Zones, California's Tehachapi wind, MISO's Multi-Value Projects and several European countries.

Brattle said the existing approach for connecting 2,800 MW of OSW already contracted to Cape Cod will require $131 million to $787 million in onshore transmission upgrades. Continuing the current approach in the next 3,600 MW of procurements could cost up to an additional $1.7 billion in onshore upgrades it said.

The planned approach would increase offshore transmission equipment costs by $600 million ($3.3 billion vs $2.7 billion) but reduce costs of onshore upgrades from $1.7 billion to $550 million, a savings of more than $1.1 billion or 10% for Phase 1.

Among other findings, Brattle said the planned approach would result in:

- A 40% reduction in line losses.
- Increased competition: It cited studies of offshore transmission costs in the U.K. showing that competition among independent offshore transmission owners reduced costs 20-30% compared with generator-owned transmission.
- Fewer system overloads: The study said a scenario using the current planning, with 8.1 GW of generation and five points of interconnection, would have many more system overloads — particularly in Connecticut and the Mystic-North Cambridge-Woburn section of Massachusetts — than a planned system that carried 8.6 GW over nine points of interconnection.
- Lower OSW curtailment: 14% vs. 34% in 2028.
- Increased production cost savings: $619 million in 2028 vs. $564 million for the current process, a difference of $55 million or almost 10%.
- Lower LMPs: Some locations in Rhode Island and Southeastern Massachusetts would face significantly higher LMPs by 2028 under the current approach because of transmission congestion.
- An almost 50% reduction in marine trenching: 831 miles vs. 1,620 miles for Phases 1 and 2.
- Preservation of the option for networked transmission to improve reliability and reduce curtailments from transmission outages: If three 1,200-MW HVDC converter stations were networked offshore, an outage of one line would still allow full power flow in all hours when total generation is less than 2,400 MW, resulting in only 4% of energy curtailed relative to no outages. "Under the current (non-meshed) gen-tie approach, an outage in any one of three lines would [result in a] 33% reduction in delivered energy to the onshore system, causing significantly more curtailments than under a meshed configuration," Brattle said. ■

ISO-NE News

FERC OKs Most of ISO-NE 2nd Storage Compliance

By Michael Kuser

Green Mountain Power's Stafford Hill Solar Farm in Rutland, Vt., was the first in the region to use battery storage to reduce peak demand. | *UVM*

FERC last week accepted most provisions in ISO-NE's second compliance filing for Order 841, which requires RTO market participation rules to recognize the unique physical and operational characteristics of storage resources.

The changes become effective Dec. 3, 2019, with a limited number of revisions becoming effective Jan. 1, 2026, subject to further compliance filings (*ER19-470-004*).

The commission in December found ISO-NE had failed to comply with requirements to account for maximum run time, maximum charge time, state of charge, maximum state of charge and minimum state of charge (collectively, state of charge and duration characteristics) of electric storage resources in the day-ahead market. It required the RTO to modify its participation model through bidding parameters or other means.

FERC in April denied a rehearing request on the same issue. (See *ISO-NE Order 841 Rehearing Request Denied*.) In last week's order, the commission accepted most of ISO-NE's revisions around the issue but found the RTO still didn't go far enough.

"We find that, while ISO-NE's proposed revisions state that it will account for such characteristics in the day-ahead market through bidding parameters or other means, ISO-NE has failed to propose any bidding parameters or other means through which it will do so," the commission said.

"If ISO-NE intends to rely on new bidding parameters, it must define those bidding parameters in its Tariff and explain in its transmittal how those bidding parameters will be incorporated into its day-ahead market engine," the commission said, directing the RTO to file such revisions within one year.

The commission also rejected ISO-NE's response to direction that it file Tariff revisions that apply transmission charges to an electric storage resource when that resource is charging for later resale in wholesale markets and is not providing a service, and to include a basic description of ISO-NE's metering methodology and accounting practices for ESRs.

"We disagree with ISO-NE's statement that electric storage resources will always be providing a service when charging for later resale in the wholesale markets," the commission said. "Specifically, we find that ISO-NE has failed to demonstrate that an electric storage resource that is self-scheduled to charge at a fixed MW quantity is providing a service that warrants exempting its full self-scheduled charging MW from transmission charges."

The commission directed ISO-NE to file within 90 days Tariff revisions specifying that it will not apply transmission charges to ESRs when they are dispatched to withdraw energy to provide voltage support and reactive control, provide operating reserves, provide regulation, balance energy supply and demand on an economic basis or address a reliability concern, but it will apply transmission charges to ESRs when they are not being dispatched to provide one of those tariff-defined services.

The commission also directed the RTO to modify Tariff language that "could effectively allow the host utility to decide whether an electric storage resource may participate in the ISO-NE markets by stating that an electric storage resource cannot qualify to participate if the host utility is unwilling or unable to support the necessary registration, metering and accounting of the electric storage resource. This language may create a barrier to the wholesale participation of electric storage resources and may therefore be inconsistent with Order Nos. 841 and 841-A." ■

ISO-NE News

NEPOOL Reconsiders Forward Clean Energy Market

Participants Committee also Briefed on Carbon Pricing

By Rich Heidorn Jr.

NEPOOL's Participants Committee on Thursday began taking a new look at how it can adapt market rules to reach New England states' decarbonization goals with educational presentations on two potential "pathways": carbon pricing and a forward clean energy market (FCEM).

The pathways discussion — and planning for a parallel "Future Grid" study — resulted from requests by the New England Power Generators Association (NEPGA), New England States Committee on Electricity (NESCOE) and other stakeholders for the region to plot a path toward reaching states' 2050 decarbonization goals. (See *NEPOOL Reviews 'Future Grid' Study Requests*.)

At the March PC meeting, NESCOE Executive Director Heather Hunt said the organization's *request* was intended "to initiate proactive and actionable discussion on the future grid and potential market changes to achieve states' goals other than through the reactionary changes that have been directed by the FERC and driven the region's efforts in past years," according to NEPOOL meeting minutes.

IMAPP Redux?

Carbon pricing and the FCEM were among four long-term proposals considered in detail by stakeholders in the Integrating Markets and Public Policy (IMAPP) initiative in 2016. Carbon pricing foundered because of differing ambitions among the states, with New Hampshire balking at the more ambitious goals of Massachusetts and Connecticut. (See *ISO-NE Two-Tier Auction Proposal Gets FERC Airing*.)

ISO-NE ultimately adopted a two-tiered capacity construct, the Competitive Auctions with Sponsored Policy Resources (CASPR) to prevent consumers from paying twice for the same capacity through both the Forward Capacity Market (FCM) and subsidies for new, state-mandated supply resources.

CASPR is intended to allow state-sponsored resources to enter the FCM while maintaining competitive prices in the Forward Capacity Auction (FCA). In a substitution auction after the primary FCA, existing capacity resources may transfer their obligations to new resources that did not clear in that first stage because of the minimum offer price rule.

The CASPR substitution auction cleared 54 MW in 2019 and none in 2020. That led some observers to label CASPR a failure, with others calling for it to be redesigned. (See *ISO-NE Capacity Prices Hit Record Low* and "CASPR the Ghost," *NEPOOL Markets Committee Briefs: May 12, 2020*.)

ISO-NE CEO Gordon van Welie has urged patience, *telling* the PC in March that CASPR is the "next best solution" if the region can't adopt effective carbon pricing.

"Resource substitution via CASPR will depend on the build-up of economic pressures over time," he said. He acknowledged CASPR's performance thus far "has caused concern among some stakeholders that the transition may not occur swiftly enough, or that the lack of substitution may lead to a costly overbuild, leading to a discussion about alternative market designs or structures."

Forward Clean Energy Market

Kathleen Spees, Brattle Group | *The Brattle Group*

At Thursday's PC meeting, Kathleen Spees of The Brattle Group briefed members on its *FCEM proposal*, which she said could help states achieve their goals without demanding that those goals be uniform. "We developed the Forward Clean Energy Market as one tool that states could use for mobilizing private investment to meet their goals through a competitive market," Brattle said.

The Brattle proposal resulted from a *study* funded by the Conservation Law Foundation, Brookfield Renewable Partners, NextEra Energy Resources and National Grid, and *one* funded by NRG Energy, Spees said.

The proposal acknowledges states' desire to move from a wholesale market that delivers "reliable, low-cost electricity" to one in which the power is also carbon-free, Spees said.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

Brattle's proposed Forward Clean Energy Market would be a centralized auction in which buyers and sellers could voluntarily exchange clean energy attribute credits (CEACs). | *The Brattle Group*

ISO-NE News

The FCEM would be a centralized, three-year forward auction in which buyers and sellers could voluntarily exchange clean energy attribute credits (CEACs) — a product Spees likened to a renewable energy credit.

There are two optional variations: One for a "dynamic" CEAC would award more credits to resources that displace more carbon emissions, which would benefit batteries "and focus incentives toward achieving more carbon abatement faster," Brattle said.

A second option would allow buyers to register a preference for "targeted" resource types to meet carve-outs for preferred technologies such as storage or offshore wind.

The FCEM would assign most fundamentals-based and asset-specific risks to sellers, with features to mitigate regulatory risks and support financeability:

- a multiyear commitment period of about seven to 12 years to lock in prices for new resources;
- a multiyear forward period to support development and financing of new resources;
- a sloped demand curve to reduce year-to-year price volatility and improve revenue certainty; and
- the ability for states to make commitments to rely on the market for a minimum time frame and quantity to ensure confidence in the construct.

Spees indicated a willingness to discuss a forward period shorter than three years, which could benefit some renewable developers. But she noted that some clean resources such as offshore wind may also have longer development time frames. She recommended that the FCM and FCEM both be conducted at the same forward period to minimize clearing risks for new resources that seek financing.

Brattle said its simulations estimated that FCEM could save customers $3.60/MWh — or $4.5 billion over 10 years — compared to states' current practices for bringing clean resources and storage online, including competitive solicitations.

Spees said the FCEM offers several benefits over carbon pricing and traditional RECs.

Carbon pricing maximizes benefits if implemented regionally and economy-wide, which may not be politically feasible in the near term; carbon prices acceptable to all states would likely be too low to achieve the carbon-reduction goals. The FCEM, by contrast, would not require states, cities or companies to agree on a common price or policy goal: States and customers pay to meet their own goals with no cost-shifting to nonparticipants.

Brattle says traditional RECs offer flat incentives over every hour and incentives to offer at negative energy prices during excess energy hours when displacing other clean supply.

"Dynamic" CEACs would scale payments in proportion to marginal CO_2 displacement by time and location, incenting the production of clean energy when and where it is most effective in reducing emissions, Spees said. There would be no incentive to offer at negative prices.

Spees said she was uncertain whether the plan would be subject to FERC jurisdiction or outside it like the REC market and the Regional Greenhouse Gas Initiative. Either way, she said, "it's critical that states have control over their participation. States were very clear when we went through the IMAPP that they want that flexibility."

Carbon Pricing


Joe Cavicchi, Analysis Group | *Analysis Group*

Joe Cavicchi of Analysis Group also gave a *presentation* on the NEPGA-funded carbon pricing study it released in June.

Cavicchi began his presentation with a look at Western Europe, where carbon spot prices, which he said had been ineffectual at about 5 euros/metric ton in 2017 ($5.89), have generally traded between 20 and 25 euros since 2018 ($23.57 to $29.47).

Analysis Group's study concluded that New England needs a CO_2 price of $25 to $35/short ton by 2025, rising to $55 to $70 by 2030, to meet states' carbon emissions goals. (See *Study: $25 Carbon Price Needed to Meet Goals*.)

Cavicchi said a multisector price on carbon could help the transformation to electrification, allowing "a more accurate assessment of the trade-offs when assessing electricity as a fuel for transportation and heating as opposed to fossil fuels."

It also would allow technology-neutral competition among existing and new zero-emission resources in the electric sector, incentivizing cost reductions and innovation while reducing the need for future state-directed investments. It would additionally reduce the risk of stranded investments that can result when the costs of power from new technologies drop below long-term contract prices.

The study assumed light-duty electric vehicle penetration of 25% in 2025, 60% in 2030 and 90% in 2035. Similarly, it assumed 25% of homes heating with oil, propane or natural gas would switch to electric by 2025, rising to 50% by 2030 and 75% in 2035.

Although a carbon price would increase wholesale power prices, it would not increase consumer costs materially if states rebate the carbon revenues, the study said.

Next Steps

The PC next month will receive education on energy-only markets, such as ERCOT, and alternative approaches to the region's existing reliance on the FCM for resource adequacy.

The committee expects to begin discussing the pros and cons of the potential solutions in October.

Consent Agenda

Earlier in the meeting, the PC approved the following on the consent agenda:

- The amended and restated Services Agreement between NEPOOL and ISO-NE reflecting the evolution in the roles of ISO-NE, NEPOOL and the NEPOOL Generation Information System Administrator, as recommended by the Markets Committee at its July 14-15 meeting.
- Revisions to metering requirements for DC-coupled assets: Manual M-28 (Market Rule 1 Accounting) and Manual M-RPA (Registration and Performance Auditing), as recommended by the MC in July.
- Revisions to OP-18 (Metering and Telemetering Criteria), which adds requirements for DC-coupled assets, as recommended by the Reliability Committee at its June 16 meeting.
- Revisions to Planning Procedure No. 5-1 (Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans) in response to the significant increase of proposed plan applications and generator notification forms being processed monthly. Submittals will be required 10 business days before the monthly RC meeting date. Generator application forms have been updated to enable bulk review and summarization, and information regarding the storage component of co-located facilities will be collected to enable improved summarization. The change was recommended by the RC in June. ■

MISO News

MISO Prolongs Terms on Midwest-South Tx Limit

By Amanda Durish Cook

The MISO stakeholder community appears to support the RTO's plan to extend the current arrangement on transmission flows between its Midwest and South regions.

Jeremiah Doner, MISO's director of seams coordination, told stakeholders during a Market Subcommittee teleconference Thursday that the grid operator will file by Nov. 1 to add two years to a settlement agreement with SPP and six other parties. MISO agreed to the settlement, which manages the regional directional flows over SPP's system to connect the Midwest and South regions, with the seven parties in 2016.

Doner said the agreement's extension was generally well received by stakeholders.

But not all were happy.

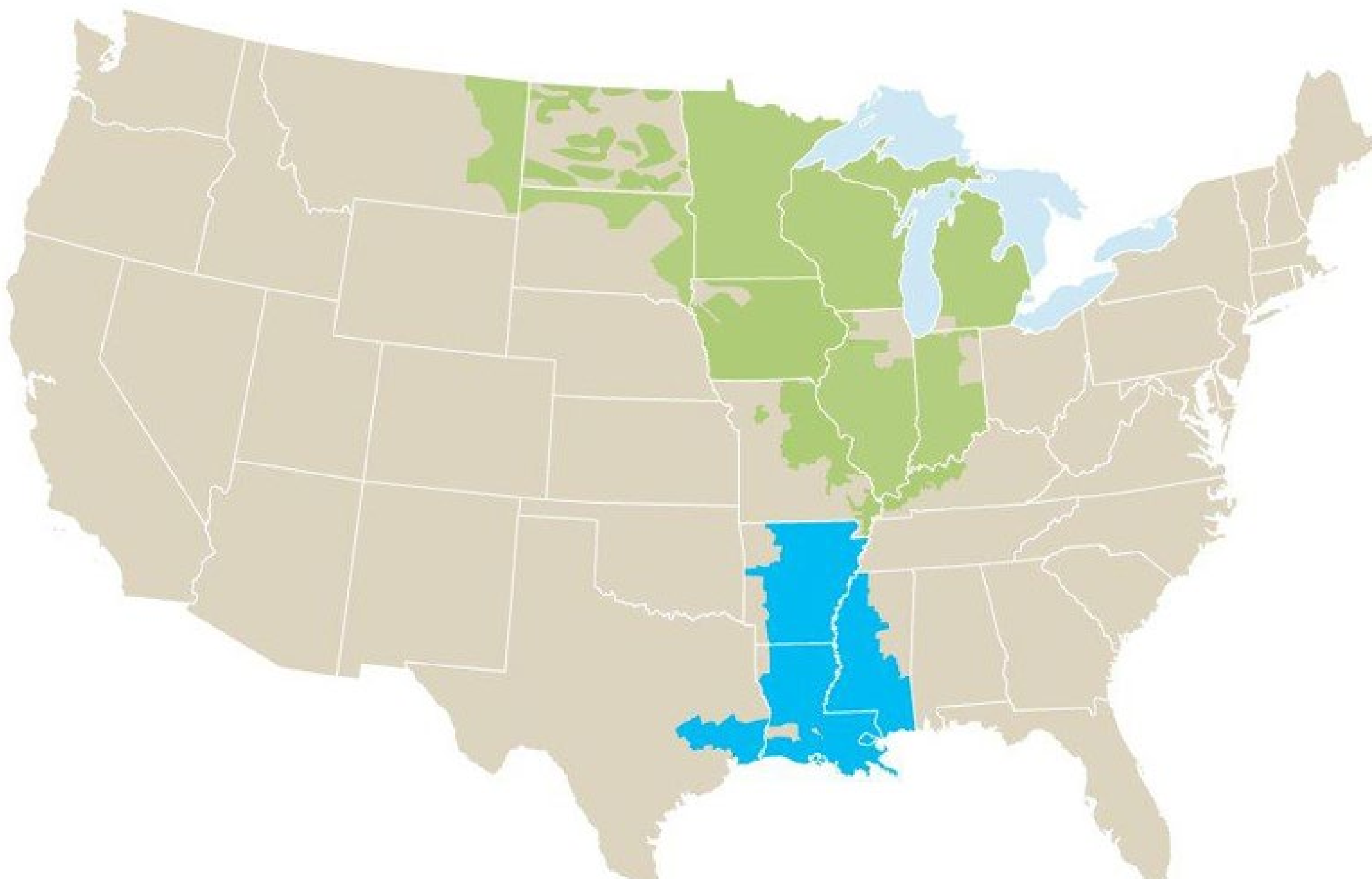
MidAmerican Energy's Greg Schaefer said he was disappointed because his company's location in Iowa means it is shouldering a heavy financial burden for MISO's use of SPP's system above its 1,000-MW contract path.

"All the costs are being loaded onto a relatively small number of parties," Schaefer said. "It's not surprising that there is a consensus here."

MISO's payments to the other parties for regional flows above the contract path are recovered from its market participants using a special rate schedule, which increasingly has put emphasis on a flow-based beneficiary allocation over a load ratio calculation. The current calculation is 90% flow-based and 10% load-based, which will continue into 2023. (See *MISO Seeks Extension on Midwest-South Tx Limit*.)

The 2016 agreement can be terminated by any party with a year's notice beginning Jan. 31, 2021. Without an extension or alternative solution, MISO's flows would be limited to its original 1,000-MW contract path in either direction. The agreement limits MISO to 3,000 MW of flows in the north-to-south direction and 2,500 MW in the other direction.

MISO has said a two-year extension of the original terms will buy time for it, SPP and the other parties to explore eventually reopening the agreement's terms. MISO has also said it may revisit the idea of constructing new transmission capacity to supplant the agreement. (See "No Midwest-South Tx Solution this Year," *Price Tag Rising for MTEP 20*.) ■



MISO Midwest and South | *MISO*

MISO News

FERC Orders Final Revision for MISO Storage Compliance

By Amanda Durish Cook

MISO's participation model for electric storage resources needs a final edit before FERC declares the grid operator fully compliant with Order 841, the commission said last week.

FERC on Aug. 3 ordered MISO to remove or defend its requirement that distribution utilities and load-serving entities report real-time grid injections and withdrawals. FERC said MISO couldn't impose reporting obligations on distribution utilities or LSEs because those companies aren't party to its new *pro forma* storage participation *agreement*. FERC said MISO might require data reporting from companies that might not have "any relationship" with the grid operator (*ER19-465*).

"This reporting requirement is also unnecessary because MISO proposes to require the electric storage resource to report the same information," the commission said.

FERC said it otherwise approved of MISO's plan to make market participants responsible for meter installation, ownership, meter-data quality and "periodic testing of metering and related equipment." The commission also found no problem with MISO's requirement that storage owners report hourly real-time injections and withdrawal volumes at commercial pricing nodes or to estimate hourly injections and withdrawals if the energy storage resources don't have a meter at a node.

FERC in November found that MISO's model largely complied with Order 841 but lacked detail about metering and accounting practices for distribution-connected and behind-the-meter ESRs. (See *Storage Plans Clear FERC with Conditions*.)

FERC's latest order, however, rejected a group of Midwestern transmission-dependent utilities' ask that MISO's new *pro forma* agreement not be applicable to ESRs with on-site generation.

"Order No. 841 defines an 'electric storage resource' as a resource that can receive energy from the grid and store it for later injection back onto the grid. This definition does not specifically include or exclude, or otherwise discuss, electric storage resources that have on-site generation," FERC said.

The commission also declined the Midwestern group's request that it order MISO to make storage resources pay the Multi-Value Project (MVP) transmission charge. The charge funds the grid operator's 2011 MVP transmission expansion portfolio and is allocated on a load-ratio basis to wholesale energy purchases. FERC agreed with MISO that storage resources should be exempted from the charge "because they do not consume energy as an end-use."

"Even if the Tariff language and rate structure that existed prior to Order No. 841 allowed the assessment of the MVP charge to [ESRs] based on their monthly net actual energy withdrawals in a manner analogous to load, [ESRs] would still largely avoid the MVP charge because their withdrawals from charging would be mostly offset or netted by their discharging injections," the commission wrote.

Finally, FERC accepted MISO's explanation that ESRs should be excluded from qualifying as fast-start resources. The ISO said storage resources, as "offline energy-limited resources," would "depress prices because they may be less feasible and less available due to state-of-charge management by the market participant."

MISO has until mid-2022 to implement its ESR participation plan, as it will first have to build a new market platform. ■

| Connexus Energy

MISO News

MISO Investigating LMR Availability Problem

By Amanda Durish Cook

MISO last week said it will begin hunting for solutions to mitigate "significant gaps" between load-modifying resources (LMRs) that clear capacity auctions and what actually shows up to help mitigate emergencies.

The RTO acknowledged during a Resource Adequacy Subcommittee teleconference Wednesday that it had a problem with the amount of LMR-accredited values and what is listed as available to allay demand during summer peak times.

Market Design Adviser Dustin Grethen said that when MISO hit its summer peak in July 2019, 6 GW of LMRs were listed as available, though 11.5 GW cleared the Planning Resource Auction a few months earlier.

Grethen said some of the availability issues result from LMR outages, fear of penalties by overstating load-reducing capability, overly generous LMRs accreditation, voluntary self-deployment or difficulties using the RTO's availability reporting tool, the MISO Communication System (MCS). Some LMRs that double as emergency demand response enter availability through a separate RTO tool and not the MCS, he said.

Even those reasons cannot explain all the widespread unavailability, Grethen said. He promised MISO would investigate why some LMRs are no-shows after clearing the capacity auction.

Customized Energy Solutions' Ted Kuhn suggested the grid operator start by checking the MCS' availability against the metered data LMRs are required to provide.

MISO's Little Rock headquarters | *MISO*

The LMR availability gap is part of MISO's ongoing resource availability and need suite of market improvements. The RTO is still gauging which combination of new resource adequacy and capacity market rules it might adopt to reduce the number of maximum-generation emergency events it declares. (See *MISO Closer to Seasonal Capacity, Reliability Reqs*.)

As part of that, the grid operator will now scrutinize the actual availability of conventional generators and for what they're accredited. Planning Adviser Davey Lopez said MISO's planning reserve margin requirement is likely understated because it doesn't model real-world generation outage scenarios.

Pandemic Still Muddying Forecasts

MISO is still calculating emergency resources' response during its most recent emergency event on July 7. (See *Max Gen Event Managed Efficiently, MISO Says*.)

Executive Director of Market Operations Shawn McFarlane said MISO didn't have to resort to LMRs that day. He said the peak would have been higher had not thunderstorms popped up in the northern part of the footprint.

McFarlane also said the pandemic continues to complicate load forecasting, as air conditioning load is likely skewed to more residential use this year than in others because of customers working from home.

"We think there's some offsetting things that made it very hard to predict summer peak," he said.

Despite that, McFarlane called the event "one of the most orderly max gens I've seen," as MISO responded quickly and committed more resources appropriately.

MISO President Clair Moeller said not much has changed in the RTO's *modus operandi* after the pandemic's announcement.

"The risk profile doesn't seem to be changing much," Moeller said during an Informational Forum on July 21. "The good news is the operational impacts of the pandemic are manageable … and we don't expect that to change."

Moeller said load "crept back up" in July and is now about 5% less than its normal load average.

"We're still learning how to forecast in this new environment," he said. ■

MISO News

MISO Revisits Scarcity Pricing Rethink

By Amanda Durish Cook

MISO is once again evaluating the effectiveness of the rules behind its scarcity pricing just three years after shelving a similar effort.

Market Design Adviser Michaela Flagg said the RTO will analyze whether to up its value of lost load (VOLL) and change the shape of the operating reserve demand curve. It would likely file revisions in the second quarter of 2021.

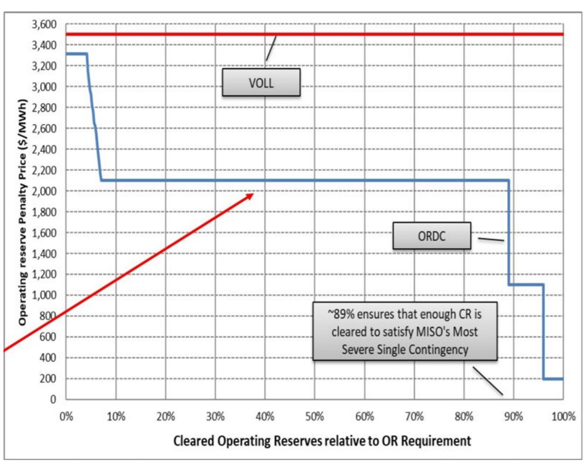
"Shortage conditions are not appropriately priced," she told stakeholders at during a Market Subcommittee teleconference Thursday.

MISO has said it needs to re-evaluate its scarcity and emergency pricing and is exploring a different cost structure under its yearslong resource availability and need (RAN) project. Shortage and emergency pricing has generally been inefficiently low, the grid operator says. (See *MISO Exploring Emergency Pricing, Forward Market*.)

The current $3,500/MWh VOLL could be understating the value of involuntary load shedding, and the administratively set price doesn't account for congestion, generation losses or other reserve shortages, MISO contends.

Principal Adviser of Market Design Michael Robinson said MISO first set the VOLL in 2009 based on the class of customers who value uninterrupted electrical service the least and consider shedding load at that price.

"It's a little bit dated here," he said. "We established the price that people weren't willing to pay, and that's $3.50/kWh. Now, they're not going to shed hospitals; they're not going to shed entities that value uninterrupted electric energy service. They're going to shed customers that value it less ... and prefer interruption to those rates. That was the thinking back then."



MISO's operating reserve demand curve stays at $2,100/MWh for most scarcity conditions. | *MISO*

MISO's Independent Market Monitor recommended it ratchet up the VOLL three years ago when it was implementing FERC Order 831, which required the use of a $1,000/MWh soft cap and $2,000/MWh hard cap on energy prices. (See *MISO, IMM Differ over Scarcity Pricing Changes*.) Ultimately, MISO didn't pursue a higher VOLL.

The RTO must consider the consequences to different market segments when adjusting the VOLL, Robinson said, whether that be inconvenience or ruining leisure, to property damage or spoilage of food and other perishables. He said residential and light industrial customers typically suffer the least from load shedding.

Robinson said MISO has never shed firm load because of a capacity emergency since the rollout of the wholesale markets, although it has experienced local load shedding because of transmission outages.

MISO could use a price index or economic research to update the VOLL, Robinson said. "There are a lot of potential approaches."

However, while MISO could perform its own analysis of end-use customers to establish a price, it would likely be prohibitively expensive and too labor-intensive, he said.

WPPI Energy economist Valy Goepfrich suggested MISO research the retail rates of customers getting paid to interrupt their load. "It might be interesting what you find," she said.

Monitor David Patton said the understated VOLL means MISO generation still exports to neighboring PJM during shortage conditions. "It creates a mess when you have two [RTOs] valuing electricity at very different levels. ... We view this as the No. 1 item for achieving MISO's RAN initiative," he said.

Additionally, MISO's operating reserve demand curve (ORDC) isn't nuanced enough to "differentiate shortage severities, especially above minimum requirements," Flagg said. "A very large portion of the curve is flat."

The ORDC curve, based on the VOLL, begins at $3,300/MWh, dropping to $2,100/MWh when the RTO clears 8% of its requirement level. At 89%, the level falls to the original $1,100, remaining there until 96% or more of the requirement is cleared, when the curve flattens at $200.

MISO is also reassessing a five-year-old Monitor recommendation that the RTO stop allowing offline resources to set prices. Currently, offline fast-start resources can set extended LMPs during a shortage. The Monitor contends that allowing offline units to set prices artificially suppresses scarcity prices.

Emergency Pricing Fixes on the Way

MISO Research and Development Adviser Yonghong Chen said the RTO will most likely file with FERC before the end of the year to improve its emergency pricing. Chen said that for now, MISO is pursuing a few "simple" fixes that have high impact:

- expanding extended LMP eligibility to allow online units with start-up times of four hours or less to set prices during emergencies and emergency alerts;
- taking the Monitor's advice to set an administrative emergency offer floor for emergency resources that respond without an offer; and
- updating the emergency pricing structure to reflect the costs of managing congestion on the regional directional transfer limit linking MISO Midwest and South.

Chen said MISO will work on a conceptual design and a benefits evaluation in the fall.

Restoration Energy Pricing Approved

Meanwhile, FERC last month authorized MISO's new plan to compensate generators that re-energize the grid following a blackout (*ER20-1673*).

MISO's compensation for restoration energy relies on last-submitted offers before a blackout as a starting point for pricing, resulting in unique costs based on resource. The RTO will allow for the recovery of start-up costs, emergency purchases and resource-specific energy costs. It would also include recovery for any unusual costs incurred during operation, provided they can be verified by the Monitor. It would also accept after-the-fact updates of offers. (See "Restoration Energy Design Nears Completion," *MISO Market Subcommittee Briefs: Dec. 3, 2019*.) ■

MISO News

WEC Manages Modest Increase in Q2 Earnings

By Amanda Durish Cook

WEC Energy Group managed a 2-cent earnings per share improvement in the second quarter over last year, with several factors offsetting the COVID-19 pandemic's economic consequences.

The Wisconsin utility *recorded* net income of $241.6 million ($0.76/share) compared to $235.7 million ($0.74/share) in the same period in 2019.

"Despite the negative margin impact in this year's second quarter related to the pandemic, we were still able to achieve quarter-over-quarter earnings-per-share growth," WEC CFO Xia Liu said during an Aug. 4 earnings call. She said "significantly warmer-than-normal weather," an increase in the return on equity for WEC's American Transmission Co. and execution of the utility's five-year capital spending plan helped blunt the impacts of lower energy demand.

"We remain optimistic and confident in our ability to create value despite the challenges presented by the pandemic," Executive Chairman Gale Klappa said.

WEC said it has about 11,000 more electric and 27,000 more natural gas customers compared to a year ago. The utility serves 4.5 million customers in Wisconsin, Illinois, Michigan and Minnesota. Compared to the second quarter of 2019, residential electricity sales were up 17.1%, small commercial industrial electric sales were down 8.6% and large commercial and industrial sales were down 12.9%.

WEC predicts continued economic recovery through the end of the year; however, COO Scott Lauber said the company has a plan in place if recovery proves more sluggish.

"We are prepared if the level of recovery would drop back to what we saw in the second quarter. We estimate that the additional impact to the pre-tax margin would be approximately $10 million to $15 million. We believe we could absorb this margin compression through efficiency measures already in place," he said.

Lauber also said that the Wisconsin Public Service Commission's April *decision* to allow utilities to track and defer uncollectible expenses and pandemic-related costs helps the company's bottom line.

Klappa said WEC's $15 billion capital investment plan from 2020 through 2024 remains unchanged.

"We have ample liquidity and no need to issue new equity," he told investors.

Klappa said WEC's *announcement* late last month that it will pay $235 million to acquire an 85% ownership interest in the 155-MW Tatanka Ridge wind farm in South Dakota is part of the capital plan.

However, he reported that construction at the 300-MW Thunderhead Wind Farm in Nebraska hit a snag that will likely delay it "several months" beyond its 2020 year-end in service date. WEC will have a 90% stake in the project.

"We now project a several-month delay because the local utility has paused construction of a substation that's needed to connect the Thunderhead project to the transmission network. We continue to work with all the relevant parties to minimize the delay," Klappa said.

CEO Kevin Fletcher said WEC still has designs on more utility-scale solar generation. He said work continues on two solar projects totaling 200 MW for Wisconsin Public Service.

In addition, subsidiary We Energies will still invest — along with Madison Gas and Electric — in construction of the *delayed* $194.9 million Badger Hollow II solar farm, which is now expected to be in service by the end of 2022. ■

Tatanka Ridge wind farm | *Acciona*

NYISO News

New York Ponders Planning an Offshore Grid

Study Finds Savings in 'Planned' Tx

By Michael Kuser

A new *study* by The Brattle Group estimates New York would save $500 million through a planned transmission strategy for its next 7,200 MW of offshore wind versus the generator lead line (GLL) approach.

The new study for Anbaric Development Partners reaches similar conclusions to *one* Brattle did for the company in May on the potential benefits of planned and networked transmission development for southern New England. (See *Brattle Study Highlights Benefits of Offshore Grid*.)

In the New York study, Brattle estimated onshore upgrade costs of $500 million under a planned approach, compared to $2 billion for GLLs, a savings of $1.5 billion. That would be partially offset by increased offshore transmission costs for the planned approach — $6.1 billion vs. $5.1 billion for GLLs — primarily because of the use of HVDC technology.

Brattle said there could be additional savings of 20 to 30% from increased competition under the planned strategy.

The study, buttressed with engineering, cost and seabed analyses by *Pterra*, *PSC Consulting* and *Intertek*, was presented and discussed in a webinar Thursday. The New York *League* of Conservation Voters Education Fund, Anbaric and the *Sabin Center* for Climate Change Law at Columbia University hosted the virtual event, which Consolidated Edison sponsored.

Following is some of what we heard at the event.

Clockwise from top left: Joe Martens, NYOWA; Kevin Knobloch, Anbaric; Girish Behal, NYPA; and Kirsty Townsend, Ørsted. | *Sabin Center*

GLL Approach

Project	Size (MW)	Upgrades	Estimated Cost (Mil 2020$ USD)
Fresh Kills	800	345 kV cable circuit	$185
Gowanus	800	Two 138 kV and 345 kV cable circuits	$467
Ruland Rd	1200	New 345 kV substation and upgrade line to 345 kV	$78
Brookhaven	1200	Four 138 kV circuits	$497
Barrett	1184	Eight 138 kV circuits	$777

Total: $2,000 Million

Planned Approach

Project	Size (MW)	Upgrades	Estimated Cost (Mil 2020$ USD)
Fresh Kills	1700	Two 345 kV cable circuits	$223
Rainey	1200	Two 138 kV cable circuits	$117
Ruland Rd	1200	New 345 kV substation and upgrade line to 345 kV	$78
East Garden City	1100	138 kV circuit	$97

Total: $515 Million

Brattle found a planned approach in New York could save $1.5 billion in onshore upgrades compared to a GLL approach. | *The Brattle Group*

Hurry Up and Wait

Joe Martens, director of the New York Offshore Wind Alliance and former commissioner of the state's Department of Environmental Conservation, referred to the Accelerated Renewables Growth and Community Benefit Act enacted in April as part of a budget *bill* that aimed to speed up the state's clean energy transition.

"In addition to completely rewriting the way renewable energy is sited in New York, and establishing very strict timetables, [the act] was an acknowledgement that we were really good at entering into contracts, but not so good siting and getting projects built," Martens said. "We're at about a 27% renewable penetration in the electricity sector today in New York, and 20% of that is legacy hydro projects upstate, so we have a long way to go."

The siting law also called for a study by year-end of the transmission system, both onshore and offshore, he said.

The Public Service Commission in May approved such a study to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals of 70% renewable electricity by 2030 (*20-E-0197*). (See *NYPSC Launches Grid Study, Extends Solar Funding*.)

NYISO News

The PSC and the New York State Energy Research and Development Authority also issued a *white paper* in June, and one question in it regarded the second OSW solicitation for up to 2,500 MW, Martens said.

"One of the big questions was how to approach transmission in this second solicitation," Martens said. "In the first solicitation, it was decided that a so-called radial system, where the developer designs and builds the transmission just to accommodate their project, was the right approach because we don't have any commercial-scale offshore wind projects to date, and we wanted to get the program up and running as quickly as possible."

However, even during the phase one solicitation, people raised the question about looking at a network system, as the state anticipates "multiple projects being built, not just off New York, but across our sister states to the north and south," he said.

The white paper proposed that for the second solicitation, developers build radial transmission lines because "the potential for a backbone network remains speculative, primarily because there is still a lot of uncertainty about where new wind energy areas would be located and how soon they would be leased in the New York Bight," Martens said. "However, the white paper acknowledged that this is still a very important issue and needed to continue to be studied."

The PSC's grid study includes investment plans for both the bulk and local transmission systems. "And of course, a key component of that study is the offshore wind transmission analysis, and part of that analysis is consideration of offshore network configurations," said Tammy Mitchell, chief of bulk electric systems for the state's Department of Public Service. "The final results of that study are due at the end of the year, and preliminary results will be available in the fall."

Many projects are moving through the Article VII transmission siting process, and the DPS should soon be proposing rules for a nine-month process, Mitchell said.

Rules and Need

States along the East Coast cooperating on the issue would bring more opportunities for bringing OSW energy ashore where it makes

Joe Martens, NYOWA | *Sabin Center*

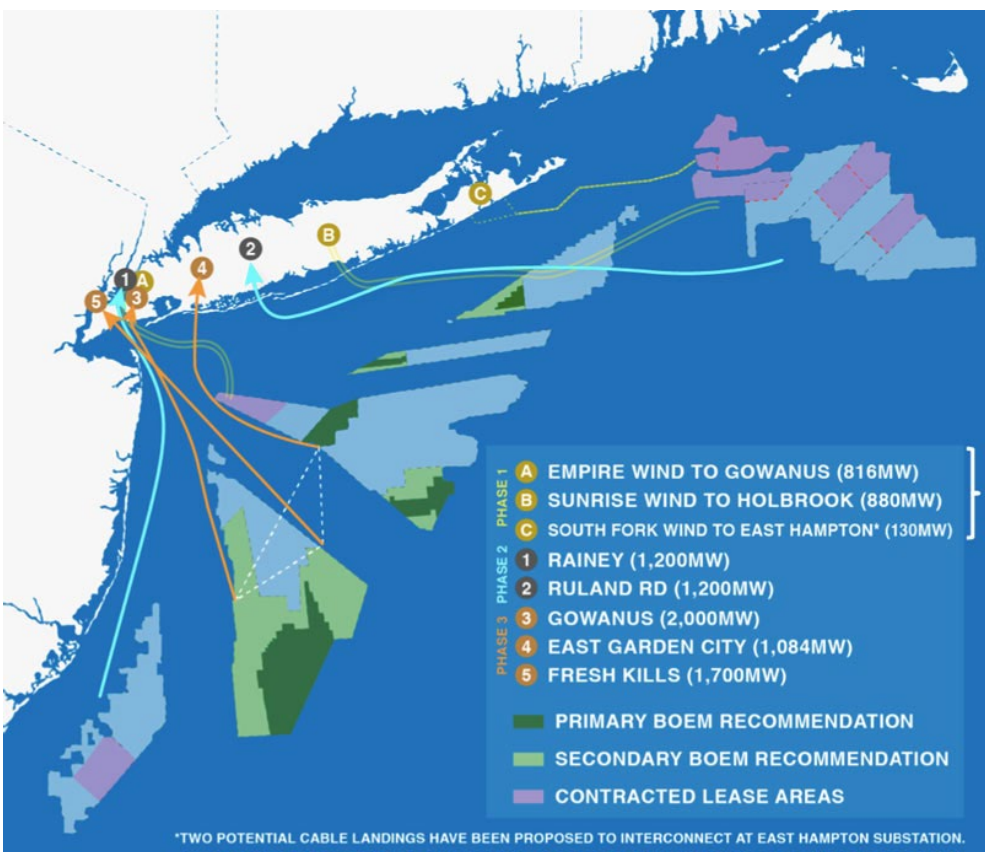
sense, perhaps at shorter distances, said Kevin Knobloch, president of Anbaric subsidiary New York OceanGrid.

"Ultimately, what we're looking for is an open-access transmission system, where there's maximum competition among not just generators, but transmission developers, which can also be generators," Knobloch said. "Robust competition is what will ultimately bring costs down and get this power to shore."

New York has the greatest need for shared transmission and is in the lead to deal with it, said Kirsty Townsend, head of special projects at Ørsted.

"The *IEEE standards* for offshore don't exist in the U.S., so it would be great to establish that so we can actually connect multiple wind farms into these shared infrastructures," Townsend said. "I think some of the ISO's market rules could [use] improving, or finding another way round in order to achieve the public policy goals. It's something we as developers, both transmission and generation, are already struggling with, and I can see this kind of shared transmission system only exacerbating those issues, interconnection queue process rules, for example."

Massachusetts also is interested in exploring the benefits of multistate cooperation on offshore transmission. Patrick Woodcock, commissioner of the state Department of Energy Resources, said last month that a network transmission "initiative could be achieved more effectively at a larger scale of offshore wind build-out and with regional coordination among New England states … than through a single-state procurement with limited size." (See *Mass. Nixes Separate Offshore Tx RFP*.) ■



Brattle's study shows likely offshore transmission buildout under a planned approach. Phase 1 is already contracted using HVAC cables. Planned approach would use HVDC cables for Phases 2 and 3. | *The Brattle Group*

NYISO News

NYISO's 2nd Storage Compliance Almost Hits Mark

By Michael Kuser


NYISO wants to exempt resources like NYPA's 1,134 MW Blenheim–Gilboa Hydroelectric Power Station in the Catskill Mountains from Order 841 transmission charges.

FERC last week accepted most provisions in NYISO's second attempt to comply with Order 841, which requires RTOs and ISOs to remove market barriers for energy storage resources (ESRs).

The decision specifically accepted proposed Tariff revisions to subject ESRs to transmission charges, effective no later than Sept. 30, but ordered the ISO within 90 days to clarify its proposed exemptions to such charges (*ER19-467*). The commission faulted the initial compliance filing for failing to apply those charges to ESRs when they are charging in the wholesale market for later retail sale but not providing services to the grid.

The commission also deemed NYISO's Jan. 21 *request* for rehearing to be denied by operation of law.

Issued in 2018, Order 841 requires market participation rules to recognize the unique physical and operational characteristics of storage resources. The commission last December partially accepted NYISO's compliance filing but faulted the ISO for lack of details on its metering methodology and accounting practices for ESRs located behind a customer meter. (See *FERC Partially Accepts NYISO Storage Compliance*.)

In its second compliance *filing* in February, the ISO proposed not to assess transmission charges to ESRs when the resource receives a real-time operating reserves schedule; receives a real-time regulation service schedule; is operating and is a qualified supplier of voltage support service; or is dispatched as out-of-merit to meet New York Control Area (NYCA) or local system reliability.

FERC accepted those provisions, but required NYISO to provide clarifications, saying that because these services are typically scheduled on top of a resource's base energy schedule, it is unclear what portion of a resource's megawatt withdrawals the ISO proposes to exempt from transmission charges, in particular of withdrawals during an interval when the resource is self-scheduled at a fixed megawatt quantity.

Pumped up

In its request for rehearing, NYISO argued that its proposed approach to not assess transmission charges aligns with its existing rate structure for transmission charges assessed to resources in the NYCA that withdraw energy at a node for later injection into the grid.

Specifically, NYISO said for more than 20 years it has applied a separate rate structure for transmission charges applicable to the 1,134-MW Blenheim-Gilboa Hydroelectric Power Station in the Catskills, a pumped storage facility owned by the New York Power Authority. The ISO argued that the station is located at a single generator bus that pays the nodal locational based marginal price (LBMP) to withdraw energy as a "negative injection" for later injection back into the grid.

NYISO sought to apply the same separate rate structure to all nodal ESRs in in its jurisdiction and said that under Order 841, when such resources are marginal in the ISO's dispatch of energy, loads in the NYCA would effectively be paying the related charges twice — once as part of the energy component of LBMP and again when NYISO and the relevant New York transmission owner assess charges to the loads.

But the commission said it was not persuaded by NYISO's request for rehearing and continued to find the ISO has not demonstrated, as required in Order 841-A, that its proposal not to apply transmission charges to all ESRs is reasonable given how it assesses transmission charges to wholesale load under its existing rate structure.

"As a general matter, NYISO assesses transmission charges to all wholesale load, and it only declines to assess transmission charges to the withdrawals by one specific pumped storage facility when that facility is participating under the energy limited resource (ELR) model," the commission said. "Thus, NYISO's proposal not to apply transmission charges to any energy storage resource is not consistent with or reasonable given its existing rate structure, as contemplated by Order No. 841-A."

The commission also said that NYISO's double payment argument "is, in essence, a late-filed request for rehearing of Order No. 841 and is statutorily barred. Notwithstanding this procedural flaw, NYISO's argument is also unpersuasive on the merits."

Two different transactions occur, the commission said: "One that entails the electric storage resource purchasing charging energy at wholesale from the RTO/ISO market, and another that entails wholesale load purchasing energy from the electric storage resource via the RTO/ISO energy market. As such, we find that it is reasonable to apply transmission charges to both the electric storage resource and the loads associated with those separate transactions and for load to ultimately pay the two transmission charges."

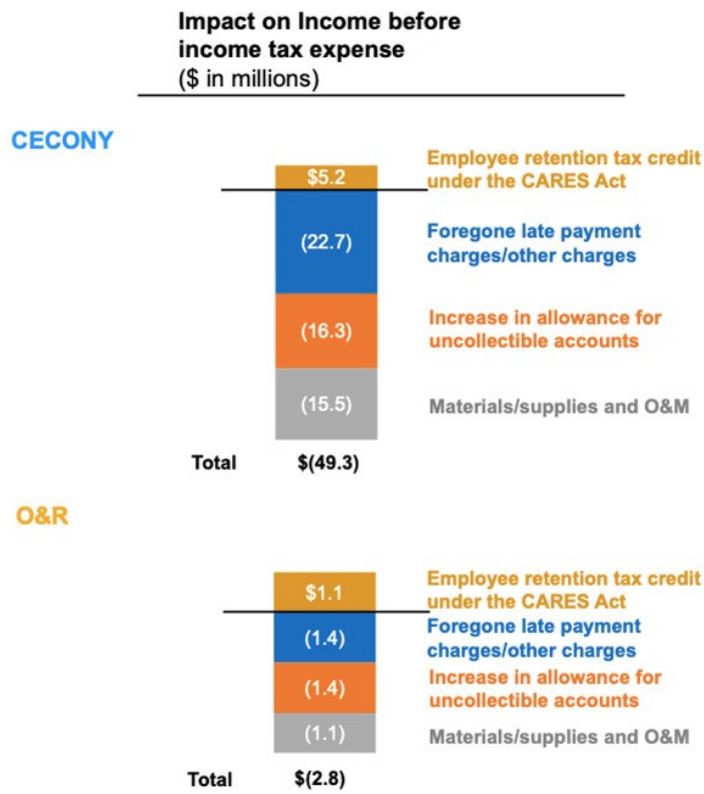
NYISO also argued that FERC's rejection of its proposal was inconsistent with the commission's acceptance of a CAISO proposal to exempt all ESRs from transmission charges when charging, consistent with CAISO's existing rate structure.

Not so, said the commission.

"Unlike CAISO's non-generator resource model, which was designed for electric storage resources, NYISO's ELR model is designed for and primarily used by generators. Indeed, NYISO withdrew its ELR model from consideration for compliance with Order No. 841 because, according to NYISO, the ELR model could not accommodate withdrawals from ESRs."

NYISO's treatment of one pumped storage facility under the ELR model is thus a limited exception and not representative of how the ISO assesses transmission charges to wholesale load under its existing rate structure, the commission said. ■

Con Ed Takes $52 Million Hit from COVID



Con Edison reported the pandemic had a negative impact on net revenues of $52 million in the first half of 2020. | *Con Edison*

Consolidated Edison said Thursday that the COVID-19 pandemic had negatively impacted its first-half earnings by $52 million — a report that came as the utility struggled to restore power to its more than 500,000 customers in and around New York City after Tropical Storm Isaias hit two days earlier.

The negative impact primarily reflects foregone revenues from the suspension of customer late payment charges and certain other fees associated with the pandemic, as well as higher depreciation and amortization expense, offset in part by the Employee Retention Tax Credit under the CARES Act, the company said.

Despite the effects of the pandemic, net income for the first six months of 2020 was $565 million ($1.69/share), only a 2% drop from the $576 million ($1.77/share) in the first half of last year. Con Ed also reported second-quarter net income of $190 million ($0.57/share), compared to $152 million ($0.46/share) during the same period in 2019.

"We are facing today's unprecedented challenges by providing essential and reliable service during the pandemic," CEO John McAvoy said in a *statement*. "We understand the hardship that Tropical Storm Isaias has had on our customers, and we are working around the clock to restore service."

McAvoy said crews were restoring power to approximately 300,000 Consolidated Edison Company of New York (CECONY) and 225,000 Orange & Rockland Utilities (O&R) electric customers affected and called Isaias "the second-worst storm in our company's history."

The company highlighted the New York Public Service Commission's decision in July to establish a light-duty electric vehicle "make-ready" program, which includes budgets of $290 million and $24 million for CECONY and O&R, respectively, through 2025, for fast-charger stations and other services. (See *NYPSC Approves $700 Million for EV Chargers*.) ■

— Michael Kuser

Con Edison's long-range plan forecasts EV-related usage will reach 7.2% of system peak, or 107 MW, in 2038. | *Con Edison*

Overheard at NY-BEST's 10th Annual Meeting

Tropical Storm Isaias battered New York City and Long Island on the first day of the three-day, 10th annual conference held last week by the New York Battery and Energy Storage Technology Consortium (NY-BEST).

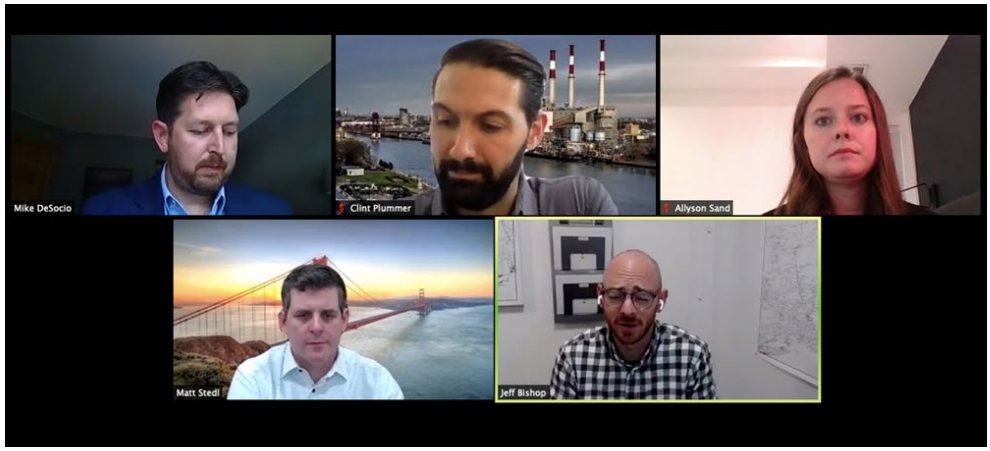
The storm on Aug. 4 left nearly 1 million island and city residents without power and prevented Mike Voltz of PSEG Long Island from participating as scheduled in a utility storage panel, while technical problems with the virtual platform made New York Public Service Commission Chair John B. Rhodes the *de facto* opening speaker.

None of those problems, however, seemed to stop the more than 400 conference participants, nor the panelists dedicated to energy storage in all its permutations.

NYISO and all power-related state agencies are working to achieve the goals set out by last July's landmark Climate Leadership and Community Protection Act (CLCPA), which include getting 70% of the state's electricity from renewables and deploying 3 GW of energy storage by 2030.

"Everything is combining all at once now, so it's impossible not to be bullish on New York whenever it comes to batteries," said Jeff Bishop, CEO of Key Capture Energy.

Following is some of what we overheard at the event.



Clockwise from top left: Mike DeSocio, NYISO; Clint Plummer, Ravenswood; Allyson Sand, Plus Power; Jeff Bishop, Key Capture Energy; and Matt Stedl, Savion | *NY-BEST*

Setting the Table

Rhodes said the PSC's most important action on storage so far has been issuing its December 2018 order to "set the table" for the deployment of storage, with milestones now of 1.5 GW by 2025 and 3 GW by 2030 (*18-E-0130*).

"Our investor-owned utilities will continue to procure at least 350 MW of bulk storage dispatch rights," Rhodes said. "And we are examining — as many of you have urged us to — storage demand charges within the revised standby rates based on a cost allocation approach that is more granular, but importantly, more accurate."

He said the PSC is reviewing the IOUs' proposals for three-year dynamic load management, starting in 2021. In storage, dynamic load management means optimizing load so that power is evenly distributed to all resources that are charging simultaneously, including electric vehicles, and that the batteries charge to full volume when capacity is sufficient.

"In terms of resource adequacy, our staff and the New York State Energy Research and Development Authority continue to advocate for changes to NYISO's buyer-side mitigation [BSM] rules," Rhodes said. "That's a set of actions that will come ahead of our resource adequacy proceeding."

FERC in May partly accepted NYISO's March compliance filing on BSM rules, ordering the ISO to submit an additional filing on the rules for special-case resources, a type of demand response resource (*EL16-92-002, ER17-996*). (See *FERC Partly OKs NYISO Mitigation Language*.)

To demonstrate the rapid growth of storage resources in New York, Rhodes shared a graph showing how storage interconnection queues grew from 887 MW to 1,264 MW in the first half of the year.

David Lovelady, a principal engineer at National Grid, spoke of co-optimizing storage projects through value stacking to maximize total benefits, in particular with a *solicitation* last year for four storage projects upstate and in the capital region, each to be a minimum 10 MW.

"Perhaps during spring load periods when the load is lighter ... we can participate more in the ISO market, and when it comes to the summer period when we have peak load, then we might need to hold some state of charge back for a reliability event," Lovelady said. "We're working closely with NYISO on these projects."

Global Politics and Safety

Professor M. Stanley Whittingham of Binghamton University, winner of the 2019 Nobel Prize in chemistry for his work with lithium-ion batteries, gave the conference a unique perspective on the storage industry.

A NY-BEST founding director and still the organization's research chair, Whittingham in January was named by Gov. Andrew Cuomo to lead a task force to provide the state with an aggressive roadmap to the EV future.

"The lithium-ion battery will help mitigate what I call the messing up of the world," Whittingham said.

"We need to further build a New York state ecosystem for energy storage," he said. "We've got great universities; we've got Brookhaven National *Lab*, with all its capabilities; we've got New York BEST [and] the very supportive state government; but what we really need to do is develop new manufacturing technologies."

Whittingham said that the U.S. and Canada need to use research and development to leapfrog the existing 30-year-old technologies used in Asia.

"We need to be to some extent self-contained," he said. "All the anode materials, the graphite, comes through China, and essentially all the cobalt comes through China, so that is creating issues and will create issues in the future."

The industry also should strive to eliminate toxic chemicals from the manufacturing process and, in time, to make the cells in a way that enables deconstruction and makes recycling easier, Whittingham said.

"Another way we could have a large saving in capital expense is to provide for an effective solid electrolyte interphase formation. This is the layer formed on the graphite anode. It takes from one week to three weeks of break-

NYISO News

in on the manufacturing site. If we could do that during the actual manufacturing of the cells, we'd save a lot of money for everybody," he said.

One area that has been somewhat neglected, Whittingham said, is to provide for more effective heat management and safety.

"We've seen the *issues* with Samsung, and there were safety issues we saw in the Boeing 787, where really those batteries had not been designed for effective heat management or for safety," he said. "Right now, a group of us are working to propose building a new factory, a pilot battery facility with manufacturing capability within the state. ... We believe there are opportunities to build U.S. manufacturing and the supply chain within the U.S. and Canada, which has lots of nickel and quite a lot of lithium."

Exciting Times

The year 2020 would have been an unusually impactful one for the state's grid operator even without the adjustments necessitated by the COVID-19 pandemic, NYISO CEO Rich Dewey said.

"When you look at what's going on in the utility industry — the electric space — it probably is the most exciting time, certainly in my career, and maybe in the history of the industry," Dewey said.

The CLCPA has amped up the approach and the process to transitioning to a clean energy power sector and economy, but NYISO is first and foremost responsible for reliability, markets and planning, he said.

In planning for the changes underway, the ISO is not taking "a deterministic approach but really looking at what are the guiderails, what are the options, and that will allow developers, policymakers and system planners the ability to see what different mixes of different resource types will look like, and ultimately what they'll cost, and what is the most efficient resource mix," Dewey said.

The ISO's planning team knows that the interconnection queue has been a barrier to timely and rapid entry for new technologies, he said.

"Storage technologies can probably be deployed faster than any of the other renewable or innovative types of resources, so we knew we had to revamp the interconnection class year, and I'm happy to say we're getting very close to finishing up the first class year under these new rules," Dewey said. "The previous class year had 26 projects, and it took us 26 months. ... This year's class year started with about 91 projects, and I think we're going to be on target to [complete the reviews in] about 13 months, maybe 14 months."

Dewey also highlighted the ISO's progress on formulating market rules for storage, noting that earlier in the week, FERC gave final confirmation on most of the rules. (See related story, *NYISO's 2nd Storage Compliance Almost Hits Mark*.)

Because hybrid resources such as solar paired with storage are increasingly popular with developers, NYISO last month decided to accelerate its hybrid modeling capability, both within its markets and within its system. The ISO hopes to complete the market enhancement next year, he said.

"More broadly, properly sited and properly configured and performing storage provides tremendous flexibility to different transmission scenarios," Dewey said. "Whether it's a two-hour asset or a four-hour asset, whether it's in New York City close to the load or located upstate near a critical transmission constraint, we want to be able to start exposing some of those variations to our planning studies, so then developers can make investment decisions that most benefit the system and give them the highest return."

In the Market

LS Power subsidiary Ravenswood Power, the largest power plant in New York City, representing more than 20% of installed capacity in Zone J, last year won regulatory approval to build a 316-MW battery storage facility on its site in Queens. (See "Largest Storage Project in New York," *NYPSC Projects Lower Winter Energy Prices*.)

"We've seen with the advent of policies over time, like Local Law 97 [capping greenhouse gas emissions for buildings] and CLCPA, there will be a need for replacement capacity to be developed to serve the needs that our facilities currently serve, so we want to be on the forefront of developing that capacity," Ravenswood CEO Clint Plummer said.

For a big increase of capacity from intermittent renewable resources to work on a system level, "we're going to need large-scale bulk and distributed energy storage in quantities that have not been seen on systems anywhere else in the world, and New York remains out in front in terms of a policy perspective of thinking through what that means," Plummer said.

Allyson Sand is a project developer at Plus Power, a battery energy storage company focused on utility-scale storage using a data-driven approach, with a portfolio of 2,000 MW in projects around the country.

In New York, Plus Power is developing several projects, with a focus on zones A, K and G, Sand said.

"At the state level, we see a lot of positive activity happening, with significant investment from the utilities and from NYISO to incorporate storage," Sand said. "It's clear to us that the state is really committed to achieving their goal and making storage possible on a larger scale." ■

— Michael Kuser

Clockwise from top left: Eva Gardow, EPRI; Damian Sciano, Con Edison; and David Lovelady, National Grid | *NY-BEST*

PJM News

Exelon's Nuclear Units Face Uncertain Future

CEO Apologizes for Bribery Scandal During Earnings Call

By Tom Kleckner

Exelon CEO Chris Crane last week apologized for subsidiary Commonwealth Edison's involvement in a bribery scandal and said he may be forced to shut down the company's Illinois nuclear plants without favorable state legislation.

In July, ComEd agreed to a $200 million fine with the Illinois U.S attorney's office to settle allegations it bribed the state House of Representatives' speaker in return for legislation that increased the company's earnings and bailed out its money-losing nuclear plants. Under the *Deferred Prosecution Agreement*, the bribery charge will be deferred for three years and then dismissed, as long as ComEd continues to cooperate with "ongoing investigations of individuals or other entities." (See *ComEd to Pay $200 Million in Bribery Scheme*.)

"We've taken robust actions to identify and address deficiencies, including enhancing our compliance governance, to prevent this conduct," Crane said during a conference call with financial analysts. "We apologize for the past conduct, which did not live up to our values. These new policies will ensure it won't happen again.

"We're extremely disappointed with the seriousness of the past misconduct," he said, listlessly reading his prepared comments. "We know many stakeholders understandably feel the same disappointment. We will take every possible step to earn back the confidence and trust we have lost. This will not happen overnight, and it will be a formidable task, but we're resolved to get there."

Exelon CEO Chris Crane | © *RTO Insider*

Exelon building at Baltimore's Harbor Point | *BHC Architects*

Crane said Chicago-based Exelon must restore the trust that "has been eroded" while, at the same time, working through legislative strategy in Illinois to help its nuclear plants earn capacity market revenue.

"It's very critical for us to get it done," he said, noting his "analytic folks" have a "strong sense" that Exelon's nuclear units will not clear the next PJM Base Residual Auction.

"Some are uneconomic at this point right now, and some may become more uneconomic," Crane said. "If we can't find a path to profitability, we're going to have to shut them down. We will not run plants and lose free cash flow or earnings on assets that are not supporting themselves. … We will not let the balance sheet [be] further [deteriorated] by non-profitable assets."

Exelon has lost 14.7% of its stock value since the year began.

The company *reported* a "strong quarter" with earnings of $521 million ($0.53/share). A year ago, the company had earnings of $484 million ($0.50/share).

Exelon's operating earnings of $0.55/share beat analysts' expectations of $0.42/share, as gathered by Zacks Investment Research. The stock price gained 76 cents on the NASDAQ, closing at $38.75. ■

PJM News

Akins: AEP's Actions 'Lawful, Ethical'

Defends Company's Linkage to Ohio HB6 Scandal

Continued from page 1

Akins said the company has contributed $8.7 million since 2015 to Empowering Ohio's Economy, a 501(c)(4) nonprofit organized to promote economic and business development in Ohio. The contributions, he said, were "appropriate and lawful," and he noted that AEP has contributed to a variety of such organizations.

"We consistently advocate for policy positions that benefit our customers, communities and shareholders, and our advocacy of HB6 was no different," he said. "We ultimately supported the legislation because we believe it maintained important fuel diversity for Ohio, including support for investments in renewables, nuclear generation and two [Ohio Valley Electric Corp.] coal plants."

AEP owns 43% of OVEC.

Given "concerns that some have expressed regarding the lack of transparency surrounding 501(c)(4) organizations," Akins said, AEP will commit to include[ing] additional disclosures about its contributions to the organizations in its 2020 corporate accountability report and going forward. Those nonprofits are not required to disclose their donors and the amount of donations.

"We also are reviewing best practices and working to improve our policies and processes around political contributions and contributions to 501(c)(4) entities," he said.

The Columbus Dispatch, AEP's hometown newspaper, reported in July that the company

AEP's headquarters building in Columbus, Ohio

has contributed to Empowering Ohio's Economy, which is part of a federal case that has led to the indictment of Ohio House Speaker Larry Householder and four associates on criminal charges. The nonprofit gave $150,000 to Generation Now, a dark money group that received $61 million from FirstEnergy interests to ensure HB 6's passage, the Dispatch said. (See *FirstEnergy, AEP CEOs Deny Wrongdoing*.)

The legislation provided $1 billion in subsidies to a pair of coal plants in which AEP has a 43% stake and two nuclear plants. Businesses, legislators and ratepayers have all called for HB 6 to be repealed.

"We were surprised and disappointed to learn of what federal investigators allege was a scheme by the speaker of the Ohio House and others to enrich themselves, and we, along with you, have been trying to educate ourselves about the criminal complaint and the underlying conduct in it," Akins said.

The comments came the same day Householder and others were to be arraigned in federal court on racketeering and bribery charges. Householder's *hearing was delayed* after he requested new legal representation.

AEP *reported* quarterly earnings of $521 million ($1.05/share), an increase from 2019's second-quarter earnings of $461 million ($0.93/share).

The company's stock price rose 54 cents during the day, closing at $84.83. ■

PJM MIC Briefs

Manual 14D and 27 Revisions

PJM stakeholders unanimously endorsed deadline changes for adjustments associated with finalizing the zonal network service peak load (NSPL) values in Manual 14D and Manual 27.

Ray Fernandez, PJM manager for market settlements development, reviewed updates to the generator operational requirements in Manual 14D and the Open Access Transmission Tariff Accounting section of Manual 27. The Manual 27 revisions were endorsed at Wednesday's Market Implementation Committee meeting, while the related Manual 14D revisions were endorsed the following day at the Operating Committee meeting.

The revisions are related to the border yearly charge (BYC) — the charge for long- and short-term point-to-point transmission service for points of delivery at PJM's border, which goes into effect on Jan. 1 of each year.

Fernandez said deadline dates in both manuals conflicted with the deadline dates of the BYC, including ones for the NSPL verification and zonal adjustments.

In Manual 14D, the behind-the-meter generation business rules had a Dec. 1 deadline for a load-serving entity to request a downward adjustment to its NSPL or obligation peak load. PJM proposed revising the deadline from Dec. 1 to Oct. 31.

Changes in Manual 27 included adding clauses to section 5.2 stipulating adjustments that need to be provided to PJM Market Settlements by Nov. 10. Any adjustments provided after the deadline will not be included in the NSPLs for the next calendar year and won't be used in the BYC calculation.

The manual changes were originally up for endorsement at the July MIC meeting, but Fernandez said stakeholders raised objections with language contained in Manual 14D relating to BTM generation. Fernandez said PJM met with stakeholders to address the issue and were able to reach an agreement on compromise language.

ARR/FTR Market Task Force Poll

Members voted to put the ARR/FTR Market Task Force on hiatus until an independent consultant completes a review of PJM's auction revenue rights and financial transmission rights market constructs.

Dave Anders, PJM | © RTO Insider

Dave Anders, PJM director of stakeholder affairs, reviewed the results of the task force poll taken in July and discussed its recommendation to go on hiatus.

The nonbinding poll had 140 respondents, with 124 voting (89%) to put the group on hiatus until the consultant completes its work.

Anders said feedback from stakeholders resulted in an increase in the scope of the work to be completed by the consultant. (See PJM Revises Consultant Scope for ARR/FTR Review.) The hiring of a consultant was one of the recommendations in last year's independent report on the GreenHat Energy default. The review is anticipated to take 12 weeks. (See PJM Revises Consultant Scope for ARR/FTR Review.)

Anders said PJM is "in the final throes" of awarding the contract for the consultant and close to completing the final negotiation for the scope of work. He said stakeholders should expect an announcement "shortly" on the hiring.

Erik Heinle, D.C. OPC | © RTO Insider

Erik Heinle, of the D.C. Office of the People's Counsel, asked Anders if stakeholders will have an opportunity to meet with the consultant as they're working on the report or after it's completed. Anders said plans are being finalized, but he expects there will be some interaction between the consultant and stakeholders.

Market Suspension Settlements

PJM is exploring the development of business rules to address a market suspension from an emergency or some other incident.

Tim Horger of PJM provided a first read of a problem statement and issue charge to develop business rules. The RTO is looking for approval of the issue charge at the September MIC meeting.

Horger said PJM has been contemplating scenarios of a market suspension with no day-ahead or real-time LMP results and realized that it had limited guidance on how to handle settlements during a suspension.

Tim Horger, PJM | © RTO Insider

PJM has never experienced a market suspension event and doesn't anticipate that it would occur, Horger said, but the RTO feels it needs to create business rules to apply to all possible scenarios.

The key work activities and scope for the issue include:

reviewing instances for which a market suspension may occur;

- reviewing consequences to the market associated with a suspension;
- reviewing PJM's existing business rules, along with procedures of other RTOs/ISOs in the event of a suspension; and
- reviewing options for how settlements can be determined in the event of a suspension.

Horger said work on the issue is estimated to take about three months and could start as early as October if the issue charge is approved next month.

Sharon Midgley, Exelon | © RTO Insider

Sharon Midgley of Exelon asked if the problem statement and issue charge only relate to the energy market or if it could also apply to all of PJM's markets.

Horger said the "obvious" market seemed to be energy, but it could apply to all markets and would be determined in the key work activities.

Midgley said she thought the duration of the work needs to be considered because of the complexity of the issue. "I don't think it's going to get done in three months unless there's already a solution in mind," she said. ■

— Michael Yoder

PJM News

PJM PC/TEAC Briefs

Planning Committee

Load Model Endorsed

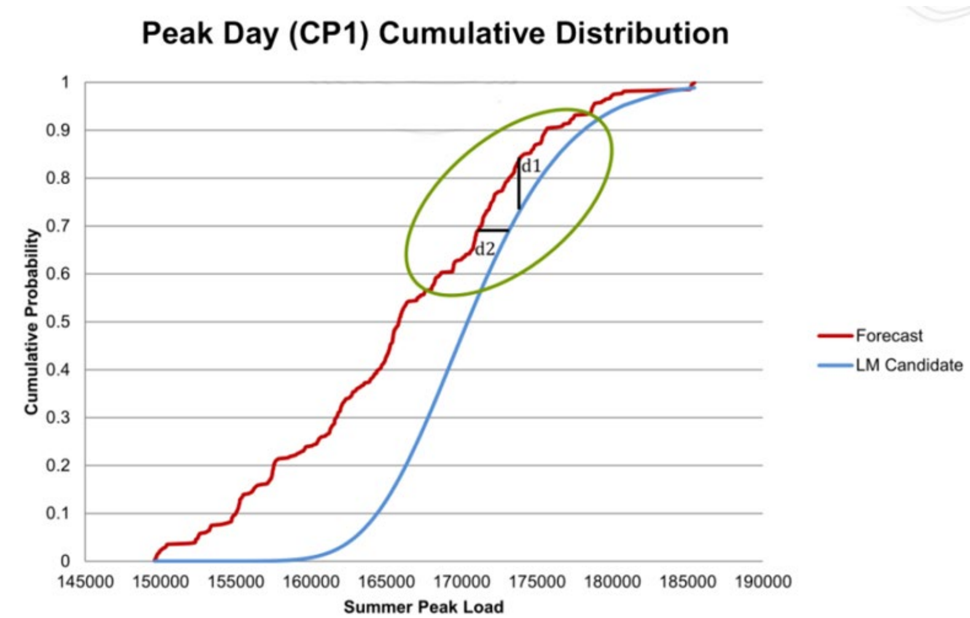
The PJM Planning Committee unanimously endorsed the RTO's recommendation to use a 13-year load model with data from 2002 to 2014 for the 2020 reserve requirement study (RRS), a change from the 10-year model (2003-2012) that has been used for the last several years. The load model, which was first presented at last month's PC meeting, was passed by acclamation vote with no objections and one abstention. (See "Load Model Selection," *PJM PC/TEAC Briefs: July 7, 2020*.)

Patricio Rocha Garrido of PJM's resource adequacy department *presented* the committee with the results of the RTO's load model selection process, which analyzed 105 load model candidates for the 2020 RRS for the 2024/25 delivery year. Rocha Garrido said the analysis was based on the *2020 PJM Load Forecast Report* released in January.

The load model candidates were compared to PJM's "coincident peak 1" (CP1) distribution analysis, Rocha Garrido said, which represents the highest load expected for the forecast year, using two separate approaches. The previously selected load model was not one of the top candidates this year, Rocha Garrido said, because of a new CP1 distribution analysis.

Rocha Garrido said the load model selection has to be done because the coincident peak distributions from the PJM load forecast cannot be used directly in the PRISM modeling software.

"We need to find a load model that is a good match for the PJM load forecast that we can then input into PRISM," Rocha Garrido said.



Load model candidate vs coincident peak 1 from load forecast. Stakeholders unanimously endorsed PJM's recommendation to use a 13-year load model with data from 2002 to 2014 for the 2020 reserve requirement study. | *PJM*

Endorsement of Manual 14 Changes

Stakeholders also unanimously endorsed changes to Manual 14, including new sections detailing the requirements for surplus interconnection requests, a new definition of permissible technological advancements and a section outlining the evaluation procedure for surplus interconnection requests.

FERC required PJM to add language on how the RTO handles surplus interconnection service and incorporation of technological advancements in its interconnection process in its second Order 845 compliance filing. (See *FERC OKs Most of PJM Order 845 Compliance Filing*.)

Onyinye Caven of PJM *presented* the changes to Manuals *14A*, *14B* and *14G*, which incorporate Tariff changes from the Order 845 compliance filing. Caven said there were "no substantive changes" from the first read that was conducted at the July PC meeting.

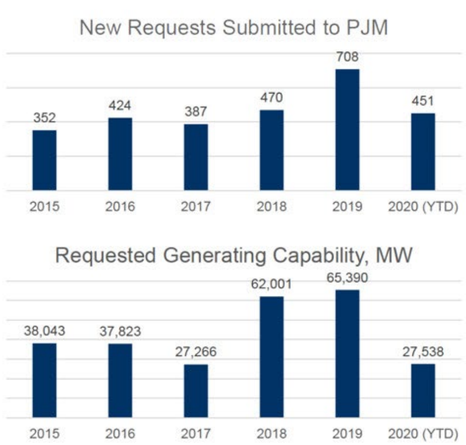
Caven said the changes related to the incorporation of technological advancements in the FERC order took effect on July 20, while the changes for surplus interconnection service will take effect in November.

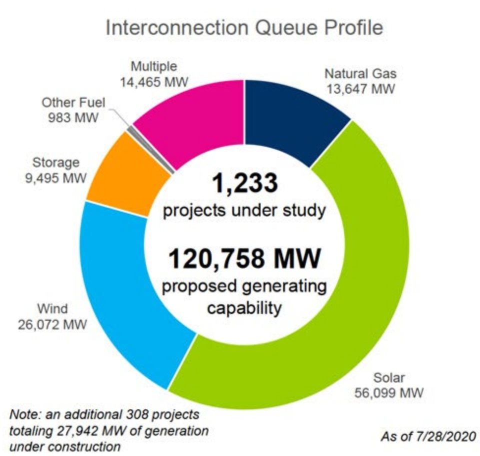
Stakeholders will vote on final endorsement of the changes at the Markets and Reliability Committee meeting Aug. 20.

Interconnection Study Statistics

Susan McGill, manager of interconnection analysis for PJM, *presented* the interconnection study statistics for the first half of 2020, a new requirement for the RTO under FERC Order 845. McGill said one of the changes out of Order 845 was the collection of common interconnection metrics across the country.

McGill said PJM requested that FERC allow





| *PJM*

PJM News

the RTO to calculate for a six-month period to align with its six-month queues instead of the quarterly reports used more commonly.

FERC established a performance rate standard of 25% or below for report delays, McGill said. Entities having two consecutive reporting periods greater than a 25% performance rate are required to issue a detailed filing to the commission explaining the delays and describing mitigation efforts.

The rate is calculated as the sum of the studies issued late and those backlogged, divided by the sum of backlogged studies and total studies issued.

McGill said PJM issued 321 feasibility studies in the first half of 2020. Of those, three were late and one was backlogged or "currently delayed." The average completion time was 88 days, and the performance rate was 1.2%.

A total of 305 system impact studies were issued at the same time, McGill said, with 35 late and 53 backlogged. The average completion time was 187 days, and the performance rate was 24.6%.

Of 25 facilities studies issued in the first half of the year, all but one was late and 145 are currently backlogged. The average completion time is 747 days, and the performance rate is 99.4%.

McGill said PJM is working to fix the facilities studies delays. She said the RTO is adding contract support to perform studies and project facilitation, including eight new contract engineers by the end of the summer to work on interconnection reports and analysis.

"We're going to talk internally to see what type of plans we have to address the facilities studies," McGill said.

She said the total number of studies is increasing "drastically" in PJM. In 2018, 583 studies were due, compared to 1,434 studies due in this year.

The backlog of studies is decreasing at the same time, McGill said. After peaking in March 2019 at 353 studies, or about 28% of projects, the backlog has dropped to 207 studies, or 17% of projects.

"We're making a lot of headway even though there's still work for us to do," McGill said.

COVID-19 Load Impacts

Weekday load peaks remain below normal because of the COVID-19 pandemic lockdowns, although not as dramatically as in previous months, PJM's Andrew Gledhill told the PC in a presentation.

Gledhill said the weekday load peaks have come in 6.8% less, or approximately 6,600 MW, than what would normally be anticipated since states started instituting lockdown measures around March 23. Gledhill said the peak reductions are slightly lower than what was announced at the July PC meeting, when the load peaks dropped 8.2% (about 7,700 MW).

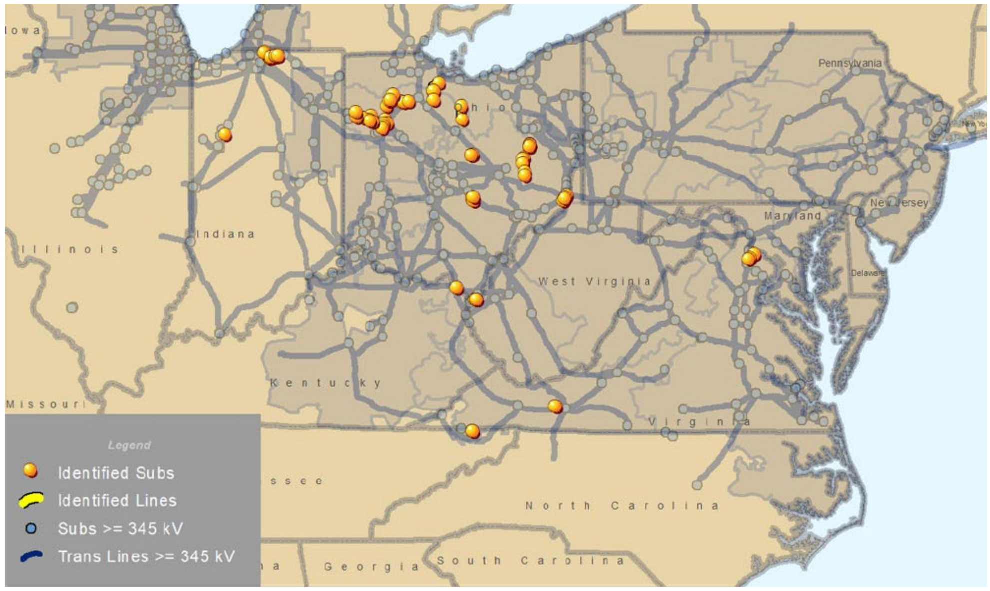
The peak load impacts have softened because of several factors, Gledhill said, including the continued easing of stay-at-home restrictions among PJM states and the opening of businesses.

Gledhill also said ongoing social distancing efforts have pushed more load to the residential sector than normal. He said residential loads have a greater sensitivity to weather conditions.

The PJM zones that have seen the smallest load impacts tend to be those with proportionately more residential load.

The average energy reduction has been 7.1% since March 23, Gledhill said, compared to 8% announced at the July PC meeting. The impact on total electric consumption has continued to exceed the impact on the peak.

Gledhill emphasized that the COVID-19 impacts are estimates and not definitive data. "There's no way to observe the actual impact of COVID-19, so we create estimates to understand the path of the pandemic and its impact on the grid," he said.



2020 RTEP reliability violations. The 2020 RTEP window for solutions to the violations under PJM, NERC, SERC Reliability, ReliabilityFirst and local TO criteria opened July 1 and is scheduled to remain open until Aug. 31. | *© RTO Insider*

Transmission Expansion Advisory Committee

Reliability Analysis Update

Aaron Berner of PJM provided an update on the 2020 Regional Transmission Expansion Plan (RTEP) analysis. The 2020 RTEP window for solutions to reliability violations under PJM, NERC, SERC Reliability, ReliabilityFirst and local transmission owner criteria that opened July 1 is scheduled to remain open until Aug. 31.

As of Aug. 4, 207 eligible flowgates had been posted in the window. About 290 eligible flowgates were originally posted, Berner said, but some were removed because of no-cost solutions that were found during the review process.

PJM also opened a second RTEP window for an end-of-life issue on the 500-kV Doubs-Goose Creek transmission line in the Dominion transmission zone. The 30-day RTEP window closed on July 31, Berner said, and PJM received one proposal for the project.

The project, which was originally presented at the June TEAC meeting, involved replacing steel lattice structures along the approximately 18-mile-long line. A third-party assessment determined that the towers have corroded to a point of instability and could result in failure and a collapse of the line if left unaddressed. ■

— Michael Yoder

ComEd, Madigan Sued for $450M in Racketeering Suit

By Michael Yoder

Illinois electric customers filed a federal class action civil racketeering *lawsuit* Monday against Commonwealth Edison and state House Speaker Michael Madigan (D), seeking more than $450 million in damages and an order barring the longtime politician from participating in any electricity legislation related to ComEd or parent Exelon.

Plaintiffs' attorney Stuart Chanen said ComEd's agreement to pay a $200 million fine to settle criminal allegations does not prohibit customers from pursuing additional damages under the Racketeer Influenced and Corrupt Organizations Act (RICO). (See *ComEd to Pay $200 Million in Bribery Scheme*.)

Chanen also said that although Madigan was not identified by name in the ComEd case, it does not limit plaintiffs from seeking injunctive relief against the politician.

ComEd's *deferred prosecution agreement* referred to Madigan as "Public Official A," saying the utility paid the speaker of the House of Representatives bribes in return for legislation that increased the company's earnings and bailed out its money-losing nuclear plants. (See *How ComEd Got its Way with Ill. Legislature*.)

"We filed our civil RICO case now to protect Illinois ratepayers from further damage by Michael Madigan — in both his capacity as speaker and as chair of the Democratic Party of Illinois — and also to get our clients back the damages they have suffered from ComEd's and Madigan's bribery scheme," Chanen said.

The civil lawsuit alleges one count of racketeering under RICO's civil provisions and one count of RICO conspiracy. It seeks several measures of relief, including:

- payment by the defendants of at least $450 million in damages to ComEd consumers, including $150 million in "ill-gotten gains" the utility admitted to in its deferred prosecution agreement and an additional $300 million under RICO's treble damages provision;
- an injunction preventing Madigan from participating in legislative activities involving electricity matters affecting ComEd and Exelon;
- an injunction preventing Madigan from continuing to serve as chair the Democratic Party of Illinois and "running it as a corrupt organization"; and
- an injunction barring ComEd from continuing to charge zero-emission credits for Exelon's Quad Cities and Clinton nuclear plants.

Illinois House Speaker Michael Madigan

The lawsuit also names other prominent defendants, including: Anne Pramaggiore, former ComEd CEO; John Hooker, former ComEd executive vice president; Fidel Marquez, former ComEd senior vice president; Jay Doherty, the longtime president of the City Club of Chicago; and Michael R. Zalewski, former Chicago alderman.

In crafting the complaint, lawyers for the plaintiffs said they relied heavily on ComEd's admissions in its the agreement with U.S. Attorney John Lausch. The complaint also emphasizes the $150 million in profits the Justice Department said ComEd earned in the alleged bribery scheme.

Attorney Patrick Giordano, another of the plaintiffs' lawyers, said that because ComEd admitted to the bribery scheme, and the RICO statute includes a treble damages award to "punish racketeers," company officials need to carefully weigh their options. "Pay back the $150 million to ratepayers now, or pay a joint and several $450 million judgment down the road," Giordano said.

Paul Neilan, who has litigated cases against ComEd for 20 years, is also part of the plaintiffs' legal team. Neilan filed a lawsuit in Cook County Circuit Court in 2013 challenging the 2011 Energy Infrastructure Modernization Act (EIMA), one of the bills that Madigan was allegedly bribed to support. The case was dismissed.

The deferred prosecution agreement said the EIMA allowed the utility to make billions in smart grid investments and switch to a formula ratemaking process to allow the recovery of costs more quickly.

"We knew that EIMA was bad for the ratepayers and obliterated any true regulation of ComEd as a utility," Neilan said. "We also knew that Speaker Madigan had crammed the legislation through the General Assembly; we just didn't know then that he did so as payback for numerous bribes ComEd had paid to his associates. But we know it now."

ComEd and Madigan did not immediately respond to a request for comment. ■

PJM News

PJM Operating Committee Briefs

Crews from PSE&G worked around the clock for several days to repair downed lines and other damage from Hurricane Isaias moving through the PJM region. | *PSE&G*

Manual 1 Changes for PMUs

Stakeholders at the PJM Operating Committee meeting on Thursday unanimously endorsed changes to Manual 1 to expand the use of synchrophasors and make them a requirement for certain projects under the Regional Transmission Expansion Plan (RTEP).

Shaun Murphy of PJM *reviewed* updates to the Control Center and Data Exchange Requirements section of *Manual 1* to include new language on required placement of synchrophasors, also known as phasor measurement units (PMUs). The revisions were first endorsed at the July 7 Planning Committee meeting after several months of debates. (See *PJM Stakeholders OK PMU Requirement*.)

Murphy said PJM wants to expand PMU deployments to gain full real-time observability of all equipment of 100 kV and above on the grid. He said PMUs provide the ability to detect equipment failures and high-speed grid disturbances such as oscillations and to allow for post-event analysis that includes a dynamic model validation.

"As the synchrophasor technology grows, the more and more it can be used," Murphy said.

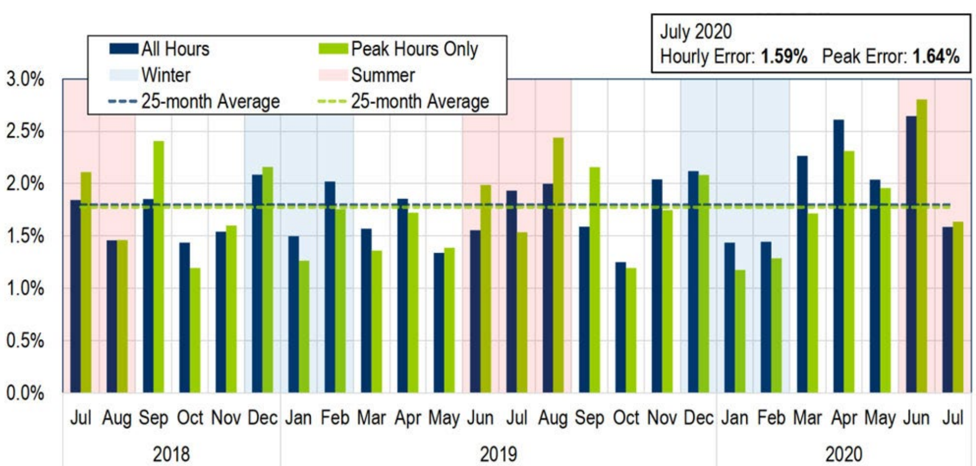
Costs for the synchrophasor installation is anticipated to run about $120,000 to make a substation "PMU ready," Murphy said, in addition to a $10,000 cost for a single PMU unit. PJM estimates annual costs of about $8 million for as many as 75 PMU installation projects each year, Murphy said, which is based on historical numbers of substation projects proposed in the RTEP process.

"We really think the benefits justify the additional costs," Murphy said.

Alex Stern, director of RTO strategy for PSEG Services, said he recognizes the benefits of having the PMUs installed in the system. But he said he thought the manual language could be "massaged further" through a friendly amendment to clarify the need to meet NERC standards in the RTEP process.

Dave Souder, PJM's senior director of system planning, said the RTO would be open to friendly amendments that strengthen the manual language if they don't change the intent of the process.

The Manual 1 changes now go to the Aug. 20 Markets and Reliability Committee meeting for a first read and a final vote at the September meeting.



Average load forecast error | *PJM*

Operating Metrics Review

Stephanie Monzon, markets coordination manager for PJM, *reviewed* the July operating metrics, pointing out three spinning events in a month marked by high temperatures across the RTO.

The three spinning events took place July 6, 23 and 25, Monzon said, lasting about 10 minutes each. Monzon said the spinning events were a response to "sudden generation loss."

Tier 2 penalties of 64.6 MW for the July 6 event and 37.5 MW for the July 25 event are being applied to the events, she said. "We had fairly decent Tier 2 response, but not exactly what we anticipated."

In the monthly balancing authority area control error limit (BAAL) performance score, PJM had 49 excursions outside the limits for a total of 124 excursion minutes. Monzon said none of the excursions exceeded the BAAL time limit and there was "nothing anomalous" to report.

The average load forecast error for all hours in July was 1.59%, Monzon said, while the error for peak hours was 1.64%. "We had a fairly good forecast error for July."

PJM recorded seven reserve sharing events with the Northeast Power Coordinating Council and had 31 post-contingency local load relief warnings and 15 hot weather alerts.

System Resilience Update

The last eight months have been a true test of the resilience of PJM's systems, said Chris Pilong, director of dispatch.

PJM News

Pilong noted that the COVID-19 pandemic forced the sequestration of control room operators at the PJM campus, which recently ended. He said the possibility of sequestration had been discussed hypothetically, but the plans had never been implemented.

He also pointed to the conversion of the simulator room into a third control room. PJM employees worked diligently to install the technology and security needed to make the room fully functional and to give the RTO more redundancy, he said.

PJM has continued posting best practices and lessons learned from the pandemic on its website. The RTO is also working with NERC and other reliability coordinators to help bring together industry-wide lessons learned on COVID-19 to prepare for any future pandemics, with work expected to ramp up in the fall, Pilong said.

Thursday's meeting was part of a "fitting week" to talk about resilience, Pilong said, with Hurricane Isaias moving through parts of the PJM region last Tuesday and a crash of the RTO's website last Monday night that took down functionality for stakeholders.

Pilong said that if a scenario would have been created a year ago that on one day the RTO would have to operate through a pandemic, a hurricane, flooding, seven tornados, power outages and IT issues all on the same day, it wouldn't have been believable.

"It's been an interesting week but another good chance to show the resilience of the system [and the ability of] PJM and its members to handle those things and recover," Pilong said.

Regulation Performance Update

Members challenged PJM's performance-based regulation market during a *presentation* by Gabrielle Genuario of the Performance Compliance Department. The challenges came during a discussion of how many times the system is automatically pegged, or fixed to a single value, for 20 to 30 minutes versus over 30 minutes.

PJM's performance-based regulation market splits the dispatch signal in two: RegA for slower-moving, longer-running units; and RegD for faster-responding units like batteries that operate for shorter periods.

Genuario said the automatic signal pegging has been "a little higher" over the last couple of months since the COVID-19 pandemic started. RegA saw 101 20- to 30-minute durations and 67 durations longer than 30 minutes in July. Those numbers compared to 40 20- to 30-minute durations and 17 durations longer than 30 minutes in July 2019.

RegD saw 10 20- to 30-minute durations in July, Genuario said, compared to three in July 2019.

One stakeholder said having the signal automatically pegged 10 times in a 31-day month is "not ideal" for RegD and called the 101 automatic signal pegs in RegA a "huge number." The stakeholder said they didn't understand how the incidents were linked to the pandemic.

Genuario said 15 hot-weather alerts and seven reserve sharing events helped skew the July numbers. Dispatchers are also seeing higher load forecast errors with the hotter summer weather.

"It doesn't seem to be a concern, but it's something we're definitely looking at," Genuario said.

The stakeholder said they didn't understand how the numbers couldn't be a concern for PJM. They said the automatic signal pegs had been brought up as a major issue in past years among stakeholders.

Glen Boyle of PJM said the RTO is not seeing the pegging translate into BAAL performance concerns. He said there are several variables in play, including issues with the load forecast and hot weather and the recent changeover on June 23 to the five-minute auto case execution for real-time security-constrained economic dispatch cases. (See *PJM Stakeholders OK 5-Minute Dispatch Proposal*.)

The stakeholder said PJM should possibly look at carrying additional reserves. "I would like to see us do something to get back down to the numbers we previously had if possible," they said. ■

— Michael Yoder

- RegD

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
20-30 min. duration	6	0	8	5	5	3	3	2	2	0	1	3	2	2	3	2	2	5	10
>30 min. duration	0	0	0	1	0	1	1	0	0	0	0	0	1	0	0	0	0	0	0

- RegA

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
20-30 min. duration	55	40	69	63	56	30	40	51	35	44	40	46	44	45	88	66	85	71	101
>30 min. duration	13	11	31	31	14	11	17	13	9	19	10	21	12	22	56	35	30	45	67

Automatic signal pegging frequency, January 2019 to July 2020 | *PJM*

SPP News

Evergy Releases Standalone Plan Details

By Tom Kleckner

Evergy confirmed Wednesday that it will remain independent and released details of the standalone plan that helped guide its decision.

CEO Terry Bassham told financial analysts during the company quarterly earnings call that Evergy's Sustainability Transformation Plan "sets the stage for significant value creation and a strong future for Evergy and our stakeholders."

The plan follows a "comprehensive, independent review" that began earlier this year and calls for $8.9 billion of capital investments in facility upgrades, grid modernization technologies and clean energy initiatives through 2024 in the company's Kansas and Missouri service territory.

"Our plan creates a compelling value proposition for shareholders," Bassham said. "Throughout the review, we were focused on three core objectives: maximizing long-term value for our shareholders, serving the best interests of all Evergy stakeholders, including our customers, employees and communities, and continuing to advance our work to successfully create a forward-thinking sustainable energy company."

The Kansas City-based company had explored possible purchases by a number of other companies. It called off the effort to remain a standalone company. (See Report: Evergy Calls Off Sale, Stock Slides.)

Bassham said Evergy considered a potential strategic combination and a "modified, improved" standalone operating plan and strategy. The board of directors and its strategic review committee each retained independent financial advisors and consultants to assist in the review.

Asked by an analyst whether Evergy received any purchase offers, Bassham only said the company did "engage with a number of third parties" during a "robust and comprehensive process."

"Without getting into a lot of the detail, in the end, the committee and the board both agreed that, based on that work and that review, our standalone plan produced a better long-term shareholder return profile and that was absolutely the best way to move forward," he said.

Evergy has become the nation's second-largest generator of wind energy as a percentage of total generation since 2005. The company has added or contracted for more than 4.6 GW of renewables and retired more than 2.4 GW of fossil generation. It said it can reduce CO_2 emissions by 85% before 2030, compared with 2005 levels.

The company will benefit from recent Kansas legislation that eliminates the state income tax for public electric utilities, effective Jan. 1. Bassham called the legislation "very positive" for Evergy's customers and communities.

Evergy CEO Terry Bassham | *Evergy*

Evergy reported second-quarter earnings of $133 million ($0.59/share), compared with $140 million ($0.57/share) a year ago. The company's operating earnings of $0.68/share just missed the Zacks consensus estimate of $0.70/share.

Evergy's stock price lost 3.38% Wednesday, falling $1.87 before closing at $53.53. ■

Evergy draws power from EDF Renewables' Slate Creek Wind Project. | *EDF Renewables*

SPP News

SPP to Develop NWPP Resource Adequacy Program

Program Will Help Address Pacific Northwest's Capacity Concerns

By Tom Kleckner

SPP and Northwest Power Pool said Monday they have agreed to work together in NWPP's development of a comprehensive resource adequacy program, further increasing SPP's presence in the Western Interconnection.

The two entities said SPP will act as the program director. The RTO will work with NWPP and its participating member utilities "to expand and refine" a preliminary design into a more comprehensive program.

NWPP began developing a capacity *resource adequacy program* late last year. Several studies have indicated near-term capacity deficits are expected in the Pacific Northwest, which is dominated by energy-limited hydropower and renewable resources. NWPP has also expressed concerns about a recent trend in decommissioning coal plants and expects to lose more than 2 GW of coal generation by 2023 and another 1.5 GW by 2029. (See *Western Resource Adequacy Program in the Works*.)

The corporation's president, Frank Afranji, said SPP's experience in developing and running a resource adequacy program across multiple states will help the organization reach the program's reliability objectives.

"The program we are developing will be available to participants with different needs and interests across a wide swath of the West," he said. "We believe SPP's multistate [resource adequacy] program experience will help us develop a program that provides benefits for all participants, as well as the region."

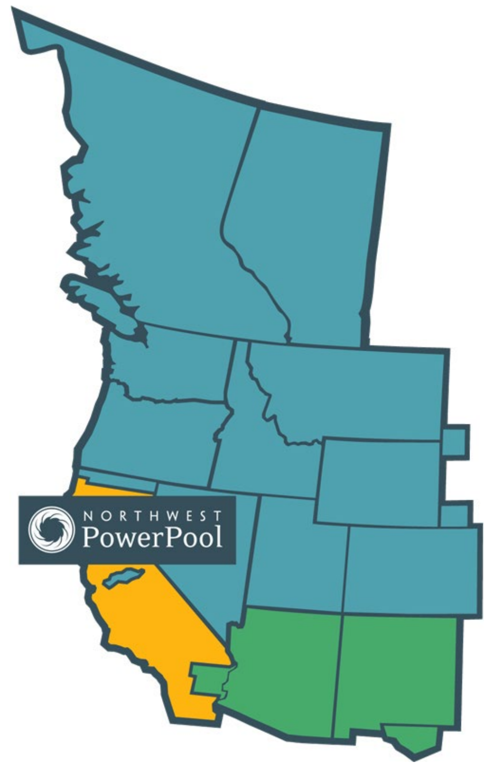
SPP CEO Barbara Sugg said the RTO would share with NWPP its "expertise in program design, development and administration as well as our experience working with stakeholders and regulators."

The RTO manages the grid across 17 central and western U.S. states and provides energy services on a contract basis to customers in both the Eastern and Western interconnections. It has been the reliability coordinator for 15 Western utilities since December and is hoping to stand up an energy imbalance service market for eight Western utilities in February, although it may be delayed. (See *FERC Rejects SPP's WEIS Tariff*.)

SPP staff will help design and develop the resource adequacy program. NWPP members will then competitively solicit a program administrator to implement and run the program.

Afranji said the program administrator will be a separate role. "We look forward to considering all candidates for this role in the future," he said. Those eligible to bid on the administrator role will include "SPP and any other qualified entity, including the NWPP and any others," he said.

A voluntary organization, NWPP provides professional and management services to its 18 participating organizations, comprising major generating utilities serving the northwestern U.S., British Columbia and Alberta. Smaller, mostly non-generating utilities in the region participate indirectly through the member system with which they are interconnected. ■



Northwest Power Pool's footprint (in blue) covers eight states and two Canadian provinces. | *NWPP*

Company Briefs

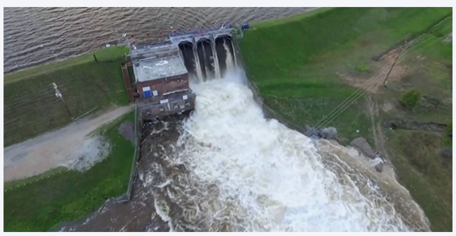
BP Reports Huge Loss, Vows to Increase Renewable Investment

BP reported a $16.8 billion quarterly loss last week and cut its dividend in half — the first reduction since the Deepwater Horizon disaster 10 years ago.

At the same time, CEO Bernard Looney said he intended for the company to invest about $5 billion a year for the next 10 years in renewable energy, about 10 times its current amount. He also said he wanted to reduce oil and gas production by about 40% in that time.

More: *The New York Times*

Edenville Dam Owners File for Bankruptcy



Boyce Hydro and Boyce Hydro Power, the owners of four Michigan dams, filed for Chapter 11 bankruptcy protection last week.

Boyce Hydro Power claimed revenue of $1.6 million and $2.1 million in expenses. It owes its 20 largest creditors more than $7 million, including $6.1 million from a Chicago bank loan.

The companies own the Edenville Dam, which failed in May. The flood caused about $200 million in damages and spurred lawsuits, including one seeking $500 million.

More: *Bridge Michigan*

Equitrans Confirms Early 2021 Startup for Gas Pipeline

Equitrans Midstream last week said it still expects to complete the $5.4 billion Mountain Valley natural gas pipeline from West Virginia to Virginia in early 2021. Mountain Valley is one of several U.S. oil and gas pipelines delayed by regulatory and legal fights with environmental groups that found problems with federal permits issued by the Trump administration.

The company said the project's costs could rise by 5% to about $5.7 billion if it needs "to adapt the construction plan for potential complex judicial decisions and regulatory changes."

More: *Reuters*

Facebook Inks PPA with Apex Clean Energy

Facebook last week announced it had signed a power purchase agreement with Apex Clean Energy for a 170-MW portion of the 300-MW Lincoln Land Wind project in Illinois. It is Facebook's third renewable energy transaction with Apex in the past year.

The project will be built in Morgan County, where it should begin commercial operations next year. The length and financials of the deal were not disclosed.

More: *Renewables Now*

FERC Upholds PJM Tx Cost Assignments

FERC last week rejected rehearing and clarification requests on two orders issued in April directing PJM to rebill parties to reverse incorrect cost assignments for transmission projects to meet individual utilities' Form 715 planning criteria.

In 2015, the commission approved a PJM Tariff change that assigned 100% of the costs of Form 715 transmission projects to the sponsoring utility's ratepayers. But FERC reversed itself in August 2019 after the D.C. Circuit Court of Appeals said it had erred. In April, the commission rejected rehearing on its 2019 order and clarified that PJM should issue refunds dating back to May 25, 2015, with interest. (See *FERC Stands Firm on Form 715 Assessments*.)

In the order, the commission rejected rehearing and clarification requests by PPL, Dayton Power & Light, Long Island Power Authority, Neptune Regional Transmission System and Linden VFT regarding the April orders as improper collateral attacks or outside the scope of the dockets.

More: *ER15-1387-007, ER15-1344-008*

First Solar Plants to be 100% Renewable-powered by 2028

First Solar last week said it plans to reach a 100% renewable power supply for its global manufacturing operations by 2028. Additionally, it has set an interim goal to use carbon-free electricity in all U.S. facilities by 2026.

The company said its module technology already has a carbon footprint up to six times lower than that of crystalline silicon PV panels, but it still expects to further reduce their carbon emissions by 40% by 2028.

More: *Renewables Now*

First Solar to Sell O&M Business to NovaSource

First Solar last week agreed to sell its North American operations and maintenance business to NovaSource Power Services, the company formed from SunPower's O&M business, as part of a streamlining plan to focus making thin-film solar modules. The company has also launched a "strategic evaluation" of divesting its project development arm.

CEO Mark Widmar said the decision was driven by expectations of a more challenging environment for a business that is seeing increased competition and reduced power purchase agreement prices for the solar projects it serves. In 2017, First Solar's O&M business was seeing more than 30% gross margins driven by legacy contracts. Since then, competitive pressure and falling PPA prices have driven those margins closer to 10%.

More: *GreenTech Media*

Electric-truck Maker Lordstown Going Public

Electric-truck maker Lordstown Motors last week announced it will merge with DiamondPeak Holdings in a deal that will make it a publicly traded company.

The deal will add $675 million to Lordstown's reserves and boost its valuation to $1.6 billion. It includes a fully committed $500 million private investment in public equity, with $75 million from General Motors.

The combined company is expected to be listed on the NASDAQ under the new ticker symbol "RIDE." The transaction is expect to close in September or October, a Lordstown spokesman said.

More: *Detroit Free Press*

PG&E Ordered to Bolster Line Inspections, Tree Trimming

U.S. District Judge William Alsup last week ordered Pacific Gas and Electric to hire new tree-trimming supervisors, improve records about the age of electrical equipment and bolster the way it inspects high-voltage lines. The mandates are additional conditions to PG&E's probation arising from the 2010 San Bruno gas pipeline explosion.

By Sept. 1, PG&E must hire a vegetation management inspection manager to oversee contractors who cut branches and trees. Then, starting at the end of September through January 2021, PG&E must hire 30 workers to "conduct in-field oversight of contractors while the work is being performed, verifying and correcting any deviation from applicable scopes of work pursuant to PG&E policies and legal requirements."

The utility must also "conduct a reasonable search" for records about the age and installation date for certain tower equipment in high-threat areas.

More: *San Francisco Chronicle*

SOO Green Opening Solicitation Process for Tx Line

SOO Green HVDC Link last week opened the solicitation process to allocate transmission capacity rights on its planned line to link MISO's and PJM's energy markets.

FERC approved SOO Green's request on July 23 to charge negotiated rates on its proposed 350-mile, 2,100-MW transmission line, which the developer hopes to use to deliver renewable energy from upper MISO to PJM's territory in Illinois (*ER20-1665*). (See *FERC Oks Negotiated Rates for Merchant Tx Line*.) In June, PJM stakeholders agreed to consider integrating HVDC converters as a new type of capacity resource at SOO Green's request. (See *HVDC Initiative Endorsed by PJM Stakeholders*.)

The line is planned to run underground, primarily along existing rail rights of way from Mason City, Iowa, to Plano, Ill. Construction on the $2.5 billion project is expected to begin in early 2022 and be completed by 2024.

More: *SOO Green*

SunPower Tops Q2 Revenue Forecast

SunPower last week posted a 19% year-on-year drop in GAAP revenue to $352.9 million, although the total was more than the $290 million to $330 million range given by the company in May.

Adjusted earnings were negative, as expected, at $8.9 million. Still, the loss was significantly below the projected range of $20 million to $40 million.

For the third quarter, SunPower anticipates revenue of $360 million to $400 million and a net loss of $95 million to $110 million.

More: *Renewables Now*

Vectren Rebranding to Refocus on Utility Business

Vectren, a CenterPoint Energy Company, said last week it will rebrand under the name CenterPoint Energy in the coming months as part of its continued focus on its utility strategies. The rebranding will take several months to complete.

CenterPoint finalized its merger with Vectren in February 2019. Since then, the company has been operating under the long, joint name.

According to the company, the rebrand will include new signs and markings, but the same employees will represent the organization.

More: *Evansville Courier & Press*

WEC Energy Group Pledges Carbon Neutrality by 2050

WEC Energy Group, which owns We Energies and Wisconsin Public Service, last week pledged to be carbon-neutral by 2050.

The company has set a new goal to reduce carbon emissions by 70% in the next decade after exceeding its previous goal to cut emissions by 40%. It also plans to spend $900 million on renewable energy generation in Wisconsin over the next four years. The company also assumes emissions from newer power plants will be offset through carbon capture or other means.

Despite its pledge, the company isn't announcing plans to replace or close any of its coal-fired power plants in Wisconsin.

More: *Wisconsin Public Radio*

Fermi 2 Nuclear Plant Emerges from Outage

DTE Energy's Fermi 2 nuclear plant emerged from a long refueling and maintenance outage last week and was at 19% power as of Aug. 4. The shutdown, which normally lasts about a month, has taken nearly five months.

The delay was not exclusively because of the COVID-19 pandemic, but DTE spokesman Stephen Tait confirmed the virus did complicate efforts with an outbreak shortly after the maintenance outage began March 21.

Fermi 2's outage is thought to be the nation's longest this year. The Nuclear Regulatory Commission could neither confirm nor deny the statement, stating it doesn't keep such records handy.

More: *The Blade*

Federal Briefs

DC Circuit Says Dakota Access Can Keep Operating

The D.C. Circuit Court of Appeals last week threw out the order issued last month by U.S. District Judge **James Boasberg** shutting down the Dakota Access Pipeline, saying he "did not make the findings necessary" to justify his ruling. Boasberg ordered the pipeline be emptied of oil within 30 days, prompting an appeal by developer Energy Transfer and the Army Corps of Engineers, which permitted the line.

The appeals court did keep in place Boasberg's March decision revoking the corps' permit for the pipeline's Missouri River crossing in North Dakota just upstream from the Standing Rock Sioux Reservation. The court said the corps will need to make a decision on whether the pipeline should keep operating while the permit remains invalid. It remanded the matter to Boasberg, who likely will hear from the agency, pipeline company and tribes in the weeks ahead.

More: *The Bismarck Tribune*

Court Extends Blackjewel Bankruptcy Case

A federal judge last week extended the deadline for bankrupt coal operator Blackjewel to finalize its plan for Chapter 11 bankruptcy reorganization to Sept. 25, according to documents filed July 27. The plan is required before Blackjewel can formally exit bankruptcy.

After the plan is submitted, creditors will have until Dec. 23 to vote on the proposal. More than 2,800 claims have been filed since the case began.

More: *Casper Star-Tribune*

Snake River Dams will not be Removed

The Army Corps of Engineers, Bureau of Reclamation and Bonneville Power Administration last week issued a final environmental impact statement and said the four hydroelectric dams on the Snake River in Washington state will not be removed to help endangered salmon migrate to the ocean. Instead, a plan calls for spilling more water over the dams at strategic times to help the fish migrate faster.

The dams were built in the 1960s and 1970s between Pasco and Pomeroy. Since then, salmon populations have plunged, while the Pacific Northwest orca was placed on the endangered species list in 2005, as chinook salmon are its primary food source. The dams have fish ladders that allow some salmon and other species to migrate to the ocean and then back to spawning grounds, but most of the fish die during the journey.

A record of decision will be released in September.

More: *The Associated Press*

Trump Forbids Agencies from Outsourcing Jobs

President Trump last week signed an executive order forbidding federal agencies from outsourcing jobs overseas and fired Tennessee Valley Authority board of directors Chair James "Skip" Thompson and Director Richard Howorth.

"Let this serve as a warning to any federally appointed board: If you betray American workers, you will hear two words: 'You're fired,'" Trump said. He also pushed for the board to remove CEO Jeff Lyash.

The moves are a result of the TVA outsourcing at least 120 information technology jobs to three software development contractors headquartered outside of the U.S. The utility gave formal notice to 62 IT workers in Chattanooga and Knoxville in June that their jobs were ending in 90 days as it continued to outsource more data and programming work.

However, just three days after Trump signed the order, TVA rehired 102 tech workers, saying the company was "wrong in not fully understanding the impact on our employees" and was "taking immediate actions to address this situation." TVA also said it "fully understands and supports the administration's commitment to preserving and growing American jobs."

More: *Knoxville News Sentinel*; *The Associated Press*; *The Washington Post*

PREPA CEO Resigns amid Outages

Puerto Rico Electric Power Authority CEO José Ortiz stepped down last week amid widespread anger with ongoing power outages occurring during the COVID-19 pandemic at the height of hurricane season.

As of Aug. 3, more than 20,000 customers remained without electricity after Tropical Storm Isaias swept through the territory. That only added to the 300,000 who were without power from the week before because of a non-storm related power outage.

Ortiz had become the company's third CEO in two weeks when he was appointed in July 2018 as the territory struggled to recover from a lack of leadership, bankruptcy and outages caused by Hurricane Maria in 2017.

More: *The Associated Press*

State Briefs

ARKANSAS

PSC Rejects Entergy's Revised Solar Power Offering

The Public Service Commission last week rejected Entergy Arkansas' proposal to offer discount solar power to local governments, schools and non-taxed entities.

The utility had revised the proposal after the PSC originally rejected it in June. But the commission agreed with staff that the revised proposal must state that power will come from Entergy's Stuttgart Solar facility, rather than using a "designated solar resource," which "suggests that approval of the commission is not required." The PSC also agreed that any revised rider must include a provision that nonparticipants in the purchase plan should retain the renewable energy certificates associated with the solar resource. It also found that the company failed to provide options for low-income participation.

Entergy plans to present modifications to the commission by the end of the month.

More: *Arkansas Business*

CALIFORNIA

SoCalGas Sues CEC over Failure to Promote Natural Gas

Southern California Gas filed a lawsuit against the Energy Commission in Orange County Superior Court, saying that it has failed to promote natural gas as required by state law.

Lawmakers approved the Natural Gas Act in 2013 and required the commission to "identify strategies to maximize the benefits obtained from natural gas as an energy source" every four years. The commission did so in 2015, but SoCalGas says the commission failed to meet its obligation in 2019 when it issued a smaller 22-page appendix to a larger energy policy document.

A separate lawsuit was filed against the Air Resources Board by the California Natural Gas Vehicle Coalition, whose two charter members are SoCalGas and Clean Energy Fuels, which also joined SoCalGas in its lawsuit against the CEC. This lawsuit seeks to overturn a newly approved "advanced clean trucks" rule, which hopes to put 300,000 zero-emission trucks on the road by 2035.

More: *Los Angeles Times*

INDIANA

NIPSCO Hit with $1.1M in Fines for Pipeline Safety Violations

The Utility Regulatory Commission last week said it will fine Northern Indiana Public Service Co. $1.1 million for instances of failing to locate or mark underground pipelines within two days of a request being made, as required by safety procedures in advance of any excavation work. The order also mandates that none of the penalty can be recovered from NIPSCO's customers.

It is the largest fine in state history. In 2017, NIPSCO paid $900,000 in civil penalties for past pipeline violations that stretched back to 2015. At the time, the utility agreed to pay higher civil penalties for any similar violations in the future.

"We acknowledge the fine and pledge to correct any issues pertaining to line locates," a NISPCO spokesperson said. "The violation addresses a very small number of instances in which NIPSCO failed to locate or provide an accurate locate for underground utilities when requested by someone doing excavation work."

More: *The Northwest Indiana Times*

MINNESOTA

Minnesota Power Gets Energy Plan Extension

The Public Utilities Commission issued Minnesota Power a four-month extension to prepare its next required energy plan. The company, which will have to submit interim reports in the fall, now has until Feb. 1 to announce its 15-year plan.

The utility said the extension was necessary because the COVID-19 pandemic interrupted stakeholder engagement plans and made the Oct. 1 deadline unrealistic. The plan will outline its expected energy demands and sources, as well the future of its Boswell coal-fired plants.

More: *Duluth News Tribune*

MISSISSIPPI

Solar Facilities Approved in Hancock, Clarke Counties

Public Service Commission Chairman Dane Maxwell drafted orders last week that would allow developers of the Moonshot Solar project in Hancock County and the

Cane Creek Solar project in Clarke County to move forward.

The projects would bring separate 78.5-MW generating stations to each county that would deliver wholesale power directly to Mississippi Power.

More: *The Associated Press*

NORTH CAROLINA

Isaias Forces Brunswick Nuclear Reactor to Shut Down

Hurricane Isaias last week knocked out power to the region, including a major line providing power to the Brunswick Nuclear Plant.

The storm took out a main line and caused a loss of off-site power to the facility. As a precaution, power to one of the plant's two reactors was shut down.

Karen Williams, a spokesperson for the plant, said customers should not be impacted.

More: *WWAY*

NEW MEXICO

FERC OKs Negotiated Rates for Tx Lines

The proposed Lucky Corridor and Mora Line merchant transmission lines may continue to sell access at negotiated rates following their purchase by Ameren Transmission, FERC ruled Aug. 4. The commission also approved the lines' proposed capacity allocation process, subject to submission of a post-allocation compliance filing, and accepted their post-selection open solicitation report.

The Lucky Corridor Project is a 62-mile, 345-kV line between Tri-State Generation and Transmission Association's Springer and Taos substations, with potential delivery to Public Service Company of New Mexico's Ojo substation via existing transmission. The Mora Line is a 180-MW line between Tri-State's Gladstone and Storrie Lake substations and PNM's Arriba substation. The projects are intended to deliver new economic renewable energy resources to the Four Corners market hub and other Western markets.

FERC initially granted Lucky Corridor permission to sell at negotiated rates in 2012.

More: *ER20-1976*

VIRGINIA

Legislators Urge State to Suspend Pipeline Construction

Twenty-two legislators last week jointly signed a letter urging Gov. **Ralph Northam** and health officials to halt construction on the Mountain Valley Pipeline during the COVID-19 pandemic. The letter comes after pipeline developers announced it intends to bring in more than 4,000 workers to work on the project.

"An influx of thousands of workers for a project whose completion will not benefit Virginians will needlessly risk accelerating the pandemic in an area of the commonwealth with already limited health care resources," Del. Chris Hurst said.

More: *WFXR*

WYOMING

Carbon County Approves Tx Line

The Carbon County Planning and Zoning Commission last week unanimously voted to recommend the approval of a permit for PacifiCorp to construct its 416-mile Gateway South transmission line. Although the commission endorsed the conditional-use permit, the county's Board of Commissioners will need to extend final approval to the project.

The line would help Rocky Mountain Power, a division of PacifiCorp, meet increasing demand for energy across the West.

The board will consider the project at its upcoming Sept. 1 meeting. The Industrial Siting Council will host a hearing on Oct. 21

to consider the utility's application for a Section 109 permit to construct and operate the project.

More: *Casper Star-Tribune*

Laramie Moves Forward on Solar Development

The Laramie City Council last week unanimously voted to approve a lease agreement and memorandum of understanding between the city and Boulevard Associates — an affiliate of NextEra Energy — for the development of a solar energy center on the Monolith Ranch. The council's approval allows the company to submit a proposal to prove site control that could move the project into the next stages.

The agreement includes a four-year lease term with a potential two-year extension to NextEra for about 2,400 acres on the ranch. With the lease, NextEra can begin evaluating where to place a potential 160-MW solar facility with an associated 80 MW of storage.

More: *Laramie Boomerang*