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Your Eyes and Ears on the Organized Electric Markets
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Climate Policy on the Ballot Today

State Voters to Choose Regulators, Clean Energy Targets

By Rich Heidorn Jr. and Hudson Sangree

Although the coronavirus pandemic has sucked up most of the oxygen in this year's presidential and congressional races, West Coast wildfires, record-breaking heat waves and more than two dozen tropical storms have also made climate change an issue impossible for voters to ignore.

A victory by former Vice President Joe Biden and a Democratic pickup of three Senate seats would reassert the U.S.' commitment to the Paris Agreement on climate change and give the party a shot at enacting legislation to meet the agreement's targets. President Trump's re-election — even if he faces a hostile Senate — would likely mean four more years of climate denialism and regulatory rollbacks. *The Washington Post* reported last week that Trump had "weakened or wiped out more than 125 rules and policies aimed at protecting the nation's air, water and land, with 40 more rollbacks underway."

Regardless of what happens in D.C., however, state officials are likely to continue pursuing their own clean energy targets. In addition to races in 86 of the 99 state legislative chambers and 11 gubernatorial contests, state regulators are facing re-election from Georgia to Montana, with a climate-related measure on the ballot in Nevada.

Biden Plan

In July, Biden outlined a $2 trillion plan to

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FirstEnergy Fires Jones over Bribe Probe

Former FirstEnergy CEO Charles Jones gives a shareholder address in 2018. (p.47) | © *RTO Insider*

FERC Pushed to Change Tx Rules for OSW

Interconnection Queue, Cost Allocation Seen as Obstacles

By Michael Yoder, Jason York, Michael Kuser and Rich Heidorn Jr.

Efficient development of offshore wind transmission will require changes to current planning, interconnection and cost allocation procedures, speakers told FERC on Oct. 27 in a daylong technical conference (AD20-18).

RTO officials agreed with wind developers and others that while the first few OSW projects are progressing through interconnection queues, the current process does not allow the coordinated planning needed to maximize the limited number of good interconnection points on shore.

Speakers also said cost allocation rules don't properly assign costs to parties that will benefit from the additional offshore and onshore transmission that will be required for states to meet their clean energy goals and OSW targets.

Transmission Queue Process

"The current RTO/ISO planning and cost allocation methods generally hinder the integration of offshore wind on a large scale," said Anne Marie McShea of Ocean Winds North America, a joint venture of EDP Renewables and ENGIE, which has a 50% stake in the Mayflower Wind project off Massachusetts.

McShea, head of offshore wind business development for New York and the Mid-Atlantic region, said that PJM, NYISO and ISO-NE are overly reliant on the interconnection queue to determine transmission needs, and that they evaluate transmission needed for reliability, market efficiency, resilience and public policy "in an unintegrated manner."

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eliminate power sector carbon emissions by 2035 and make the U.S. the leader in electric vehicle production, calling the climate change challenge a "once-in-a-lifetime opportunity to jolt new life into our economy, strengthen our global leadership [and] protect our planet for future generations." (See *Biden Offers $2 Trillion Climate Plan*.)

Biden pledged to build on the billions in clean energy investments of the Obama administration and reverse the Trump administration's environmental rollbacks. The Democratic candidate's proposal was developed with input from former presidential candidates Sen. Bernie Sanders (I-Vt.) and Gov. Jay Inslee (D-Wash.) and is markedly more ambitious than the policies he backed during the primaries, when he called for spending $1.7 trillion over 10 years and eliminating CO_2 emissions from power plants by 2050.

The shift reflects both his desire to motivate the liberal wing of the Democratic Party and to provide an economic stimulus to aid recovery from the pandemic. "We're not just going to tinker around the edges," he promised. "Science tells us we have nine years [to cut emissions] before the damage is irreversible, so my timetable [for] results is my first four years as president."

The plan proposes funding to support EVs, improve energy efficiency and reduce the costs of clean energy technologies. Seeking to head off criticism that the plan will harm the economy, Biden framed his proposal as an economic development program, repeatedly referring to creation of "union" jobs.

President Trump pledged to withdraw the U.S. from the Paris Agreement on climate change in 2017. The withdrawal will be effective tomorrow. | *© RTO Insider*

Fracking an Issue in Pa.

During repeated campaign visits to the crucial state of Pennsylvania, Trump has warned that the former vice president will seek to eliminate fracking. Biden has denied the claim, saying only that he will end subsidies for fossil fuels and stop issuing new drilling permits on federal lands and waters.

ClearView Energy Partners calculated that the 10 counties responsible for 91% of Pennsylvania's natural gas production had a significant role in Trump's narrow 2016 win in the state. Except for Allegheny County, home to Pittsburgh, all of the top gas-producing counties voted for Trump, who added almost 31,000 votes to the total that GOP candidate Mitt Romney received in 2012. Trump won the state by less than 45,000 votes out of more than 6 million cast, a difference of 0.72%. Pennsylvania holds 20 of the 270 Electoral College votes needed to win the presidency.

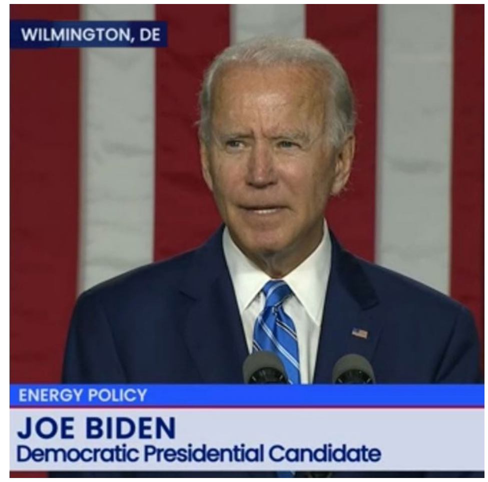
Congress

Democrats are expected to hold or increase their current *232-197* edge in the House of Representatives. (There are also five vacancies and one Libertarian.) But approving legislation to implement Biden's plans would likely require them to take control of the Senate, now held by Republicans 53-47, including two independents who caucus with the Democrats.

Polling *indicates* the Democrats will likely lose a seat in Alabama but gain one each in Colorado and Arizona. Democratic candidates also are within reach in toss-up races in Maine, North Carolina, Iowa, Georgia, South Carolina and Montana. A blue wave could also threaten Republican seats in Kansas, Texas, Alaska and Georgia's second seat.

FERC

A Biden win also would give Democrats control over three of FERC's five commission seats once Republican Chairman Neil Chatterjee's term expires June 30, 2021. Democratic Commissioner Richard Glick has repeatedly clashed with Chatterjee and other Republicans over their approvals of natural gas infrastructure and rulings subjecting state-subsidized re-



Democratic presidential nominee Joe Biden announced his climate plan in a speech at the Chase Center in Wilmington, Del. | *C-SPAN*

newables in PJM and NYISO to minimum price floors, harming their ability to compete in RTO capacity markets. But Glick joined Chatterjee last month in proposing a policy statement inviting states to introduce carbon pricing in the RTO markets. (See *FERC: Send Us Your Carbon Pricing Plans*.)

The commission is currently controlled 2-1 by Republicans. In July, Trump nominated Democrat Allison Clements, energy policy adviser for the Energy Foundation, and Republican Mark Christie, chair of the Virginia State Corporation Commission, to fill the two vacancies. (See *FERC Nominees Bob and Weave Through Senate Hearing*.)

Arizona Corporation Commission

In the West, Nevada voters will decide whether to require half the state's electricity to come from clean energy resources by 2030, and voters in Arizona, Montana and New Mexico will vote for utility regulators in contentious races that could determine their states' energy futures.

Three of the seats on the five-member Arizona Corporation Commission are up for grabs today, with only one incumbent on the ballot.

The commission, which regulates utilities and rates, voted Thursday to make the state the latest in the West to follow California's lead and adopt a 100% clean energy mandate by mid-century. New Mexico and Washington

FERC/Federal News

have similar mandates approved by lawmakers.

The commission, which has four Republicans and one Democrat, voted 3-2. Chairman Bob Burns and Commissioner Boyd Dunn, neither of whom is seeking re-election, voted with Democrat Sandra Kennedy in support of the measure.

"The climate crisis is impacting Arizonans right now," Kennedy said in a statement after the vote. "I am glad the commission was finally able to look past partisan politics to support science and economics-based policy that stakeholders, utilities and ratepayers could all agree upon and benefit from."

The question of renewable energy and California's influence on the more conservative Arizona has been a major source of contention in state politics and the utility industry.

Arizonans voted overwhelmingly in 2018 to reject Proposition 127, a measure that would have required the state's power providers to generate at least half their annual sales of electricity from renewable resources by 2030. The race became a high-priced battle between California billionaire Tom Steyer, whose environmental advocacy group NextGen America backed the proposal, and Arizona Public Service (APS), which spent more than $50 million in the fight. (See *High Failure Rate for Western Ballot Measures*.)

Critics say APS has too much influence on commissioners, including through campaign contributions.

Six candidates are seeking the seats held by Burns, Dunn and Republican Lea Marquez Peterson — the only incumbent on the ballot.

The Washington Post *reported* Friday that billionaire and former New York City Mayor Michael Bloomberg, an advocate of carbon-free energy, had contributed $6.3 million to the three Democrats running: William "Bill" Mundell, Shea Stanfield and Anna Tovar. Two Republicans, Jim O'Connor and Eric Sloan, are also on the ballot.

The three leading vote-getters will join Kennedy and Justin Olson on the commission.

Arizona is one of 11 states where utility regulators are elected, not appointed by a governor or lawmakers. Also facing elections today, according to *Ballotpedia*, are regulatory commissioners in Alabama, Georgia, Louisiana, Montana, Nebraska, New Mexico, North Dakota, Oklahoma and South Dakota. (The 11th, Mississippi, elects its state officials in odd-numbered years, always in the year preceding the presidential election.)

The Montana race features Democrats running for two open seats on the all-Republican Public Service Commission, which has been plagued by infighting and scandal in recent years, the *Montana Free Press* reported. The commission's support of coal power is out of sync with the growing progressive populations of cities such as Missoula and Bozeman, making change in the commission's makeup and state energy policies a possibility this year.

New Mexico PRC

In New Mexico, lawmakers placed a constitutional amendment on the ballot that would shake up the state's Public Regulation Commission by letting the governor appoint three at-large members in place of the five members now elected by geographic district. Both Republican and Democratic lawmakers overwhelmingly backed the ballot measure, and Gov. Michelle Lujan Grisham (D) supports it.

Many elected officials were angry with PRC commissioners for what they called an attempt to skirt the state's landmark 2019 Energy Transition Act, signed by Lujan Grisham, which requires the state's investor-owned utilities to get all their electricity from carbon-free sources by 2045. (See *New Mexico Moves Toward Clean Energy, EIM Participation*.)

Two current members of the PRC — Cynthia Hall and Stephen Fischmann — back the amendment, saying some of those elected to the PRC lack the backgrounds needed to understand complex regulatory issues.

Other members of the PRC argue that allowing the governor to appoint its members would deprive voters, especially those in rural disadvantaged communities, of the opportunity to influence ratemaking and policy decisions. (See *Energy Amendments on NM, Nevada Ballots*.)

Nevada Question 6

Nevada's Question 6 asks voters for the second time in two years whether the state should make clean energy goals a part of its constitution.

A law signed by Gov. Steve Sisolak (D) in April 2019 requires the state to get half its electricity from non-carbon-emitting resources by 2030, but environmentalists worry it could be overturned by elected officials if the political winds shift.

Amendments to Nevada's constitution must be approved in two consecutive elections, so the question faces a final vote this year after winning 59% support in 2018. That effort, like the current one, was bankrolled by Steyer. ■

Renewable energy policy, via regulator elections and voter initiatives, is on the ballots of Western states today. | *Bureau of Land Management*

FERC/Federal News

FERC Pushed to Change Tx Rules for OSW

Interconnection Queue, Cost Allocation Seen as Obstacles

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PJM's Regional Transmission Expansion Plan, she noted, uses a 15-year planning horizon and considers changes to the generation mix based on the interconnection queue. "This analysis does not reflect the true mix of resources that will be relied upon by, say, 2030," she said, adding that FERC should require RTOs to reflect state OSW procurement targets and solicitation schedules in their transmission plans.

"The interconnection process is a very incremental process that cannot efficiently identify low-cost interconnection points nor identify low-cost transmission solutions that work for this scale," The Brattle Group's Johannes Pfeifenberger said. "One project at a time simply won't get that kind of transmission built."

Pfeifenberger estimated that PJM, ISO-NE and NYISO will have to spend about $10 billion in onshore transmission upgrades to accommodate the 15 to 20 GW of renewables that their states already require.

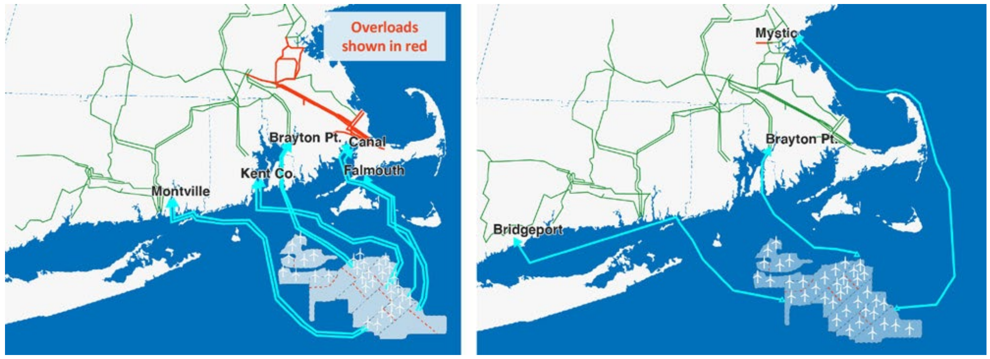
"If you look at the PJM interconnection queue, after the first couple thousand megawatts, you hit $1 [billion to] $3 billion in already identified onshore upgrades. … We might find that we have to upgrade all the medium-voltage transmission lines along the coast to 500 kV. … I'm afraid that the onshore bottlenecks will create the biggest uncertainty and the biggest risk for cost-effective offshore wind," he said.

"We cannot afford to develop the offshore transmission grid in piecemeal," agreed Judy Chang, Massachusetts' undersecretary of energy, saying the load growth expected from decarbonizing the economy and electrifying buildings and transportation calls for "a paradigm shift" in transmission planning.

"The old principles are not valid anymore. The changes that our electric grid [needs] blur the lines between what is reliability needs versus … congestion relief and public policy needs," she said.

James Cotter of Shell New Energies, which has investments in the Mayflower and Atlantic Shores offshore projects, said he fears that the current approach to transmission may limit offshore wind installations to 4 to 5 GW on the East Coast and prevent development on the West Coast.

PJM and ISO-NE officials agreed on the need to make changes to accommodate OSW.

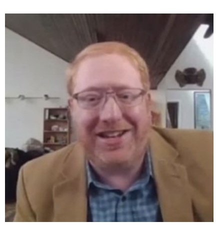


Generator lead line vs. planned mesh network for New York | *The Brattle Group*


Ken Seiler, PJM | *FERC*

"To date, PJM's existing interconnection queue process has provided a useful tool for helping begin to achieve the states' renewable targets through onshore renewables and provide a path for some offshore projects," said Ken Seiler, PJM's vice president of planning. "However, PJM anticipates that as the scale of offshore wind projects increases — and the scope of the transmission upgrades necessary to integrate offshore wind generation grows in complexity and cost — the traditional interconnection queue construct may not be sufficient, and PJM may need to develop alternative mechanisms to accomplish the required transmission buildout."

He cited limited points of entry from the ocean and limited transfer capability to reach load centers.


Abe Silverman, NJBPU | *FERC*

Abe Silverman, general counsel for the New Jersey Board of Public Utilities, noted that PJM's transmission planning has generally assumed West-to-East flows of power. As a result, he said, transmission near New Jersey's shore is less robust than it is in more inland areas, and the state's 500-kV generally runs North-South, about 40 miles inland. "The fact is that large portions of the existing grid along the coast are not designed to accommodate injections associated with a large amount of offshore wind, and so we need to find a way to efficiently get the power from shore to the backbone of the PJM system," he said.

Silverman called for a "bold vision" to rethink OSW planning, citing as examples the Competitive Renewable Energy Zone project in Texas and the Tehachapi transmission line in California. New Jersey hopes to have 7,500 MW of OSW by 2035, with solicitations every 18 months to two years between now and 2028.

Robert Ethier, vice president of system planning for ISO-NE, said the RTO's planning process is functioning "pretty well" with system impact studies complete for more than 3,900 MW of offshore wind. He said interconnection agreements are ready to be signed with TOs and construction can start on projects.

"As we reach the limits of the current system and have to start building out the onshore infrastructure to accommodate the new offshore infrastructure, almost certainly it's going to make sense to do big projects that would facilitate lots of interconnection at one time," Ethier said.

He also noted that the region will need to align its short-term transmission needs with its longer-term goals. "I think it's important that these two processes become one process or at the very least talk to one another."

Zachary Smith, vice president of system and resource planning for NYISO, cited the "flexibility" in the ISO's planning process. "Once solutions come forward, we have many ways to look at them, not just in a single silo of reliability, economic and public policy," he said. "That approach has served us quite well in New York."

Don't Move the Goalposts

Gabe Tabak, counsel for the American Wind

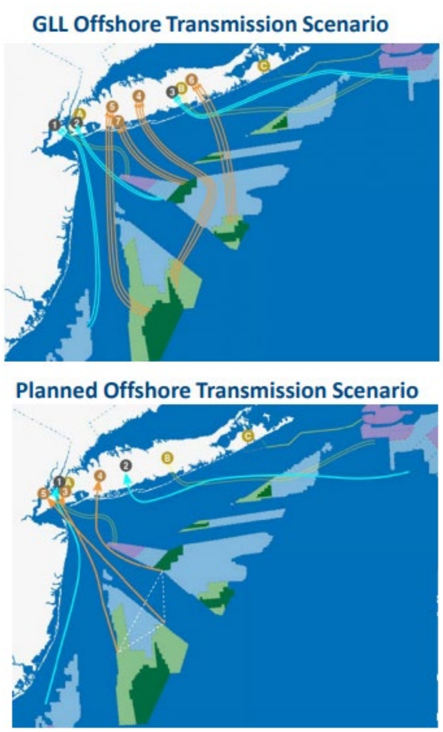
FERC/Federal News

Energy Association, called for flexible planning and interconnection policies so they can react to the rapidly evolving "policy drivers, economic imperatives and technological innovations."

Policy should balance the needs of projects in various stages of development, he said. "The commission should ensure that changes in transmission planning or interconnection rules allow projects that are currently well underway to proceed without shifting the goalposts. This principle also means that any longer-term planned offshore transmission system — which most members agree would be needed to attain the 29 GW of Eastern state goals — should have adequate lead time to ensure that later projects are not subject to excessive upgrade costs."

Tabak called on FERC to conduct "a holistic examination of renewable energy integration strategies," citing the interplay between offshore and onshore integration policies.

"Many of the topics discussed today — including the role of state policies, the potential role of a 'transmission first' model, the benefits of transmission, modeling of inverter-based generation and transmission approaches from other jurisdictions — are not confined to the offshore context. The rapid growth and potential of offshore wind provides an opportunity for fresh evaluation of transmission planning, cost allocation and interconnection rules in other contexts."



Generator lead line vs. planned mesh network for New England | *The Brattle Group*

'Transmission First' Model, Merchant Transmission

McShea also called for continuity, saying projects already underway using radial interconnection should not be delayed by the adoption of other models. But she said the "transmission first" model — in which large-scale transmission facilities are built for anticipated generation to achieve economies of scale — will be needed for future projects.

The commission said its current regulations do not include a transmission first approach "except perhaps the merchant transmission framework."

A transmission first model also would require changes to cost allocation rules, McShea said, noting that PJM's "state agreement" approach assigns all transmission costs to the sponsoring state even when the transmission may also benefit its neighbors. She called for cost allocation based on a broader set of criteria including contributions of the project to system reliability, operational performance, economics and resilience in addition to "public policy" goals.

Former FERC Chair Jon Wellinghoff, now a consultant, said merchant transmission development is not well suited for OSW because developers will have difficulty raising financing without guarantees that generators will support their project. He cited the failure of the Atlantic Wind Connection, a proposed HVDC offshore transmission backbone from the Carolinas to New York and New England.

"Calculations provided to me as chairman of FERC at the time by the project developers indicated that the project was 'profitable' simply with energy interchanges between the Southeast and New York and New England," Wellinghoff said. "Although initial development costs were backed by Google and Japanese investors, the project was unable to secure funding to proceed with building actual transmission infrastructure."

Seiler also discussed challenges to the merchant model, noting that a radial merchant line that extends the PJM grid without connecting to another RTO or an identified generation project is not eligible to receive interconnection rights under PJM's Tariff. (See *FERC Rules Against Anbaric in OSW Tx Order*.)

He said the RTO and its stakeholders have discussed alternative approaches but have not reached consensus. He said the issue was the generation not being connected at the time of the request for the merchant transmission line. "The concerns at that time were really the locking up of the transmission capability for the offshore wind, when there may be competing needs with onshore generation at the time, and stakeholders could not come to any agreement in that space."

Silverman also expressed doubts about current rules, saying New Jersey's phased procurements make it impossible to "'broadly solicit interest in the project from potential customers or conduct a meaningful open season" as required by FERC's 2013 policy statement on merchant and participant-funded transmission. He said FERC should consider a "hybrid merchant" investment model that includes merchant features such as absorbing cost overruns and building facilities on a fixed-fee basis.

Lead Line vs. Network

Wellinghoff endorsed Brattle's proposed planned mesh network (PMN), saying it is "clearly superior in every single respect to the" radial, generator lead line model.

The PMN would be an HVDC backbone network that gathers power for multiple wind projects. Brattle proposed one each for ISO-NE and NYISO. Although Brattle did not do a study for PJM, "a unified single network could be created along the entire Eastern Seaboard from ISO-NE through PJM," Wellinghoff said.

He also called on FERC to issue a policy statement declaring PMN as the "preferred" OSW transmission infrastructure and convening a joint process involving ISO-NE, NYISO and PJM to develop a transmission infrastructure needs assessment and procurement process resulting in solicitations approved by the grid operators' boards.

Wellinghoff told *RTO Insider* he disagrees with a recommendation by the Business Network for Offshore Wind that the Department of Energy provide technical research and support for stakeholder engagement. (See *OSW Group Seeks Changes on Tx Planning, Cost Allocation*.) "FERC is the agency to do this job," he said.

Larry Gasteiger, former FERC chief of staff and now executive director of the trade group WIRES, agreed with the need for "a holistic planning process" to ensure cost-effective transmission development and said some of his members are eager to pursue OSW transmission projects. "But we also have members who … are in the middle of the country and have real concerns about being allocated costs for projects from which they're not seeing benefits," he said. ■

FERC/Federal News

OSW Advocates Look to CREZ, Tehachapi Examples

Solving the 'Chicken-and-egg Problem'

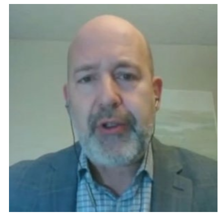
By Jason York, Michael Kuser and Rich Heidorn Jr.

Speakers at FERC's technical conference on offshore wind transmission Oct. 27 repeatedly invoked CAISO's Tehachapi Wind Resource Area and Texas' Competitive Renewable Energy Zones (CREZ) as models for developing the infrastructure needed to deliver remote wind to load centers. But they also acknowledged that both of those projects were limited to single-state grid operators, which simplified political and cost allocation issues.

While no one was willing to predict PJM's 13-state footprint or ISO-NE's six states would be able to replicate Texas' and California's successes, they said there are lessons to be gleaned, nonetheless.

Abe Silverman, general counsel for the New Jersey Board of Public Utilities, cited CREZ and Tehachapi as examples of the "bold vision" he said is needed for New Jersey and other East Coast states to meet their targets of almost 19 GW of OSW by 2035.

The Brattle Group's Johannes Pfeifenberger cited CREZ and Tehachapi as a counter example to ISO-NE's inability to capitalize on Maine's strong onshore wind.



Johannes Pfeifenberger, The Brattle Group | *FERC*

"Northern Maine has thousands of megawatts of low-cost onshore wind, and none of it is getting developed under the generator interconnection process because the transmission solutions necessary to interconnect that wind is too large for individual generators to pay for," he said. "The solution to that is regional planning."

Former FERC Chairman Jon Wellinghoff, now a consultant, said CREZ and Tehachapi are evidence that Brattle's proposed planned mesh network (PMN) is superior to the generator lead line model. "Both projects had multiple wind developers who agreed and understood that the PMN transmission infrastructure would be built and was the most cost-effective way to get their wind energy to market," he said. (See related story, *FERC Pushed to Change Tx Rules for OSW*.)

Tehachapi Wind Resource Area | *Southern California Edison*

Tehachapi

In a white paper released Oct. 26, the Business Network for Offshore Wind cited Tehachapi as a model for solving the "chicken-and-egg problem associated with the risk of building transmission to serve OSW generation." (See *OSW Group Seeks Changes on Tx Planning, Cost Allocation*.)

Located near Los Angeles, Tehachapi is the largest of the six wind resource areas in California, responsible for 3,282 MW of the state's 5,644 MW of operational wind capacity in 2016, *according to* the state Energy Commission. Although the project was a trunkline designed mostly to carry wind power, it also serves solar and storage and has multiple interconnections to the CAISO grid, allowing it to address local transmission congestion and reliability concerns.

In 2007, FERC *approved* CAISO's proposal to broadly allocate the initial cost of the trunkline to ratepayers, with generators later paying back some of the cost and ratepayers absorbing the risk of under-subscription. FERC required that the project serve remote generation, be designated by the state as serving an

FERC/Federal News

important "energy resource area," meet a minimum threshold of interest from interconnecting generators and be approved by the ISO's planning process. "An offshore transmission project should be able to meet those criteria," the Business Network said.

The project, 250 circuit miles, cost about $2.1 billion. Segments 1 to 3A were completed in 2009. Segments 4 to 11 were completed in late 2016, increasing the project's capacity to 4,500 MW.

CREZ

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

Former ERCOT Independent Market Monitor Beth Garza, now a senior fellow on electricity policy for R Street Institute, gave a detailed description of the development of CREZ. She noted that ERCOT has charged all load for all transmission since the wholesale generation market was opened to competition in the mid-1990s.

"One of the foundations that I believe led to the process being a success was a well established and well understood transmission cost allocation mechanism," she said. "The arguments over the allocation of costs were simply not an issue during the development of the CREZ plan."

Garza said the Texas Legislature authorized the project when it expanded its renewable portfolio standard because of frequent curtailments for the state's first wave of wind generation.

The legislation required the delivery of renewable energy from CREZ in a manner "most beneficial and cost effective to customers." In considering certificates of convenience and necessity for transmission lines, the bill did not require the Public Utility Commission to consider adequacy of the existing grid or the need for additional service. "This was the key aspect allowing a future-looking, enabling transmission plan to be developed," Garza said.

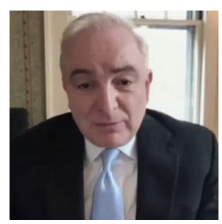
She also noted that the legislation did not define where the zones were or how much energy should be enabled, leaving that for the commission and stakeholders to decide. The commission ended up with five zones in West Texas and selected a target of 18.5 GW from among four potential scenarios ranging from 12 to 24.4 GW.

In 2009, the commission used a competitive process to select more than a dozen entities, including incumbent utilities and newly created transmission providers, to build the transmission under cost-of-service rates of return.

Generators had to make deposits of $10,000 to $15,000/MW to demonstrate their financial commitment. "During the five-, six-, seven-year process of actually defining the plan … wind generation developers could see, 'This is happening.' And more and more wind developers came into the queue," Garza said. "One of the phrases that we use frequently as a prelude to CREZ [was], 'If you build it, they will come,'" in reference to the film "Field of Dreams."

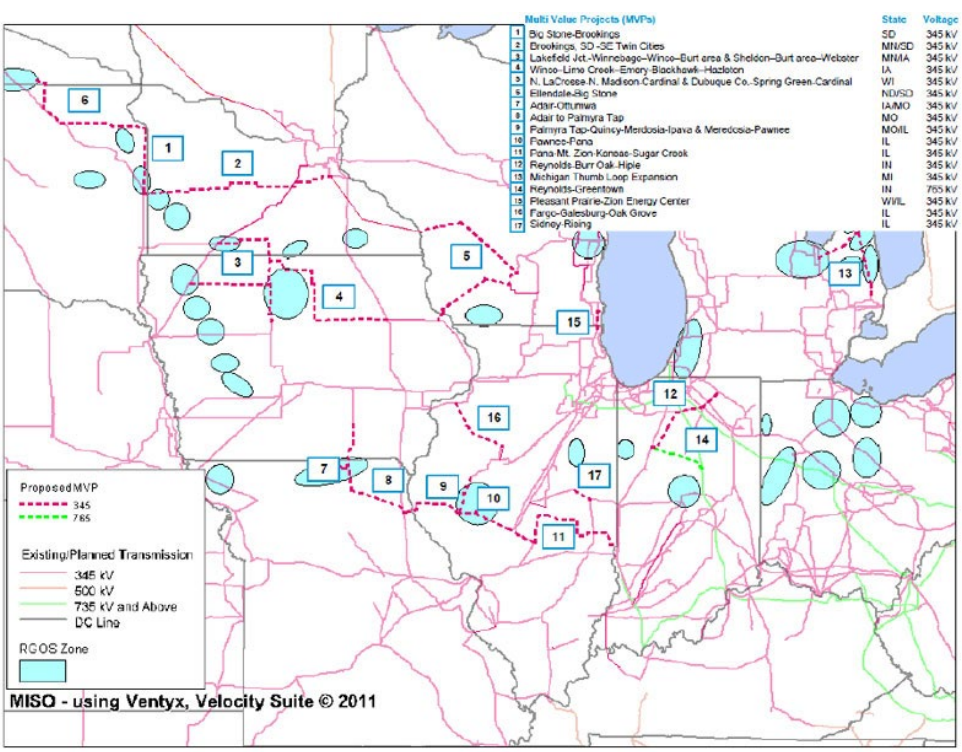
By early 2014, 3,600 circuit miles of transmission had been constructed. "The resulting plan enabled an almost tripling of wind capacity and energy at a time when wind was providing about 3% of [the state's] total generation requirement," Garza said. Although the project cost $6.9 billion, it also reduced electricity costs by $1.7 billion annually, *according* to Brattle.

Garza noted that two of the five CREZ zones are in the Texas Panhandle, which is part of SPP, not ERCOT. "I see that it's very similar to what my friends and colleagues on the East Coast are trying to do and unlocking this vast resource off the coast," she said.



Theodore Paradise, Anbaric | *FERC*

Texas now has more than 30 GW of wind, more than all countries except four, *according* to the American Wind Energy Association. "Certainly, a fair bit of that is because CREZ was put in," said Theodore Paradise, senior vice president for transmission strategy for Anbaric Development Partners.



MISO's Multi-Value Projects | *MISO*

Multi-Value Projects

While Tehachapi and CREZ were built by single-state grid operators, several speakers also noted MISO's success in winning approval of its Multi-Value Projects.

MVPs allowed MISO to finance $5.2 billion in transmission upgrades in 10 states through its centralized transmission planning process after its interconnection queue was swamped by requests from wind projects. It began with a plan to minimize total transmission and generation costs by accessing lower-cost wind resources.

"One of MISO's most important innovations was simultaneously accounting for … the value of transmission for meeting economics, reliability and public policy (renewable inter-

FERC/Federal News

connection to meet state RPS requirements) needs," the Business Network said. "MISO made sure to spread planned transmission projects across the entire MISO footprint to ensure that all zones received projects and had a strong benefit-to-cost ratio, ensuring their support for the overall portfolio. All Multi-Value Projects planned through this process received broad cost allocation to all MISO ratepayers."

Differences

FERC Commissioner Richard Glick asked the third panel of the technical conference whether there were aspects of OSW that were clearly not applicable to the CREZ and Tehachapi examples.

Eric Wilkinson, Ørsted | *FERC*

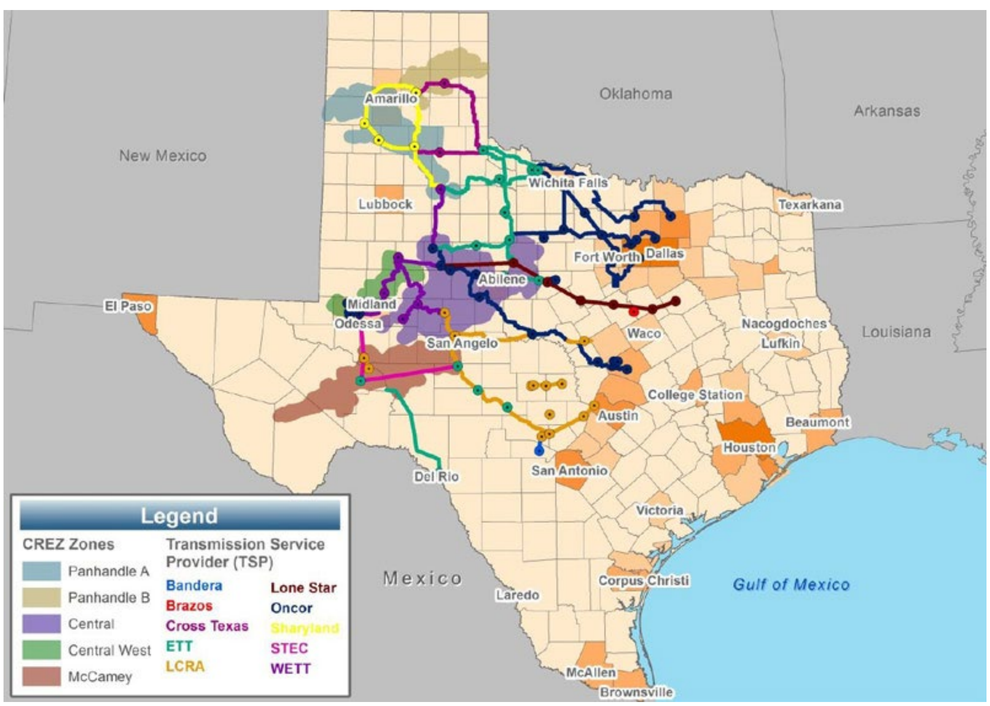
Eric Wilkinson, energy policy analyst for North America at Ørsted, said the risk allocation should be different from onshore because upgrades and outages at sea tend to take much longer than onshore. "Having those things more clearly locked up and defined before a shared system like that gets up and running is going to be critical," Wilkinson said.

Silverman agreed, saying, "I don't necessarily think it's a FERC role, but there is a huge difference in the risk. When you have a misalignment of onshore generation and transmission ... when you translate that to the offshore side, we're talking about such a huge amount of money being invested, and the losses can add up very quickly, so you really need to hammer home on this allocation of commercial risk."

Paradise said one of the big lessons learned from CREZ, Tehachapi and Europe's OSW development is that "the barriers we encounter are much more a case of what sentences are in tariffs, what words are on pages ... than physics problems. The second thing is we see that transmission is the great enabler. In Europe, we now see subsidy-free solicitations for offshore wind because the transmission is there and has made it competitive on the actual cost of energy."

Al McBride, ISO-NE | *FERC*

Al McBride, ISO-NE director of transmission services and resource qualification, said New England has two key takeaways from Tehachapi. "One was the technical piece, which is identifying the solution," he said. "But the more difficult part is cost allocation. ... I think what we're hearing ... from the states is certainly interest in what would our Tehachapi be, and which should we build?"



Texas' five Competitive Renewable Energy Zones and the transmission delivering wind power to load centers | *ERCOT*

"I don't necessarily think it's a FERC role, but there is a huge difference in the risk. When you have a misalignment of onshore generation and transmission ... when you translate that to the offshore side, we're talking about such a huge amount of money being invested, and the losses can add up very quickly, so you really need to hammer home on this allocation of commercial risk."

—Abe Silverman, general counsel for the New Jersey Board of Public Utilities

In a separate panel, Anne Marie McShea of Ocean Winds North America, cited CREZ to identify the keys to a successful "transmission first" model. But she said the East Coast would need to compress CREZ's "very long planning horizon."

"The overall time frame from legislation through to commissioning took nine years," she said. "A nine-year planning and construction horizon would push an operational offshore wind transmission backbone to 2030. This planning horizon would likely need to be compressed and then carefully managed in order to align with the next round of states' offshore wind solicitations."

The BPU's Silverman also cited CREZ as evidence of the need for cost controls, saying its cost ran to *$6.9 billion*, well above the original $4.7 billion budget. Part of the increase resulted from the redrawing of power lines to minimize disruptions, which added more than 600 miles of lines to the more direct routes originally envisioned.

"There is clearly a role for competition to reduce costs and prevent transfer of risk onto captive consumers," Silverman said. ■

‘Macro Grid’ Study Promises Cost Savings, Emission Cuts

By Rich Heidorn Jr.

A “macro grid” that allowed transmission of cheap renewable energy throughout the Eastern Interconnection would produce $7.8 trillion in private investment, create 6 million jobs, cut carbon emissions and save consumers more than $100 billion, according to a *study* released Wednesday by clean energy advocates.

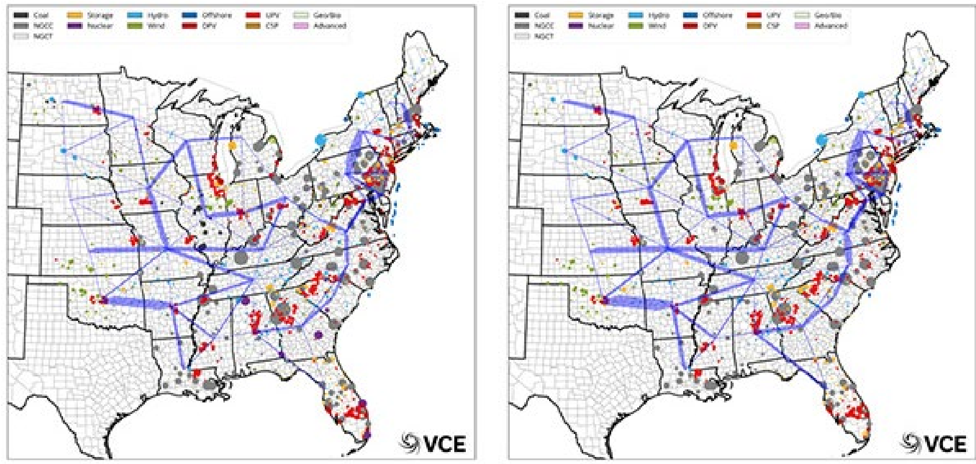
“Most of America’s world-class renewable resources are currently stranded in remote areas where the power grid is weak to nonexistent,” said the report by Americans for a Clean Energy Grid (ACEG), a coalition that includes the American Wind Energy Association, WIRES, transmission operator ITC Holdings and renewable generator Enel North America. “Policy barriers in how we plan, pay for and permit transmission are blocking private investment in modernizing our power grid.”

The report says its proposed transmission investments could “cost-effectively” cut electric sector CO_2 emissions by more than 95% by 2050, with the region getting more than 80% of its electricity from wind and solar.

It also claims average electric rates would drop by more than one-third, from more than 9 cents/kWh today to about 6 cents/kWh.

“Just as the Eisenhower interstate highway system unleashed U.S. manufacturing in the 20th century, a strong macro grid will deliver massive economic and public health benefits for all Americans in the 21st century,” ACEG Executive Director Rob Gramlich said.

The report does not identify the “policy barriers” nor recommend ways to overcome them. The authors said their focus was to illustrate the complementary roles that wind, solar, storage and transmission play in providing reliable and affordable power.



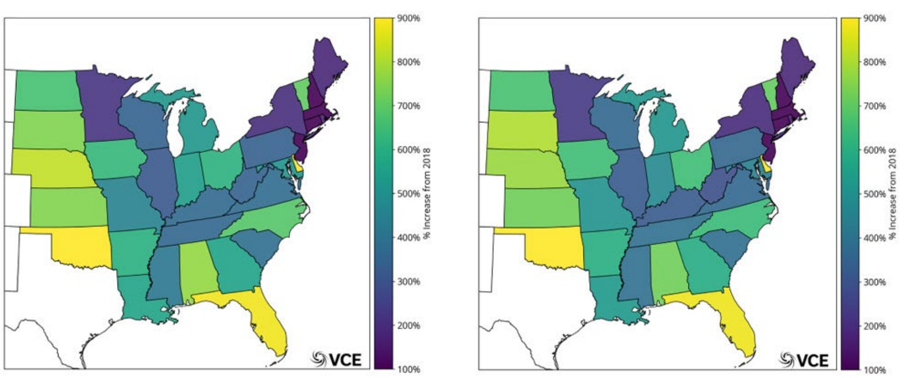
Transmission expansion (2030) under a strong carbon/high solar deployment (left) and strong carbon/high wind deployment | *Americans for a Clean Energy Grid*

4 Scenarios

The report includes four scenarios, including a “strong carbon reduction” case in which transmission costs would average 3.6% of total electricity costs. “Transmission yielded savings many times greater than that by providing access to low-cost renewable resources and increasing the overall efficiency of the power system,” it said.

It projects a fivefold increase in electric sector employment, with more than 6 million net new jobs.

“This job creation is driven by as much as $7.8 trillion in generation and transmission investment across the eastern U.S. through the year 2050,” it said. “Several states receive more than $400 billion in additional investment in generation and transmission, driving up tax revenue, indirect job creation outside of the electric sector and broader economic development. The vast majority of this investment will flow to economically depressed rural areas.”



Change in jobs (2018-2050) in the high solar case (left) and high wind case | *Americans for a Clean Energy Grid*

The report includes two “weak carbon policy” scenarios — one with high solar deployment and one with high wind deployment — created by extrapolating the “business as usual” rate of CO_2 emissions reductions from 2005 to 2017.

“Strong carbon policy” cases were based on meeting the Paris Agreement requirements.

The weak-carbon, high-solar scenario was estimated to require the addition of less than 80,000 GW-miles of interstate transmission by 2050 while the two strong carbon cases would add about 140,000 GW-miles. (A 500-mile transmission line that carried 2 GW would equal 1,000 GW-miles.)

“Many of the same transmission upgrades were built across all four scenarios, indicating these investments will be needed regardless of future trends in renewable costs or carbon reductions. The model also used battery storage to increase the utilization of transmission lines, demonstrating that storage is a transmission complement, not a substitute,” it said. “Storage, particularly storage that is strategically sited near wind and solar resource areas, can complement transmission investment by increasing the utilization factor of transmission lines.”

The high-solar scenario deploys much of the storage in the East, particularly the Southeast, to shift excess daytime production to the night.

The high-wind scenario would put much of the storage in western states such as Kansas and South Dakota. “Notably, much of that storage shifted out of Indiana and Pennsylvania, where expanded west-east transmission delivering wind generation to the Northeast steps in to replace the need for storage,” the report says. ■

FERC/Federal News

Overheard at WIRES Fall Member Meeting 2020

The U.S. transmission system will require significant restructuring and greater alignment with public policy goals to meet the future needs of the electricity sector, according to industry insiders speaking at WIRES' virtual fall member meeting last week.

The trade group promotes investment in transmission and progressive government policies to advance energy markets, economic efficiency, and consumer and environmental benefits through electric infrastructure development.

Here is some of what *RTO Insider* heard at the event.

Clockwise from top left to right: Joseph Kelliher, former FERC chairman; Rob Gramlich, Grid Strategies; Jasmin Melvin, S&P Global Platts; and Antoine Lucas, SPP | *WIRES*

Logjams, Dysfunction

During a panel on the integration of renewable energy and its impact on transmission, former FERC Chairman Joseph Kelliher said if he were an all-powerful king or wizard with a magic wand, he would change the structure of transmission ownership in the U.S.

"When I was at FERC, I was really stunned when National Grid testified at a FERC conference saying that the U.S. had at the time 492 different owners of the grid, and the government owns a third of the grid," Kelliher said. "I think it would work better if you had a series of regional, national grids, something along the lines of our U.S. pipeline network. Pipelines are all corporate structured. They're separated from production, dedicated completely to the business of moving other people's gas. If you had regional, national grids whose only businesses were transmitting other people's electricity, I think they'd be much more focused on quickly investing and anticipating the needs of the market."

Kelliher added that the more realistic option is "effective, proactive regional transmission planning and execution of those plans."

Grid Strategies President Rob Gramlich concurred and added that he does "a lot of work with renewable energy companies and associations, and what they see and feel right now is a symptom of a bigger disease."

"What they see is interconnection queue logjams and dysfunction where you get to a certain number of projects in the queue, and suddenly the costs balloon, and then they jump out, and everybody else has to be restarted. It's a total mess," Gramlich said.

He said the interconnection queue problems could be "alleviated" by aligning transmission planning — and the cost allocation associated with it — with utility and state public policy goals.

Antoine Lucas, vice president of engineering for SPP, said he advocates for improved or increased alignment between the transmission planning processes and cost allocation.

"Any efforts that can create more alignment in that area, create more of a clear vision, will remove a lot of the hurdles that we see plague some of the transmission planning processes, including the generator interconnection process that Rob mentioned," Lucas said. "We do have a lot of entities who are all working hard to try and serve the needs of their members or customers, but when you have so many different plans, different strategies, optimizing those is a significant challenge that if we could bring more alignment to it, I think we'd be able to see more get done at the national level."

Kelliher said regional grid development currently relies "very heavily on network upgrades funded by generators," which "is an inefficient way to build out the grid."

"If you rely less on network upgrades and have more proactive regional planning, you have more clear cost allocation that's as regional as possible," Kelliher said. "You probably need to abandon the competitive provisions of [FERC] Order 1000, which I don't take lightly. But I think the reason you have utilities deferring, going to great lengths to avoid regional cost allocation, is they don't want competition for their projects."

Gramlich said he would like to see much more hands-on leadership from FERC, "not just serving as sort of judges." He cited current Commissioner Richard Glick and former Commissioner Cheryl LaFleur, now on the Board of Directors for *ISO-NE*, as positive examples of FERC working with governors and stakeholders on the interregional planning process.

Gramlich added there are "30 GW of offshore wind in the goals across the Northeast states [and] that it's going to be much more efficient to proactively build transmission if those states get together and say, 'OK, here's what we'd like our RTOs and ISOs to do to proactively plan this.' So, I think it will require both state and federal leadership outside of just the stakeholder processes."

From the RTO perspective, interregional projects have two main challenges, Lucas said: cost allocation and siting. He said siting "seems to be an issue that creates a tremendous amount of friction, specifically when you're talking

FERC/Federal News

about state authority versus federal authority."

"I think any clarity on that would go a long way in helping to solve the problem, but I do recognize it's a very challenging issue," Lucas said. "If it were to be taken up again at FERC, I don't know how successful it might be."

'No Silver Bullet' for Energy Transition

In his keynote speech, Sen. Joe Manchin (D-W.Va.), ranking member on the Senate Energy and Natural Resources Committee, said the demand for clean energy is growing to address climate change. The challenge, however, is "maintaining affordable, reliable and dependable energy while also reducing emissions, and ensuring that hardworking families and communities that have powered our nation to greatness aren't left behind in the transition."

"There's no silver bullet. We're going to need a variety of solutions to ensure we can meet this challenge both at home and around the world, where fossil fuels are going to be used for decades to come," Manchin said. "That's why I say we need innovation, not elimination."

Manchin said that his and Sen. Lisa Murkowski's (R-Alaska) *American Energy Innovation Act* would invest $24 billion to advance critical technologies such as renewable energy, advanced nuclear, cybersecurity, energy storage, grid modernization, and carbon capture, removal, utilization and sequestration. It would also push technologies that can reduce emissions in four sectors of the economy that currently contribute about 90% of the nation's overall greenhouse gas emissions.

"These varied solutions are necessary for us to reach any goal for reducing greenhouse gas emissions," said Manchin, who hopes the bill comes to a vote during the lame-duck session following the elections. "They would also strengthen the United States' position as an exporter of the technologies other countries will also need to tackle this global climate problem."

Manchin added that the energy mix is changing with more renewables coming online and the retirements of older fossil-fuel units. That means "cost-effective energy storage is a critical technology to advance, and that's also why a more flexible and modern electric grid is needed," he said.

He said there is "a good argument for investment in grid infrastructure to help us meet our challenges."

Sen. Joe Manchin (D-W.Va.) | *Wires*

"We know that transmission is an essential component of a reliable and resilient grid because we know what happens when congestion disrupts the system," Manchin said. "I expect transmission to get a good deal of attention next year. I know several bills seek to advance transmission by improving the interregional planning process at FERC or extending the investment tax credit to transmission."

Manchin added that he hoped the "two very qualified nominees" for FERC — Allison Clements and Mark Christie — can be confirmed during the lame-duck session. (See *FERC Nominees Bob and Weave Through Senate Hearing*.) Clements, a Democrat and energy policy adviser for the Energy Foundation, and Christie, a Republican and chair of the Virginia State Corporation Commission, were nominated by President Trump in late July. Clements would fill the seat left open by the departure of LaFleur in August 2019. Christie would take the place of Bernard McNamee, who departed in September.

"I think we can all agree that the best FERC is a fully seated FERC," Manchin said. ■

— Jason York

CAISO/West News

SoCal Edison Line May Have Started Silverado Fire

Utility Now Under Scrutiny in 2 Major Wildland Blazes

By Hudson Sangree

Southern California Edison told the state Public Utilities Commission that one of its power lines might have started the Silverado Fire, an explosive blaze that critically injured two firefighters and caused tens of thousands of residents to flee their homes last week.

"It appears that a lashing wire that was attached to an underbuilt telecommunication line may have contact[ed] SCE's overhead primary conductor, which may have resulted in the ignition of the fire," SCE told the CPUC in an incident *report* Oct. 26. On a transmission tower or pole, an "underbuilt" line is one strung under electric power lines in a space reserved for telecommunication infrastructure.

"Preliminary information reflects SCE overhead electrical facilities are located in the origin area of the Silverado Fire," the utility said. "We have no indication of any circuit activity prior to the report time of the fire, nor downed overhead primary conductors in the origin area."

The 13,350-acre fire, which ignited and spread quickly during powerful Santa Ana winds on Oct. 26, was 25% contained as of Wednesday afternoon, according to the California Department of Forestry and Fire Protection. It threatened thousands of structures northeast of the densely populated city of Irvine in Orange County.

Another blaze, the 14,334-acre Blue Ridge Fire, also started in the hills of Orange County on Oct. 26. Firefighters brought it under control Wednesday as winds subsided and many residents in both fire areas were allowed to return to their homes.

2nd Incident

SCE's report to the CPUC marks the second time this fire season that the state's second largest utility has fallen under suspicion for starting a major wildfire.

In September, SCE filed a report with the CPUC saying the Bobcat Fire, burning in the mountains near Los Angeles, started in the same area and around the same time as the utility experienced a line fault. However, SCE said a fire camera had recorded smoke from the blaze shortly before its relay tripped, suggesting the fire preceded the line problem.

A jet drops fire retardant on the Silverado Fire near Irvine, Calif. | *Orange County Fire Authority*

"The Bobcat Fire was reported in the vicinity of Cogswell Reservoir/Dam in the Angeles National Forest on Sunday, Sept. 6, 2020, at 12:21 p.m.," SCE told the CPUC. "The Jarvis 12-kV circuit out of Dalton Substation experienced a relay operation at 12:16 p.m. on Sept. 6, 2020. The Mount Wilson East camera captured the initial stages of the fire, with the first observed smoke as early as approximately 12:10 p.m., prior to the relay operation."

Both fires remain under investigation. The investigation of the Bobcat Fire is being conducted by the U.S. Forest Service, which on Sept. 15 "requested that SCE remove a specific section of SCE overhead conductor in the vicinity of Cogswell Dam," the utility reported. (See *Calif. IOUs Escape Blame for Fires So Far*.)

SCE and Pacific Gas and Electric have been trying to avoid starting wildfires this season after three years of cataclysmic blazes in 2017-2019 that hammered the companies' finances.

PG&E, which entered bankruptcy in January 2019 because of an estimated $30 billion in wildfire liabilities, has turned off power to hundreds of thousands of residents on multiple occasions this summer and fall in public safety power shutoffs (PSPS) meant to prevent utility equipment from sparking fires.

Nevertheless, a PG&E distribution line fell under scrutiny in the Zogg Fire, which killed four residents in a rural area near Redding, Calif. (See related story, *PG&E Line Was Active when Zogg Fire Started*.)

After emerging from bankruptcy in June, PG&E's stock price, which exceeded $70/share before its equipment started the wine country fires of October 2017, has generally hovered around $9 to $10/share. It stood at $9.70/share at close of trading Wednesday.

SCE has been more conservative in its power shutoffs, partly because it lacks the PG&E's vast territory in fire-prone areas and has had longer experience using PSPS.

As news spread of SCE's possible involvement in the Silverado Fire spread, the already lagging stock price of its parent company Edison International fell further on Wednesday, from a high of $58.64/share at 10 a.m. ET to $56.56/share at the close of trading. ■

CAISO/West News

PG&E Line Was Active when Zogg Fire Started

By Hudson Sangree

Pacific Gas and Electric last week told the federal judge overseeing its felony probation that a distribution line under investigation for starting the deadly Zogg Fire on Sept. 27 remained active even as other circuits in the same region were de-energized during a large-scale public-safety power shutoff.

In a court filing Oct. 26, PG&E responded to an inquiry by U.S. District Court Judge William Alsup about the utility's possible role in starting the Zogg Fire in Shasta and Tehama counties. The fire killed four people, including a mother and her 8-year-old daughter, destroyed 204 structures and burned more than 56,000 acres before being brought under control.

The California Department of Forestry and Fire Protection (Cal Fire) seized a portion of PG&E's 12-kV Girvan 1101 circuit near the rural community of Igo, where the fire began, PG&E told the California Public Utilities Commission in an Oct. 9 incident report. (See *PG&E Under Scrutiny in Deadly Zogg Fire*.)

Alsup asked PG&E to explain why the Girvan circuit hadn't been de-energized, and who made that decision, during the Sept. 27-29 public safety power shutoffs (PSPS) that blacked out more than 64,000 customers in 15 counties in Northern California.

"The Girvan circuit was energized because PG&E's PSPS models, developed well before the Zogg Fire, did not identify that circuit for potential de-energization based on the facts and weather predictions available for the Sept. 27, 2020, PSPS event," the utility told Alsup.

"Circuits not identified for inclusion in the scope of a potential PSPS event remain energized and are not subject to any decision during the event to leave the circuit energized," PG&E said. "Accordingly, there was no 'decision to leave [the line] energized.'"

The utility said it experienced a series of drops in voltage on the Girvan circuit on the afternoon the Zogg Fire started. But the problems weren't enough to cause a line "recloser to open or 'trip,' resulting in de-energization of the line it protects," prior to the fire's start.

The line de-energized only after a wildfire camera and satellites photographed smoke, apparently from the fire, the utility said.

PG&E told Alsup it did not yet know if its equipment started the fire.

"PG&E recognizes the devastation caused by the Zogg Fire, which resulted in the loss of four lives and destroyed many homes," it said. "Like the court, PG&E is actively seeking to understand the cause of the fire and the role, if any, of PG&E's facilities."

Alsup has been an outspoken PG&E critic during his years overseeing the utility's probation on felony convictions related to the San Bruno gas pipeline explosion in September 2010.

PG&E noted in its filing that during the five days Alsup gave it to respond to his Oct. 21 order, it had been engaged in a massive PSPS event stemming from the driest and windiest conditions of the year and that "relevant PG&E personnel who may have otherwise provided input" were unavailable.

The utility shut off power to 361,000 customers, or more than 1 million residents, in portions of 36 counties on Oct. 25 and 26 as powerful Diablo winds swept through the Sierra Nevada foothills and the coastal mountains north of San Francisco, where its equipment started major fires in 2017, 2018 and 2019.

During last week's wind events, numerous small fires started in Northern California but were largely under control as of Oct. 27, Cal Fire reported. Santa Ana winds rapidly spread two major fires in Southern California, the Silverado and Blue Ridge, the causes of which remain under investigation. ■

A PG&E power line is under scrutiny for starting the Zogg Fire on Sept. 27. | *Jeff Head via Flickr*

PG&E Trying to Move Forward from Bankruptcy

Attempts to Reassure Investors with Fire Prevention Efforts, Customer Service

By Hudson Sangree

In a third-quarter earnings call Thursday, PG&E Corp. executives tried to reassure investors that the company is on track to move forward from its bankruptcy, the catastrophic wildfires of the last three years and the botched power shutoffs that blacked out more than 2 million residents in 2019.

PG&E emerged from bankruptcy in June after a settlement with fire victims that gave them a 22% equity stake in the state's largest utility.

"With a full quarter behind us after the bankruptcy, we're now very focused on executing well on the operational and financial plan we set out," interim CFO Chris Foster said. "We have a strong earnings projection ahead of us supported by regulatory outcomes … and we are excited about the long-term opportunities provided by our state's focus on clean energy technology."

PG&E recorded GAAP earnings of 4 cents/share for the third quarter, compared to losses of $3.06/share for the same period in 2019. Non-GAAP core earnings were 22 cents/share compared to $1.11/share.

In the second quarter, PG&E reported GAAP losses of $3.73/share, driven mainly by $2.5 billion in costs to exit bankruptcy and help pay for the 2019 Kincade Fire. (See *PG&E Reports Steep Q2 Loss on Bankruptcy, Fire Costs*.)

On Thursday, PG&E said it had upped its estimates for the costs of the Kincade Fire, an October 2019 blaze not covered by bankruptcy settlements, to $170 million. The cause remains under investigation by the California Department of Forestry and Fire Protection (Cal Fire), though early indications were that the fire started beneath a PG&E transmission line running from a geothermal plant north of the Napa and Sonoma valleys.

PG&E said it had not de-energized the line because the weather conditions at the time did not meet the criteria in its public safety power shutoff (PSPS) protocols.

Analysts on Thursday's call also asked about the Zogg Fire, a deadly blaze near Redding that started in late September. Cal Fire seized a portion of a PG&E distribution line in its ongoing investigation of the wildfire. PG&E said Thursday that line had also remained energized because of a relatively low wind speed forecast at the time. (See *PG&E Line Was Active when Zogg Fire Started*.)

The 2019 and 2020 fires hang over PG&E's head, along with memories of last year's PSPS events that drew severe criticism from the public and elected officials.

In fall 2019, PG&E blacked out 2.4 million residents, often without sufficient warning and without providing information about when power might be restored. The company's websites crashed under a heavy surge, requiring emergency intervention by state agencies. (See *California Officials Hammer PG&E over Power Shutoffs*.)

This year PG&E promised "smaller, shorter and smarter" shutoffs, with ample public notice and quicker restoration. It gave at least 48 hours' notice of possible blackouts, and it moved its websites from its data center to the cloud, with testing to make sure the servers could handle heavy traffic, interim CEO Bill Smith said in the call with investors.

The company also set a goal of reducing the number of customers impacted by one-third from last year and met that mark in the five PSPS events it has instituted this year, Smith said. In its latest PSPS event on Oct. 25 and 26, PG&E blacked out 345,000 customers in portions of 34 counties but restored power to almost all by Wednesday.

Another criticism from last year was that PG&E had not set up a sufficient number of community centers where those who lost power could receive aid. Smith said this year PG&E made 50 centers available to 172,000 residents versus 80 centers for 1 million residents last year.

Despite the utility's reported efforts, its lagging stock price didn't move much Thursday. It opened trading at $9.64/share and closed at $9.75/share. PG&E stock was worth more than $70/share before its equipment started the wine country fires of October 2017. ■

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CAISO/West News

Study: Western RTO Could Yield $1.2B in Yearly Savings

By Robert Mullin

The creation of a single RTO covering the entire U.S. portion of the Western Interconnection could save the region more than $1.2 billion annually in electricity costs, according to the findings of a state-led study funded by the U.S. Department of Energy.

The *study*, an ongoing two-year effort, was initiated by the Utah Governor's Office of Energy Development in partnership with state energy offices in Colorado, Idaho and Montana.

"The project is unique in that it provides Western states with a neutral forum and neutral analysis to independently and jointly evaluate the options and impacts associated with various market options in the West," Brooke Tucker, deputy director of the Utah energy office, said Friday during a virtual meeting of the Committee on Regional Electric Power Cooperation and the Western Interconnection Regional Advisory Board (CREPC-WIRAB).

The study attempts to identify state-by-state savings in capacity and adjusted production costs (the net cost to serve load) under various market scenarios, including a full RTO for the West.

"From a load diversity standpoint, nobody loses" from membership in a West-wide RTO, Keegan Moyer, principal with study author Energy Strategies, said in presenting the findings to CRECPC-WIRAB stakeholders. "There's some larger winners than others, and that's simply due to the nature of the system and the coincident or noncoincident nature of the peaks, but we really walked away with the observation that the entire West has a lot to gain from a load diversity standpoint."

The findings Moyer presented Friday focused on two different market constructs.

The first was the existing Western Energy Imbalance Market (EIM), with its centrally optimized real-time dispatch; separate balancing authority areas and transmission tariffs; limited transmission dedicated to market transfers; and continued operational control by transmission providers.

The second market construct was a full RTO, with consolidated BAAs and the transfer of transmission operations to a central operator; a centralized real-time and day-ahead market; joint transmission tariffs for all members within a given footprint; transmission available up to reliability limits; and joint transmission planning and cost-sharing.

The study also looked at the impacts of a third construct — the EIM with the inclusion of a day-ahead market — but that option didn't figure heavily into Moyer's presentation. "The day-ahead market really is an expansion on a real-time-only market, where we're simply introducing a day-ahead optimization time frame into this market, whereas pretty much everything else remains the same. The big shift comes with the RTO framework," he said.

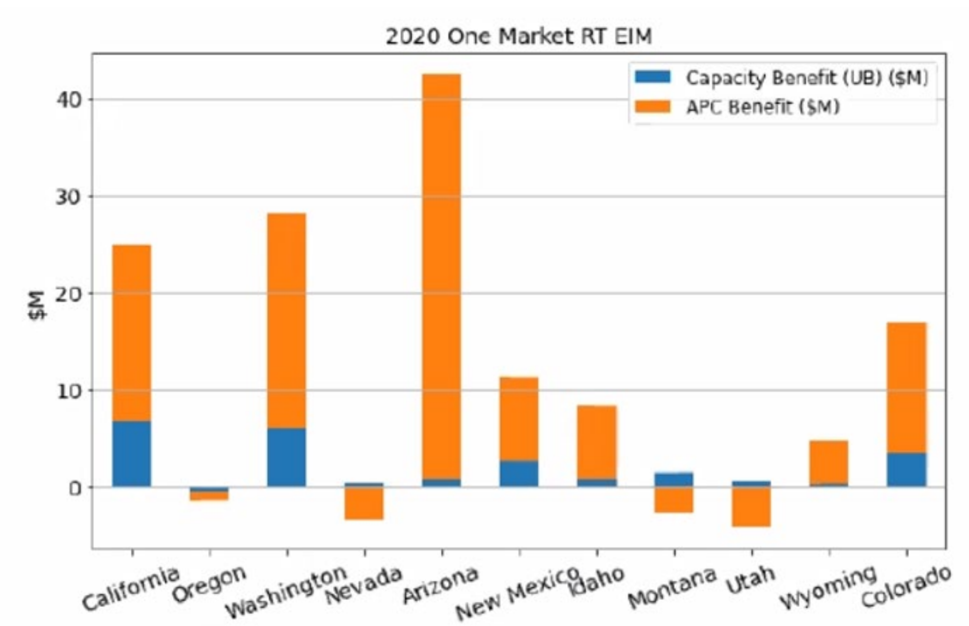
The study authors then overlaid the market constructs over two different footprints to evaluate potential "market configurations":

- a "status quo" scenario consisting of an EIM that includes both existing members and those entities that had committed to joining the market by the end of 2019;
- a "one market" EIM expanded to include the entire U.S. footprint of the Western Interconnection; and
- a West-wide RTO covering the same footprint.

The analysis examines the market configurations from the perspective of both capacity and production cost savings based on 2020 resource portfolios. Moyer noted the analysis did not attempt to capture other potential benefits. "There are some efficiencies from competition that we're not really getting at," he said.

"The day-ahead market really is an expansion on a real-time-only market, where we're simply introducing a day-ahead optimization time frame into this market, whereas pretty much everything else remains the same. The big shift comes with the RTO framework."

—Keegan Moyer, principal with study author Energy Strategies



Arizona, Washington and California would gain the most from an expansion of the EIM into the entire U.S. portion of the Western Interconnection, according to the study. | *Energy Strategies*

CAISO/West News

Load Diversity is Key

Moyer explained that capacity benefits in the full RTO scenario flow from "load diversity" — the notion that different areas of the Western system peak at different times, "whether that be an hour or two apart or perhaps seasons apart."

"In the absence of any kind of coordination, we assume each balancing area will require sufficient capacity to meet its peak plus some amount above that, roughly commensurate with a reserve margin," he said. "However, the coincident peak demand for a combined footprint of those same balancing areas would typically be less than the sum of the individual peaks."

The overall reduction in peak load counted across the interconnection would allow load-serving entities in an RTO to build or contract for less capacity to meet resource adequacy requirements, the study assumes.

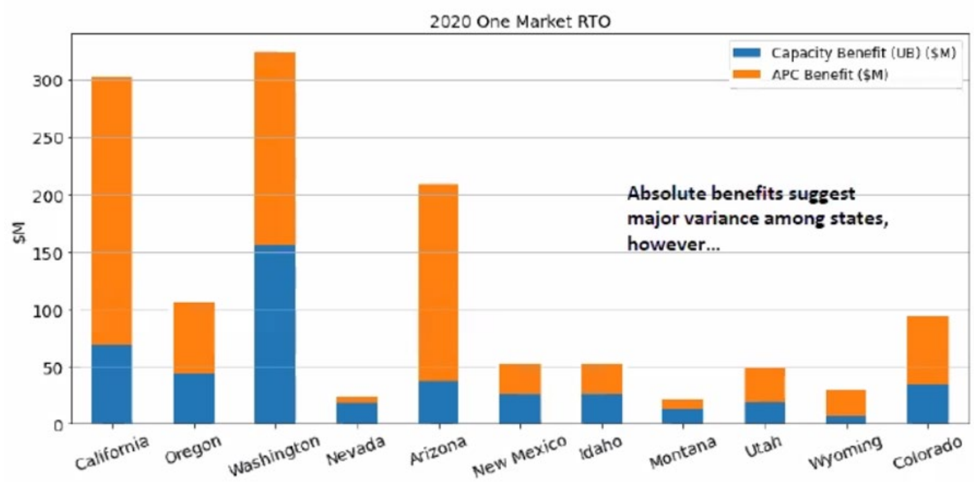
Those reduced needs add up. The study found that under the status quo, the region can expect to realize up to $25.2 million in annual capacity savings, while a "one market" EIM could yield up to $47.8 million in savings. An RTO boosts the potential capacity savings tenfold to up to $478 million.

But the biggest economic gains from an RTO flow from adjusted production cost (APC) savings, according to the study. Moyer called APC the "primary metric for determining state benefits" because it captures the benefits and costs of both net sales and purchases within an area, whereas a simple production cost figure can "mask some of the benefits" for high-export areas that ring up higher production costs that are also offset by sales into the market, reducing net costs to serve native load.

"It's important to consider this metric instead of others that we have available to us," Moyer said.

Based on that metric, an expanded EIM would yield about $105 million to $127 million in annual APC savings — on top of the existing EIM benefits of more than $300 million a year — compared with the status quo scenario. Arizona, Washington and California lead in absolute benefits under that scenario, while four states — Oregon, Nevada, Montana and Utah — actually lose out (see graphic, previous page).

By comparison, a full RTO would produce APC savings of $811 million, bringing the estimated total savings from an RTO to more than $1.2 billion (see graphic above). Washington would be the biggest winner at $324 million, followed by California ($303 million), Arizona ($209 million), Oregon ($106 million), Colorado ($95 million), Idaho ($53 million), New Mexico ($52 million) and Utah ($48 million). Fewer benefits would flow to Wyoming ($29 million), Nevada ($23 million) and Montana ($21 million).



Washington, California and Arizona stand to gain the most savings from a Western RTO, the study found. | *Energy Strategies*

Moyer attributed part of Washington's large benefit figure to an increased value of the Pacific Northwest hydroelectric system, "just from a simplified energy revenue standpoint."

He also pointed out that the state would shift from a winter to a summer peak under a consolidated RTO scenario, "so there's a savings really kind of embedded in that shift" because of the load diversity effect, he said. The study found that Washington would realize more than 4,000 MW in capacity savings from its load diversity relative to the rest of the footprint. Meanwhile, its summer-peaking neighbor to the south, Oregon, would see a capacity benefit of slightly more than 1,000 MW.

Adoption of either market configuration would result in only minor reductions in Western CO_2 emissions: 0.1% for the expanded EIM and 0.7% for the RTO. The study's findings also indicate only slight changes in the types of resources being dispatched under both configurations, at least based on current generation fleets.

"Overall, the big finding here is that, at least in 2020, we don't believe that market constructs or these incremental constructs that we're modeling cause major shifts between generation types," Moyer said. Instead of a major shift from coal to gas, the study finds shifts within each class of generator, with the most efficient being dispatched.

"And [in the RTO scenario], we're doing a little better job of integrating renewables, and on aggregate, those efficiencies are causing emissions to decrease somewhat, but not a significant amount," Moyer said. He added that renewable curtailments are low under either scenario but were "already low to begin with."

The study showed a shift in transmission flows, Moyer said, "but not significant enough to cause congestion."

By the States, for the States

"I think the state-specific results are really helpful," said Oregon Public Utility Commissioner Letha Tawney, who is also the chair of the EIM's Body of State Regulators (BOSR). "We often see results that are for a particular utility, or a particular balancing area, or across all of the WECC ... and we're left with making assumptions about what that means for our consumers in our states."

The state-by-state breakdown of benefits gives each state a "fact set" for approaching increased regionalization, with the states enjoying more obvious benefits being less concerned about the costs of joining an RTO.

"We all care about costs — don't get me wrong — but there's more room for a cost-effectiveness test if the benefits are clearly demonstrated in a single direction, where a state that's running a little closer to a cost-benefit analysis break-even point might be more conservative," Tawney said.

As chair of the BOSR, Tawney said, she seeks to identify a consensus view around CAISO processes, "and this sort of study that's so neutral and sort of lays out the state perspective ... is really enormously helpful in understanding how differently states are experiencing the

CAISO/West News

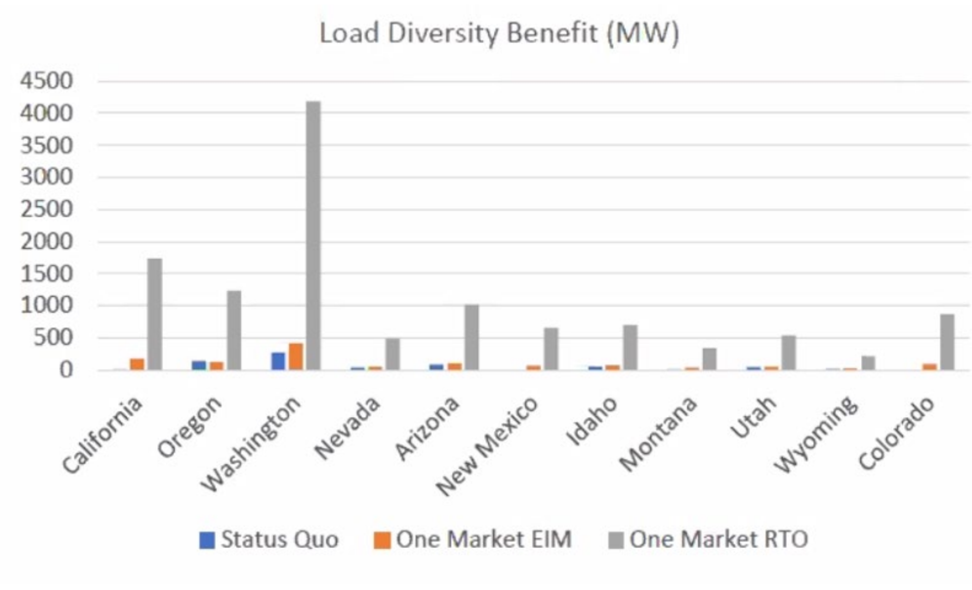
market today and what value their consumers can really find in it."

Tawney noted the study's finding that the market is not "inherently" changing the resource mix in the West.

"It's being driven, as far as the models demonstrate, far more by customer choices, and those customer choices might be demonstrated to the market through either voluntary commitments or through legislative actions or in-state carbon prices," she said.

Tawney said she looked forward to the findings of the next iteration of the study, which will examine 2030 projections that "layer in the customer choices that have been expressed."

"What I think this [study] clarifies is that the market makes reaching state clean energy goals more efficient, particularly less costly, rather than explicitly reshuffling the deck automatically," she said.



Washington would earn the greatest capacity benefit from membership in an RTO because of the fact that it would move from being a winter-peaking system to being a member of a summer-peaking system. | *Energy Strategies*

Keith Hay, director of utility policy for the Colorado Energy Office, said the study comes at an "interesting time" when his state is undergoing an energy transition and its public health authority is calling for an 80% reduction of carbon emissions below 1990 levels by 2030, compared with the current 70% goal.

"I think for us as a state, it's helpful that one of the outcomes of this work will be a set of factors that states might want to consider as they look at their market orientation," Hay said. He noted that previous discussions at the Colorado Public Utilities Commission about whether to join an organized market prompted questions about how to make the decision, given the different factors stakeholders asked the state to consider.

"I think it's important as this study comes forward, we'll learn a lot from the perspective of the state and the state commissions, so it's not being driven by a utility or a particular set of stakeholders who may have an interest in the outcome," Hay said. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Members Approve Measure on Private-use Networks

ERCOT stakeholders last week approved the oldest protocol change on the grid operator's books, shooting down a late request to table the measure in the process.

Luminant filed comments on the revision request the day before it would be considered by the Technical Advisory Committee and requested a delay so committee members could review the comments.

The Nodal Protocol revision request (*NPRR945*) is hardly controversial. It simply removes the "associated load" term that proponents say has been interpreted in some instances to restrict private-service arrangements otherwise authorized under state law and regulatory precedent.

"We filed the comments because we've heard from different groups that the NPRR didn't change anything," Luminant's Ian Haley said during the TAC's web meeting Wednesday. "We had concerns that TAC would be voting without understanding what it does. We wanted to ensure TAC is well aware of what we're voting on today."

Attorney Katie Coleman, representing Texas Industrial Energy Consumers and the measure's sponsor, accused Luminant of "a little bit of sandbagging," noting the revision dates back to May 2019 and that the company has had "ample opportunities to relay this concern."

She reminded members that the issue has been discussed several times within the TAC's Protocol Revision Subcommittee and that she conducted a workshop where she went through the NPRR's effects and its history.

"This section of the protocols was meant to define the electric configurations that were eligible for net metering. It does not pertain to legal and regulatory requirements," Coleman said. Referring to "associated load" as an "ambiguous term," she said, "That term has been interpreted as load and generation to be owned by the same entity.

"That's not what the language says, and I'm not sure it's clear to market participants. It's more restrictive than what the law allows in certain scenarios," Coleman said. "We have [private-network] sites set up today, lawfully set up, and some reviewed by the [Public Utility Commission] in contested cases, where load and generation is not owned by same entity."

Removing the term, Coleman said, will provide regulatory certainty for both existing and planned sites by deferring to legal and regulatory precedent and avoid potentially inconsistent interpretations of the protocols.

Katie Coleman, TIEC | © *RTO Insider*

The NPRR adds language that "explicitly state[s]" that private-service arrangements must comply with PUC precedent and Texas' Public Utility Regulatory Act. It also adds market transparency with a new reporting requirement that identifies all generation resources and settlement-only generators registered as part of behind-the-meter private-use networks (PUNs).

Luminant says NPRR945 provides clarity to those seeking to set up PUNs, but it raises "many additional and equally important policy questions, some of which cannot be addressed by ERCOT stakeholders."

The generation company said PUNs are neither typical loads nor typical generation resources and are subject to nonmarket incentives that "warrant appropriate controls" to ensure their usage "balances risk and reward fairly across market sectors and customer classes."

"In an energy-only market, this can actually harm resource adequacy objectives … by allowing a single entity to capture scarcity value that does not accrue to the rest of the market," the company said in its *comments*. "Luminant supports correct pricing outcomes that utilize the demand of consumers in ERCOT and all generation bids needed to meet that demand. Unfortunately, [PUNs] bypass this needed aspect of price formation."

"As Luminant is starting to understand, this has potential implications that are pretty serious," said Golden Spread Electric Cooperative's Michael Wise, saying he was concerned about cost shifts and their unintended consequences. "ERCOT's interpretation of the protocols and the term 'associated load' has protected consumers very well. We believe it's probably one of the most important issues brought forward to stakeholders and it merits this attention."

Other TAC members weren't so sure.

"With all due respect to Luminant and Golden Spread, these issues you're raising are issues we've been discussing for months and months," Demand Control's Shannon McClendon said. "Katie has given detailed information. PUNs do not cause additional costs to the consumer. That's a red herring Golden Spread is putting out there."

Reliant Energy Retail Services' Bill Barnes said that although he shared some of Luminant and Golden Spread's concerns, he was "cautiously supportive" of NPRR945.

"I don't think minds will change in one month. I don't see the need to table," he said.

The motion to table failed 8-22. The TAC then passed the measure by a 23-5 margin, with two members abstaining.

Staff, WMS to Address Market Delays

ERCOT staff will work with the TAC's Wholesale Market Subcommittee to address what has literally become a growing problem.

At issue are the increased complexities of the day-ahead market (DAM), which has led

ERCOT News

to a steady increase in the market's ability to publish its results on time. There have been 20 delays this year, the most since 42 in 2011, the first year of ERCOT's nodal market.

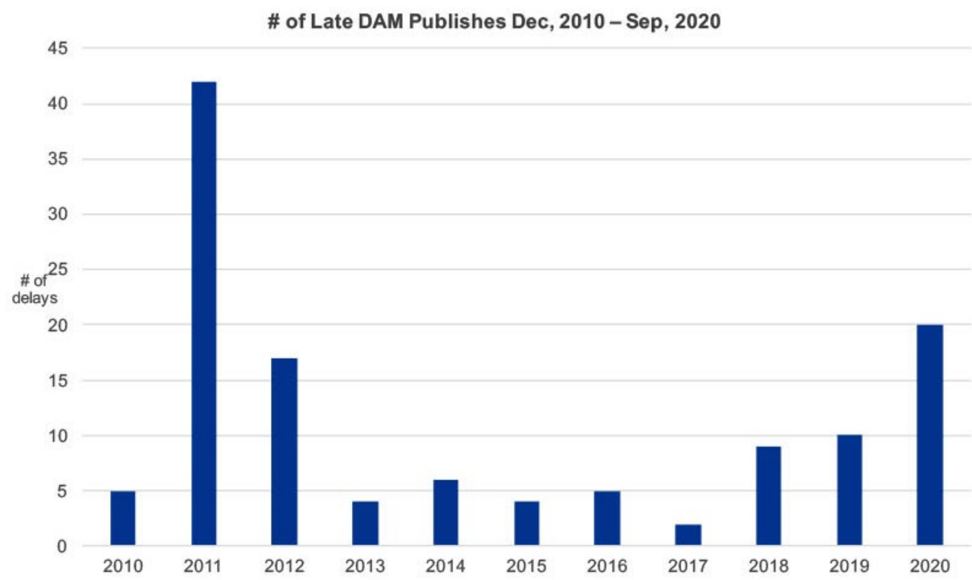
The grid operator allots three-and-a-half hours for the DAM's execution, during which software must optimize its time, validate data inputs, execute the price-validation tool and post results, among other tasks. Input/output verifications and data errors can also lead to delays.

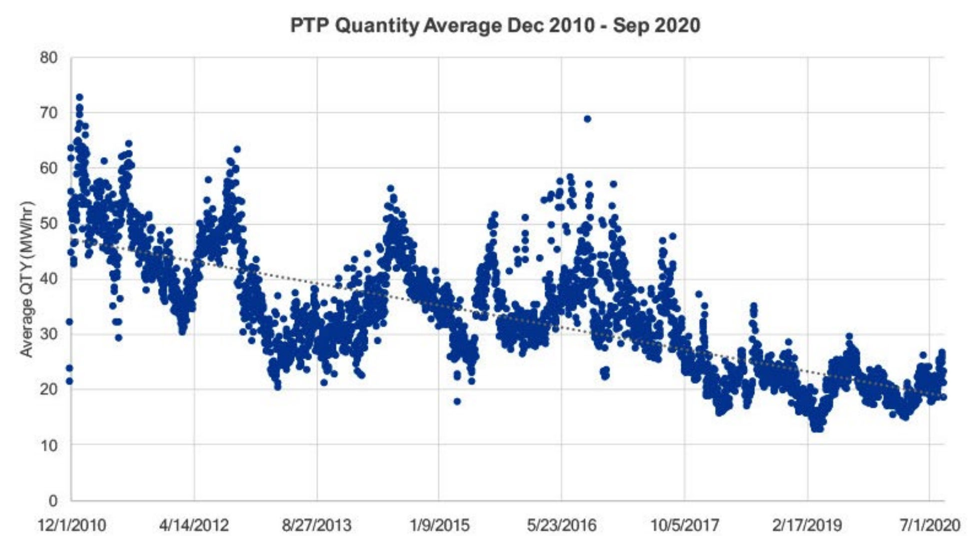
"There's a lot of iteration in the DAM's execution. Because of those iterations and other factors, we could have long run times to clear the DAM," said Kenan Ögelman, ERCOT vice president of commercial operations. "If we get more than 170,000 [point-to-point (PTP) interval] submissions, we'll pretty much have a DAM delay. An increase in settlement points can also lead to long run times."

Ögelman said DAM participation has trended upward, with PTP bids largely contributing to the increased variables. Energy bids and energy-only bids have also grown, and binding constraints are on an upward path.

He said staff haven't been "sitting on our hands," but going after low-hanging fruit — "easy for us to do on our own," Ögelman said — has resulted in staff falling further behind in solving the problem.

"We would like to engage stakeholders in an organized basis," Ögelman said. "When I look at the solutions before us, they all have some drawbacks. I'm not seeing some perfect, low-cost solution without adverse effects."





ERCOT has seen increasing delays in its day-ahead market, driven in part by more granular point-to-point bids. | *ERCOT*

TAC Approves 7 Changes, Tables 8

The TAC's unanimously approved consent agenda resulted in the approval of four NPRRs, a system change request and single revisions to the Planning Guide and Settlement Metering Operating Guide. Eight other change requests were tabled while they wait on their related NPRRs.

- *NPRR1028*: requires qualified scheduling entities to notify ERCOT of physical limitations on their resources' starting ability that are not modeled in the reliability unit commitment software and excuses compliance with parts of RUC dispatch instructions that violate a notified resource's physical limitations. The NPRR also establishes a requirement that ERCOT extend a RUC commitment to honor a resource's minimum run-time limitation when a physical limitation delays its ability to reach its low sustained limit.
- *NPRR1031*: requires ERCOT to post operations messages informing market participants when load is curtailed because of a transmission problem.
- *NPRR1032*: limits the DC tie schedules used in RUC optimization and settlements to the ties' physical rating.
- *NPRR1041*: adjusts the expiration of the protected information status of wholesale storage load data from 180 days to 60 days, aligning the disclosure of real power consumption and metered generation output to 60 days after each operating day.
- *PGRR023*: adds a requirement that transmission service providers submit and annually review a list of contingencies for their portion of the system, ensuring that the appropriate contingencies are submitted for ERCOT and NERC planning criteria.
- *SCR812*: creates an Intermittent Renewable Generation Integration report similar to wind and solar power production integration reports.
- *SMOGRR023*: provides an option for a professional engineer's nameplate certification of newly installed or replaced instrument transformers when nameplate photos cannot be physically accessed, and replaces a list of instrument transformer nameplate data requirements by referencing Institute of Electrical and Electronics Engineers standards. ■

— Tom Kleckner

ISO-NE News

RI Opens Solicitation for 600 MW of Offshore Wind

By Jason York

Rhode Island Gov. Gina Raimondo (D) last week announced a new competitive solicitation to procure up to 600 MW of offshore wind energy.

The governor in January signed an executive order committing Rhode Island to meet 100% of its electricity demand with renewables by 2030. The order directed the state Office of Energy Resources to conduct economic and energy market analysis and develop policies and programs such as the OSW request for proposals.

Raimondo also recently joined with the governors of Connecticut, Maine, Massachusetts and Vermont to issue a joint statement calling for reforms to ISO-NE, saying the RTO is frustrating their efforts to reduce economy-wide greenhouse gas emissions. (See *New England Governors Call for RTO Reform*.)

"In the face of global climate change, Rhode Island must drive toward a cleaner, more affordable and reliable clean energy future," Raimondo said in a statement Oct. 27. "It is critical that we accelerate our adoption of carbon-free resources to power our homes and businesses while creating clean energy jobs. In January, I set a nation-leading goal for Rhode Island to meet 100% of its electricity demand with renewables by 2030. Offshore wind will help us achieve that bold but achievable goal while creating jobs and cementing our status as a major hub in the nation's burgeoning offshore wind industry."

Rhode Island is home to North America's first operational OSW farm off Block Island, and the 400-MW Revolution Wind offshore project received state approval in 2019.

The RFP will be developed by National Grid with oversight by the Office of Energy Resources and is ultimately subject to approval by the Public Utilities Commission.

"Our state, communities and local economies are facing unprecedented challenges as we confront the COVID-19 pandemic, but now more than ever, it's imperative that we lean into our shared commitments to enable and progress the clean energy transition," said Terry Sobolewski, president of National Grid Rhode Island. "Expanding large-scale renewables across Rhode Island is crucial to delivering clean, reliable, affordable energy for our customers and future generations."

A draft RFP will be filed with state regulators this fall. If approved, a final RFP will be issued early next year. Any contracts for OSW projects resulting from the competitive process additionally require separate regulatory approvals.

State	State Target (MW)	MW Selected
Maine	-	12
Massachusetts	3,200	1,604
Rhode Island	1,030	430[1]
Connecticut	2,000	1,108
New York	9,000	1,826[2]
New Jersey	7,500	1,100[3]
Maryland	1,200	368
Virginia	5,200	12[4]
Total	**29,130**	**6,460**

[1] Rhode Island announced Oct. 27 it will issue a solicitation for an additional 600 MW.
[2] New York: Currently procuring 2,500 MW
[3] New Jersey: Currently procuring 2,400 MW
[4] Virginia: Dominion has announced that it will install 2,640 MW of offshore wind project.

State OSW targets | *States of Massachusetts and Rhode Island*

Goal 'Within Reach'

"Offshore wind is a vitally important renewable resource that will help power our decarbonized future — both here in Rhode Island and throughout New England," said state Energy Commissioner Nicholas Ucci. "Importantly, offshore wind can also help our electric system meet winter peak demand with stability-priced clean electricity, helping temper power price spikes faced by local homes and businesses."

Ucci said the RFP, "coupled with other locally developed, carbon-free resources and a continued commitment to robust, cost-effective energy efficiency," puts the state's 100% renewable goal "within reach."

"I am committed to ensuring that Rhode Island leverages the benefits of market competition to secure cost-competitive renewables and reduce long-term energy costs while fostering clean energy jobs and mitigating greenhouse gas emissions across our economy," Ucci said.

Rhode Island had 933 MW of renewable energy in its portfolio as of the second quarter of 2020, representing a ninefold increase since 2016. The state target from OSW energy is 1,030 MW, with 430 MW currently selected and the potential addition of 600 MW, which would meet the target.

Rhode Island Secretary of Commerce Stefan Pryor added: "Among U.S. jurisdictions, Rhode Island is the pioneering state in the offshore wind field. Given its first-in-the-water status, Rhode Island has positioned itself as a premier destination for offshore wind companies, suppliers and related enterprises. Under Gov. Raimondo, we are pleased to be pursuing a second significant expansion of our turbine constellation, and we look forward to partnering with the industry and key stakeholders to ensure the success of this expansion."

Northeast Clean Energy Council President Peter Rothstein said the next 10 years "must be a decade of action" to reduce greenhouse gas emissions by procuring more renewable resources.

"With this announcement, Gov. Raimondo recognizes that investments in offshore wind not only move us closer to 100% renewable electricity, but also put Rhode Island in a pole position to reap the economic benefits that this industry will deliver," he said. ■

ISO-NE News

Vineyard Wind Reaches Tx Agreement with ISO-NE

By Jason York

Vineyard Wind announced Wednesday that it reached a transmission agreement with ISO-NE to deliver power to the RTO's grid from Vineyard Wind 1, the first large-scale offshore wind project in the U.S.

A joint venture of Avangrid Renewables and Denmark's Copenhagen Infrastructure Partners, Vineyard is building the 800-MW wind farm 15 miles off the coast of Martha's Vineyard, Mass.

Vineyard said the agreement would provide "clean, renewable and cost-effective energy" for more than 400,000 homes and businesses across Massachusetts and reduce carbon emissions by more than 1.6 million tons per year.

"We're very pleased to reach this agreement, another important milestone in a project that will bring an entirely new industry to the U.S.," Vineyard Wind Deputy CEO Sy Oytan said in a statement. "There is tremendous potential for job creation, not just during construction but also for operations and maintenance. These are good-paying jobs that will be around for decades to come."

In September, FERC approved the company's execution of the *interconnection agreement* with the RTO, effective July 10. The agreement allows Vineyard Wind 1 to interconnect at the 115-kV Barnstable switch station on Cape Cod. Vineyard was selected to enter into power purchase agreements with electric distribution companies as part of the Massachusetts Green Communities Act offshore wind solicitation.

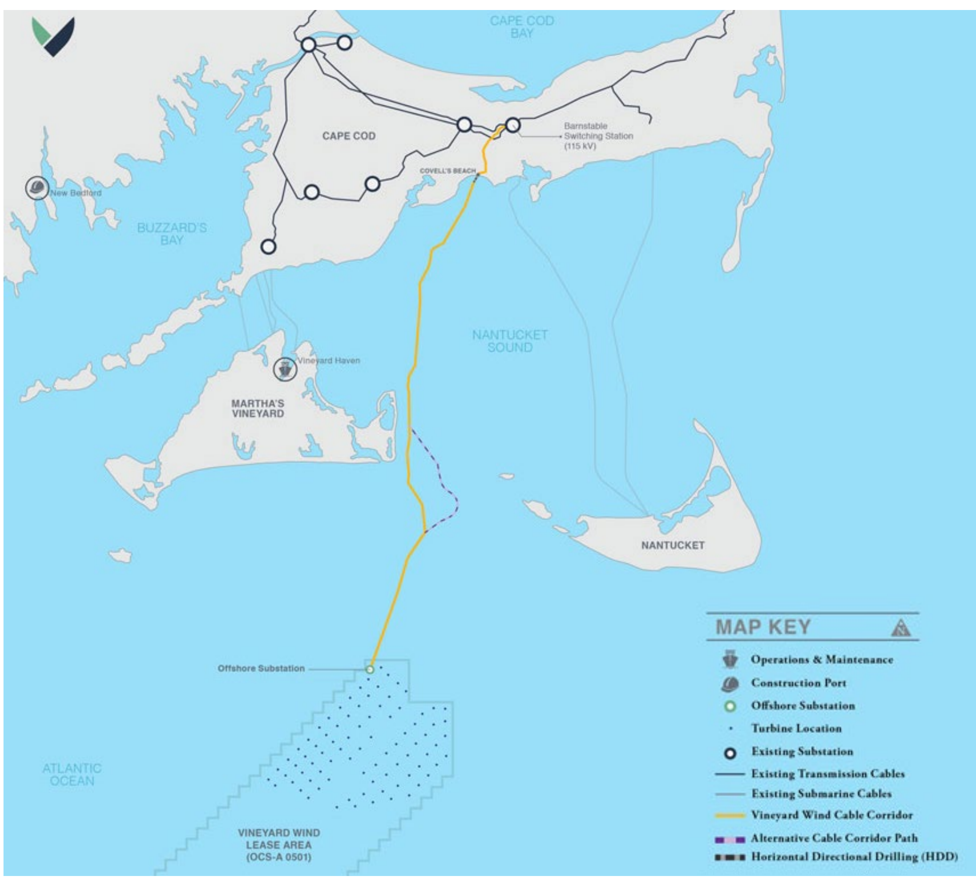
At FERC's technical conference on OSW transmission Oct. 27, Al McBride, director of transmission services and resource qualification, said there is room for the region's power system to accommodate the initial wave of projects, but connecting further projects would be more expensive as this "low-hanging fruit" is used on the transmission system.

ISO-NE spokesperson Matt Kakley said Wednesday that McBride's observation reflected the 2019 Economic Studies for the New England States Committee on Electricity and Anbaric Development Partners. It estimated that injecting 7,000 MW of OSW capacity at optimal locations could avoid significant reinforcements to the 345-kV transmission system. Injections above 7,000 MW would require additional power plant retirements or support to the onshore transmission system, the report concluded.

"We're looking forward to discussing with the New England states and market participants how to best shape the development of the regional grid to accommodate regional policy goals, under the authority provided by the ISO's tariff and under any needed enhancements to the ISO's planning scope." Kakley said.

Speakers at the technical conference said the efficient development of offshore transmission will require changes to current planning, interconnection and cost allocation procedures. (See related story, *FERC Pushed to Change Tx Rules for OSW*.)

A *white paper* released Oct. 26 by the Business Network for Offshore Wind stated that RTO processes fail to capture all the benefits from offshore transmission, particularly an inter-regional network that could improve ISO-NE resilience. (See *OSW Group Seeks Changes on Tx Planning, Cost Allocation*.) ■



| Vineyard Wind

ISO-NE News

FERC Rejects ESI Market Design from ISO-NE

NEPOOL Alternative also Rebuffed

By Jason York

FERC ruled Friday that ISO-NE's proposed Energy Security Improvements (ESI) market design is "unjust and unreasonable" because it would add substantial costs "without meaningfully improving fuel security" (*ER20-1567*).

ESI would have allowed the RTO to procure energy call options for three new day-ahead ancillary service products to improve the region's energy security, particularly in winter when natural gas shortages can leave generators without fuel. Option awards would have been co-optimized with all energy supply offers and demand bids in the day-ahead market.

FERC found that the RTO's proposed day-ahead ESI products "do not provide enough time for resources to take the steps necessary to perform during stressed conditions if they have not already taken them" as arranged fuel, for example. The proposed market design would have allowed resources that have not made advance arrangements to not participate because of its voluntary nature, undermining its ability to address fuel security. The commission noted that the impact assessment produced for the RTO by Analysis Group said ESI "would not materially reduce reserve shortages or the potential for loss of load, but nevertheless, forecasts increased costs of $20 million to $257 million per year."

FERC also rejected an alternative proposed by NEPOOL that would have resulted in lower costs to ratepayers than the RTO's proposal, saying it contains the same deficiencies.

FERC said that although it "does not generally require the mathematical specificity of a cost-benefit analysis to render a proposal just and reasonable ... the commission must protect consumers from excessive rates and charges. In light of our finding above that ISO-NE fails to demonstrate that ESI will materially improve fuel security, we find that ESI does not strike an appropriate balance between addressing fuel security in New England while protecting consumers from the significant cost of those fuel security benefits."

The commission said the RTO's proposal also does not adequately address the misaligned incentives problem: fuel-secure resources may not be sufficiently motivated to make additional investments in energy supply arrangements. ISO-NE currently relies on resources that might not be available during stressed conditions because it did not procure the necessary fuel or resources with energy storage capabilities and did not take the steps needed to produce energy during stressed conditions.

"We find that, while the procurement of day-ahead reserves or call options allows ISO-NE to procure additional resource capability one day prior to real time, the record in this proceeding demonstrates that one day is not a sufficient time frame for resources to take the steps necessary to perform during stressed conditions," the commission wrote.

The RTO pointed to the results of the impact assessment to claim that ESI would create strong financial incentives for resources "to

| *National Grid*

ISO-NE News

maintain more secure energy supplies without an associated forward market." According to FERC, ISO-NE failed to demonstrate how such incentives would be meaningful to resources that are unable to adjust energy supply arrangements in the day-ahead time frame.

NEPOOL Proposal

The RTO's proposal had failed to win NEPOOL stakeholders' endorsement, garnering only 39.6% support at a Participants Committee vote in April. Although Generators, Suppliers and Alternative Resources generally approved the plan, the other sectors were unanimous in opposition.

The committee endorsed a proposal by the New England States Committee on Electricity by a 61.7% sector-weighted vote, with unanimous support from the Transmission, Publicly Owned Entity and End User sectors and unanimous opposition from Generators. (See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

But FERC said the NEPOOL's alternative "fails to sufficiently align the timing of reserve procurement with that of fuel procurement and maintains the voluntary nature. … Furthermore, the impact assessment demonstrates that the NEPOOL alternative would not materially reduce reserve shortages or the potential for loss of load."

The result of more than a year of stakeholder meetings, the ESI proposal was prompted by FERC's July 2018 finding that ISO-NE's Tariff is not just and reasonable because the RTO lacks a way to address fuel security concerns that it said could result in reliability violations as soon as 2022. The Tariff currently allows cost-of-service agreements only to respond to local transmission security issues. (See *FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes*.)

But FERC said Friday it made no finding on whether the RTO faces fuel security or energy security problem.

"We recognize that ISO-NE has concerns about its current and future ability to reliably serve load given its growing reliance on 'just-in-time' resources such as pipeline-fed natural gas and renewable generation, which could have efficiency and reliability consequences," the commission wrote. "If ISO-NE decides to pursue a solution to address these concerns, we encourage it to explore a market-based reserve product that provides resources sufficient lead time and ability to acquire fuel or take other steps necessary to be able to deliver energy when needed."

FERC added that it expected a market design would coordinate procurement of forward reserves and incentivize resources to offer into the forward, day-ahead and real-time energy and reserves markets based on their actual costs. It should also prevent the exercise of market power, including through potential mitigation measures and include financial obligations or incentives sufficient to ensure resources can deliver energy or reserves in real time.

"We are not, however, directing ISO-NE to pursue any particular approach," the commission wrote. "We further note that nothing in this order prohibits ISO-NE from proposing a day-ahead reserves market independent of any proposal to address the concerns at issue here."

The ruling also rejected ISO-NE's proposal to sunset the interim fuel security retention mechanism and the inventoried energy program one year earlier than currently set in the Tariff.

ESI "would not materially reduce reserve shortages or the potential for loss of load, but nevertheless, forecasts increased costs of $20 million to $257 million per year."

—Analysis Group

"We're reviewing the decision and will discuss next steps with stakeholders," ISO-NE spokesman Matt Kakley said. "We remain committed to finding market-based solutions to solving the region's energy security challenges."

Attorneys for Day Pitney said they "are continuing to digest the implications of the order, including potential next steps for NEPOOL and ISO-NE, and will provide additional information if and as appropriate." ■

ISO-NE News

Conn. Stakeholders Talk Storage, Order 2222

By Michael Kuser

A webinar panel on Oct. 26 discussed how different energy storage technologies are coming to market in Connecticut, the various state targets and incentives, and the challenges for developers in working with both state-sponsored projects and the wholesale electricity markets.

"Connecticut is really trying to get into the game when it comes to energy storage," said Public Utilities Regulatory Authority (PURA) Chair Marissa Gillett, who moderated the discussion for more than 50 members of the Connecticut Power and Energy Society.

"Last session ... we saw the chair of our Energy and Technology Committee, Rep. David Arconti, introduce House Bill No. 5351, which would have established an energy storage target for the state by Dec. 31, 2020, of 1,000 MW," Gillett said. "While that bill did not receive an up or down vote due to the coronavirus suspending all activities in the legislative session, PURA has been moving forward on its energy storage dockets as part of our Equitable Modern Grid proceeding." (See *Conn. Lawmakers Seek to Balance Energy Goals, Costs*.)

State Targets

While it's important to have federal policies, "the name of the game" is states setting targets, promoting incentives and including storage in their planning, Energy Storage Association CEO Kelly Speakes-Backman said.

"Incentives are sending the signals to companies like ENGIE and Key Capture to know that it's OK to come and open up business in the state," she said.

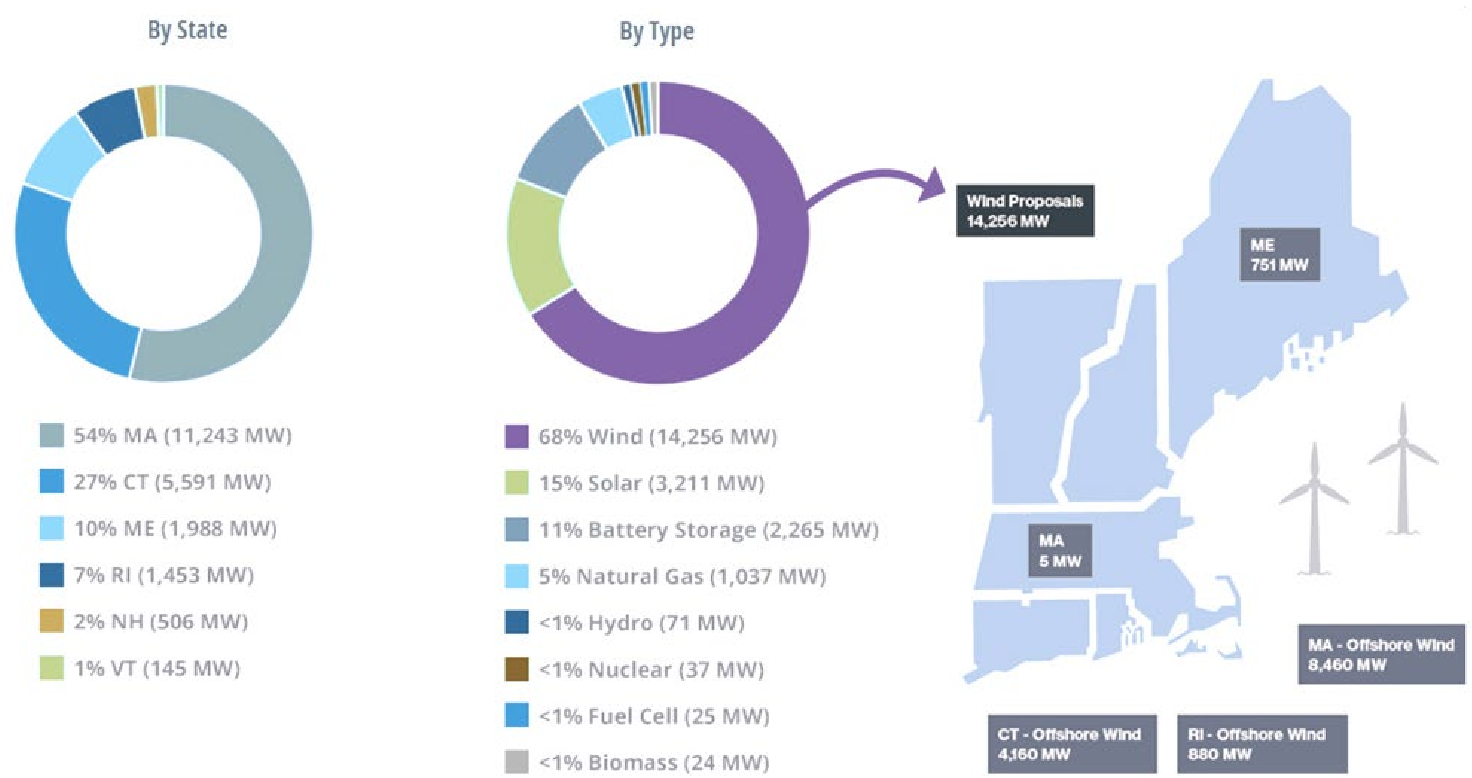
Speakes-Backman said FERC Order 2222, which directed RTOs and ISOs to open their markets to distributed energy resource aggregations, is "all to the good, but massively disruptive." (See *FERC Opens RTO Markets to DER Aggregation*.)

"What I'd like to see ultimately come out of Order 2222 is a system of aggregated [DERs] that can ride through ... short-term outages like we saw in California" in August and September, Speakes-Backman said. "I want to see this two-way system ... [where] buildings can act as a generation source and vehicles can participate in grid systems. Order 2222 starts to get us towards that mix between what's at the distribution level and what's at the wholesale level."

"I want to see this two-way system ... [where] buildings can act as a generation source and vehicles can participate in grid systems. Order 2222 starts to get us towards that mix between what's at the distribution level and what's at the wholesale level."

—Kelly Speakes-Backman, CEO of Energy Storage Association

Order 2222 is considered to be a companion order to Order 841, "and we hope it will do for DER aggregations the same thing that 841 did for storage," said Sarah Bresolin Silver,



As of January 2020, battery storage comprised about 11% of the 20,100 MW proposed in the ISO-NE generator interconnection queue. | *ISO-NE*

ISO-NE News

director of government and regulatory affairs and wholesale markets policy at ENGIE North America.

The order is important because it requires ISOs and RTOs to establish participation models DER aggregations and accommodate all the physical and operational characteristics of those aggregations, she said.

"The goal is to have these assets participate in the wholesale markets without too much burden and perhaps someday without the need for state incentives, [so,] we have to be involved in ISO-NE stakeholder processes to make sure that any changes made welcome these resources into the markets."

Clockwise from top left: Rachel Goldwasser, Key Capture Energy; Sarah Bresolin Silver, ENGIE North America; Kelly Speakes-Backman, Energy Storage Association; and Connecticut PURA Chair Marissa Gillett. | *CPES*

Bridging the Regulatory Gap

Rachel Goldwasser, a lead legal adviser at *Key Capture Energy*, an Albany-based developer with several projects operating or under construction in New York and Texas, said that ERCOT is much different from ISO-NE.

"There's no capacity market, and the model the market is built on expects price volatility and expects investment to follow that price volatility," Goldwasser said. "When you couple that with significant expansion of wind energy, and some level of congestion permitted on the transmission system, you end up building a marketplace that supports the development of storage and certain applications in certain environments and locations."

In ERCOT, the company doesn't have to worry about a minimum offer price rule (MOPR) or about clearing the capacity market, she said. It can go wherever the grid needs storage to be deployed.

"ERCOT is fun because it's just a market, and you can find economic ways of doing storage," Goldwasser said.

New York is a different story, she continued. From a regulatory perspective, NYISO is a close sibling of ISO-NE.

She said the grid operators' capacity markets are "an ongoing concern that we hope will be less of one over time. But we also have established *programs* in New York to support storage; there's the market bridge incentive program, and utility procurements ... and a program causing retirement of fossil fuel generators there, peaking plants in particular."

It takes time to bring all stakeholders together, including ratepayers, Speakes-Backman said.

"There is a very methodical step from the regulatory perspective in including storage, and that's why legislation is so important: It creates a bridge of incentives and targets so that businesses know that there is a path forward to make it worth investing in," Speakes-Backman said.

"One of the biggest challenges we've had, and I think this is true of a lot of renewable energy and storage companies with respect to the MOPR and market monitoring ... is around managing the state-facilitated projects and the wholesale markets together," Goldwasser said.

A second issue is the unique nature of storage.

"How do the withholding rules work? What is economic discharge? How do you think about the deployment of a battery over 24 hours in the energy market with respect to what would traditionally be seen as market monitoring concerns?" Goldwasser said. ■

NECA Panel Ponders Forward Clean Energy Market

Stakeholders Seek Ways to Help States Reach Decarbonization Goals

Clockwise top from left to right: David O'Connor, ML Strategies; Greg Cunningham, Conservation Law Foundation; Peter Fuller, Autumn Lane Energy Consulting; Rebecca Tepper, Massachusetts Attorney General's Office; and Michelle Gardner, NextEra | *NECA*

By Jason York

New England stakeholders frustrated by states' inability to meet their clean energy goals within ISO-NE's markets considered last week whether a forward clean energy market (FCEM) might provide a solution.

"I think it's fair to say that the idea of a forward clean energy market … is one that seems to have great salience for the challenges we face here in the region," Peter Fuller, principal and founder of Autumn Lane Energy Consulting, said during a Northeast Energy and Commerce Association webinar Wednesday. "It's one that people have felt ought to be given serious consideration by the states, NEPOOL, the Federal Energy Regulatory Commission and all of the many stakeholders really interested in the success of that market."

As *proposed* by The Brattle Group, 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 similar to a renewable energy credit (REC). One variation, a "dynamic" CEAC, would award more credits to resources that displace more carbon emissions, focusing incentives on achieving more carbon abatement faster. 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. (See *NEPOOL Reconsiders Forward Clean Energy Market*.)

Fuller said it is "becoming increasingly clear that the wholesale market can and should be changed" to address states' carbon-reduction goals.

In recent years, partly because the wholesale market was not delivering clean energy to the degree that several New England states wanted, they have utilized long-term contracting and procurements of solar energy and offshore wind.

"It may be that a more robust competition between resources that can deliver carbon-free energy [is] both more reliable and more cost-effective for ratepayers; that's at least the hope related to the forward clean energy market," Fuller said.

Federal-State Conflicts

He said the FCEM design would address the conflict between state and federal policymakers on issues such as the minimum offer price rule (MOPR) and Competitive Auctions with Sponsored Policy Resources (CASPR), a two-tiered capacity construct intended to prevent consumers from paying twice for the same capacity through both the Forward Capacity Market (FCM) and subsidies for state-mandated resources.

"We think FCEM can be a vehicle to address that conflict," Fuller said.

Michelle Gardner, senior director of regulatory affairs in the Northeast for NextEra Energy Resources, added that "looking at the massive transition that we're anticipating over the coming decades, to me this is really about harnessing the competition and the balance between both new and existing resources." She said states could do solicitations for existing resources, "but for the most part, the existing resources in the market that do contribute to carbon abatement are not valued."

Rebecca Tepper, chief of the Massachusetts Attorney General's Office Energy and Telecommunications Division, said that "markets are not going to bring us to or sustain a low-carbon future as they are currently designed."

At a symposium the AG's office held last year, two reasons were cited for why the markets were not working, Tepper said.

"One, it wasn't bringing in the renewables, because of the MOPR, and that was resulting in double-counting," Tepper said. "And two was resource adequacy. The forward clean energy market addresses No. 1, but it's not designed to address No. 2."

While the current system design is based on peak-hour demand, a transition to more clean

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energy will require availability at all hours of the day, Tepper said.

"We're going to need to value other products like ramping and storage and others to incentivize them to address resource adequacy," Tepper said.

Do the states have to control or have a more significant influence on an FCEM to work? Fuller said the market design "would be explicitly designed to create a high degree of control for the states."

"I think who does the market administration is less important than making sure that it's done in a way that passes muster in terms of nondiscriminatory competition among sources," said Fuller, who added that the ultimate idea is to procure a generalized low-carbon product at the lowest possible cost.

Greg Cunningham, vice president and program director for clean energy and climate change at the Conservation Law Foundation, said existing programs such as state renewable portfolio standards could work with an FCEM.

"It's conceivable that a form of RPS compliance could be participation in this market," Cunningham said. "It obviously would have potentially negative implications for the REC market."

Cunningham said he also appreciated Tepper's concern about redundant costs.

"Striking the balance between the onset of a new [market] and moving away from the old one in a timely fashion so that we have the certainty that we as consumers in our homes and businesses and industries want from an electrical availability perspective but also from a cost perspective — that's essential," Cunningham said.

Could an FCEM address resource adequacy? There is "a lot of promise there to look at [the Forward Capacity Market and FCEM] in a combined fashion and a lot of efficiencies" Fuller said.

"Nothing that is going on with FCEM would alter or diminish the role of ISO[-NE]'s existing programs to maintain resource adequacy and reliability," Fuller concluded. "The ISO's capacity market might need to evolve in response to more clean energy with different attributes and characteristics than the fossil-fueled stuff that we've all become accustomed to, but those are going to happen whether we have an FCEM or contract-based system. We're going to have to evolve to a bit of a different system. Nothing here would undermine resource adequacy, even though nothing in FCEM addresses resource adequacy directly." ■

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*

NEPOOL Continues Discussions on FCM Parameters

Markets Committee Votes on Parameters and Amendments Set for Nov. 9-10

By Jason York

The NEPOOL Markets Committee continued its discussion last week on Forward Capacity Market (FCM) parameters for the 2025/26 capacity commitment period.

Concentric Energy Advisors (CEA) and Mott MacDonald, two consulting firms hired by ISO-NE, *presented* updates to their analyses from the previous meeting on the net cost of new entry (CONE) and offer review trigger prices (ORTPs). ISO-NE also *presented* its input assumptions and updated values for CONE, OTRPs and the performance payment rate while *proposing* a smoothing mechanism for the peak load scarcity hour estimates used to calculate those values.

The Oct. 26 meeting preceded Friday's FERC ruling that ISO-NE's proposed Energy Security Improvements market design is unjust and unreasonable because it would add substantial costs "without meaningfully improving fuel security." FERC also rejected an alternative proposed by NEPOOL that would have lower costs to ratepayers than the RTO's proposal, saying it contains the same deficiencies. (See related story, *FERC Rejects ESI Proposal from ISO-NE*.)

Proposed Smoothing Mechanism

Expected capacity scarcity condition (CSC) hours are based on three sources: peak load scarcity hours, transient scarcity hours, and winter scarcity hours. ISO-NE updates the peak load scarcity hours estimate annually after its update to the installed capacity requirement.

ISO-NE said the estimated CSC hours for Forward Capacity Auctions 11 through 15 ranged from a low of 7.9 to a high of 14.1, with considerable volatility in recent year-over-year changes. The RTO said it wants to use a four-year moving average to establish the expected peak load scarcity hours for FCM parameters. It said four years aligns with the load forecast horizon and that the current four-year average (10.1 hours) differs little from the three- and five-year averages. In the net CONE calculation for FCA 16, total expected annual scarcity hours, including transient (0.8 hours) and winter (0.4 hours), becomes 11.3 hours with the smoothing mechanism, down from 15.3 hours.

ISO-NE also summarized its reasons for updates to the net CONE, performance payment rate (PPR) and ORTP proposed values. The RTO is also proposing changes to the PPR because of the revised peak load scarcity hours and reference technology assumptions.

Capacity values and energy and ancillary services revenues were adjusted to reflect degradation over the net CONE reference unit's life in response to stakeholder feedback, affecting gross CONE, net CONE and PPR.

Operations and maintenance costs for net CONE reference technology were revised to reflect decreased dispatch activity consistent with the unit's low heat value, and bonus depreciation was removed, impacting gross CONE and PPR.

The RTO also revised the site leasing rate for the battery technology that impacts only battery ORTP.

NEPGA Memo

The New England Power Generators Association (NEPGA) presented several amendments at the Markets Committee meeting Oct. 6-8. (See "NEPGA Proposes Amendments on Amortization Period, Owner's Cost," *NEPOOL Debates Parameters for 2025/26*.) In a *memo* to the committee for this meeting, NEPGA's Bruce Anderson wrote that several NEPOOL stakeholders asked the group to estimate the impact each of its potential amendments would have on net CONE value.

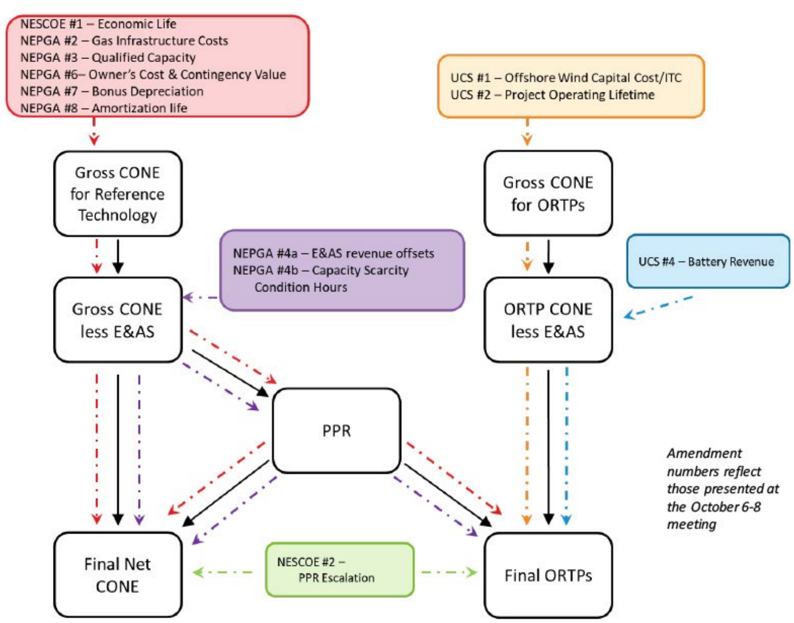
NEPGA *posted* a modified version of the discounted cash flow model used by CEA in the current net CONE recalculation process to show the numerical inputs it proposes as amendments to the bonus depreciation line item. These inputs derive from analysis and conclusions drawn by Advantage for Analysts on behalf of NEPGA. Stakeholders cannot reproduce the calculation of the inputs, so NEPGA provided them and their impact on net CONE to stakeholders who want to reproduce any of its analyses.

Impact Assessment

ISO-NE said the interdependencies among the FCM parameters present unique challenges when calculating the combined effect of more than one amendment on CONE, net CONE, ORTP and PPR values, as many amendments will impact more than one parameter. For example, a change in gross CONE for the reference technology has downstream impacts on the PPR and all ORTP values, according to the RTO.

ISO-NE said it would attempt to validate the impact of individual amendments before next week's committee meeting, but given "the numerous permutations required to assess all combinations, the ISO cannot determine the impact of hypothetical combinations of amendments ahead of the November MC meeting nor calculate results in real time at that meeting."

If any amendments pass at the MC meeting, the RTO will calculate their combined impacts on CONE, net CONE, ORTP and PPR and publish them before the Participants Committee vote Dec. 3. ■



Impacts of proposed amendments on FCM parameters, according to ISO-NE | *ISO-NE*

MISO News

MISO: Winter Could Get Tricky Despite Forecast

By Amanda Durish Cook

MISO should have adequate capacity to navigate winter but could still face abnormal weather-related generation outages or a load-shedding event, RTO officials said Wednesday.

The RTO *expects* to have 146 GW of available capacity to manage an expected 104-GW winter peak, 5 GW less than its all-time winter peak on Jan. 6, 2017.

Executive Director of Real-Time Operations Rob Benbow said anticipated electricity usage paired with the "outages we have planned" show adequate reserves.

But as usual, a combination of high demand and unexpectedly high generation outages could put MISO operations in jeopardy.

"I think we all know that unforeseen events and outages can change our position, and we will work with members to mitigate issues and ensure the reliable and efficient operation of the grid," Benbow said during a winter readiness teleconference.

"I believe it's important to spend time on winter readiness just as much as we talk about summer readiness," he added.

Using a high-load, low-generation forecast, MISO said it could exhaust all 10.5 GW of its load-modifying resources (LMRs) on a January peak day and be forced to order load-shedding from members. Using the more likely forecast provided by its market participants, a high-demand, peak day in January containing a more typical number of outages could still force MISO to declare an emergency to access some of its LMR stack. If winter conditions are harsh enough, the grid operator said it could tie its 109-GW all-time winter peak.

Resource Adequacy Coordination Engineer Eric Rodriguez said December and January bring the highest risk of a maximum generation event.

"MISO is planning minimal risk in February, which appears to be a preferential time to schedule generation outages," Rodriguez said.

Last winter, MISO's generation outages trended lower than its five-year average, averaging about 22 GW.

The National Oceanic and Atmospheric Administration is forecasting above-average temperatures this winter in MISO South and

| *MISO*

"I think we all know that unforeseen events and outages can change our position, and we will work with members to mitigate issues and ensure the reliable and efficient operation of the grid."

—Rob Benbow, Executive Director of Real-Time Operations

lower-than-normal temperatures for Minnesota, Wisconsin and the Dakotas (Zone 1). The agency also *predicts* more precipitation than usual in MISO Midwest and a drier winter for South.

"The past 10 winters have been within 10% of NOAA's predictions," Rodriguez said.

Director of Balancing and Interchange Operations Tag Short said MISO has *undertaken* dramatically more winter preparation since the polar vortexes and subsequent maximum generation events of 2014 and 2019 and the two-day MISO South emergency in January 2018. Since the Midwestern arctic blast in 2019, the RTO has been including the cold-weather cutoff thresholds of wind generators.

"We do have a pretty good ledger now of extreme temperatures," Operational Forecast Planner Adam Simkowski said, adding that MISO now factors public building and college closures into its load forecasting. He said polar vortexes tend to produce more subdued, weekend and holiday-style forecasts.

MISO's Geoff Brigham also said generators this winter can turn to the RTO's *multiday operating margin forecast*, launched last November, to help make commitment decisions. The forecast shows a week-ahead expected supply picture.

The RTO is also exploring publishing multiday outage and derate information, Brigham said.

Generation and Balancing Authority Operator Michael Carrion said MISO's approximately 200 natural gas generators representing 70 GW have ample access to basins, pipelines and storage by virtue of the RTO's broad territory.

Carrion reported that the Midwest's natural gas storage levels are above the five-year historical range and "nearing the five-year maximum storage threshold due to strong production, reduced load and relatively mild temperatures."

MISO also doesn't expect any unusual transmission limitations this winter.

Meanwhile, NERC is still making progress on developing cold weather standards, spurred by MISO South's early 2018 emergency, staff said. (See *FERC Orders Cold Weather Reliability Standard*.)

Principal Adviser of Standards and Assurance Bobbi Welch said NERC has landed on a

MISO News

scope for the cold weather preparation rules, which will rely on existing plant winterization standards and communications on generation capability.

The standard might be nothing more than business-as-usual, especially for generator owners and operators in the northern portions of MISO's footprint, Welch said.

"They're hoping that this will make it more palatable," she said. "It's going to take a look as a system on how we get ready for winter weather."

In a 2019 report on the MISO South emergency, FERC and NERC concluded that generation owners failed to properly winterize their equipment, contributing to the supply crunch.

Welch said the standards should be ready for use in late 2021, "about a one-year horizon."

A Rising Winter Risk

The cold weather standards are being developed as MISO devotes more time to assessing an emerging wintertime loss-of-load risk.

The RTO has recently said it could define unique seasonal system reliability requirements, hold seasonal capacity auctions and use risk assessments beyond its summer-emphasized loss-of-load study. (See *MISO Lays Out Seasonal Capacity Options*.) The options would have MISO moving away from summer peak modeling and forecasting in favor of determining multiple loss-of-load risk hours throughout the year, called resource adequacy hours.

MISO's current loss-of-load modeling tends to underestimate wintertime risk, a trend that will be exaggerated as the footprint adds more solar generation, MISO analysis shows.

During a special teleconference Oct. 26, MISO Director of Research and Development Jessica Harrison said stakeholders are interested a monthly or seasonal division of capacity auctions.

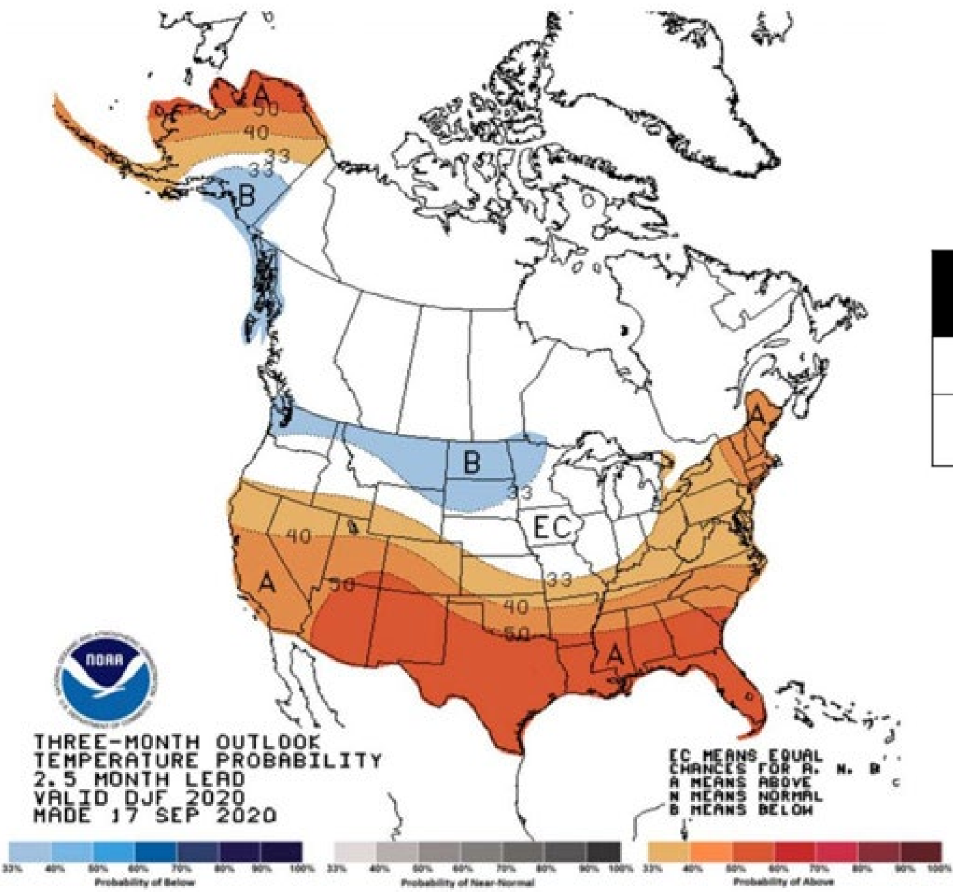
"We want to land on a model that mitigates risk under a variety of resource portfolios," Harrison said, adding that any resource adequacy design must also be practical for MISO to implement.

Senior Manager of Resource Adequacy Coordination Lynn Hecker said it would be easy enough for MISO to incorporate new sub-annual modeling inputs.

Using an expected unserved energy calculation — where MISO calculates the expected amount of energy when load is set to exceed generation — the RTO *found* risk in January, February, May and December, in addition to the prevailing risk in June, July, August and September identified under summer peak loss-of-load modeling.

Using a five-year-out generation portfolio based on queue projections, MISO found risk in every month except April, November and December, with the most pronounced risk occurring in February and September.

Hecker said results using the revised inputs generally track with emergency events MISO has experienced under its current portfolio. Most of its roughly dozen emergency declarations since 2016 have occurred outside of summer months. ■



MISO Preliminary Winter 2020-2021 Forecast	
Winter Peak Forecast	104 GW
Total Projected Available Capacity*	146 GW

All-time Winter Peak:

109 GW on January 6th, 2017

NOAA and MISO winter predictions | *NOAA and MISO*

MISO News

MTEP 20 Passes 1st Board Endorsement

By Amanda Durish Cook

MISO board members last week gave an initial nod to the RTO's $4 billion 2020 Transmission Expansion Plan (*MTEP 20*).

In a special conference call Oct. 26, the four-member System Planning Committee of the Board of Directors voted unanimously to send MTEP 20 to a full board vote in early December.

Director Mark Johnson said the committee's voting took place about a month earlier than usual this year to allow more time for the full board to deliberate about the plan.

MTEP 20's 515 projects include 75 baseline reliability projects, accounting for 18% of the plan's cost, but they still come in $70 million below MTEP 19's crop of baseline projects. It also includes 100 generator interconnection projects, representing 15% of costs.

MISO said it's normal to have boom-and-bust investment years in terms of baseline reliability projects. This year most baseline projects are located within the Central planning region, which account for $372 million.

Executive Director of System Planning Aubrey Johnson said that while MTEP 20's spending tracks closely with the 2019 package, spending on generator interconnection projects increased from $269 million last year to $606 million this year.

"We've seen an almost three times increase of interconnection projects from this year to last, and we attribute that to clearing out some of the [interconnection queue] backlog," he said.

MISO's Planning Advisory Committee approved MTEP 20 in September; however, some members asked that the RTO be more specific about the breakdown of projects in its "other" category. (See "Members Endorse MTEP 20," *MISO Planning Advisory Comm. Briefs: Sept. 23, 2020*.)

The "other" category includes load growth-based projects, age and condition-based upgrades, and economic, environmental and reliability-driven projects. It usually represents the lion's share of MTEP spending, and this year it accounts for $2.8 billion. MISO said 40% of "other" projects are needed for reliability, 36% for age and condition, 21% for load growth and 2% for other local transmission owner needs. RTO executives said some load pockets are experiencing load growth, even if it's not occurring footprint-wide.

"The old proverbial 'other' bucket, I really encourage MISO to refine that. ... It's just a little too nondescript, and I know I'm not the first director to raise this issue with MISO management," Mark Johnson said.

"More definition would be helpful," agreed Director Todd Raba.

MISO executives also briefed the board on the removal of Entergy Louisiana's nearly $74 million, 27-mile, 230-kV, Waterford-to-Churchill transmission line approved as part of MTEP 16. MISO said the line no longer demonstrates the benefits it once did. Over four years, the benefit-cost ratio dropped from 2.3 to about 0.2, according to Entergy. (See "Entergy Cancels MTEP 16 Project," *MISO in Final Stretch of $4B MTEP 20*.)

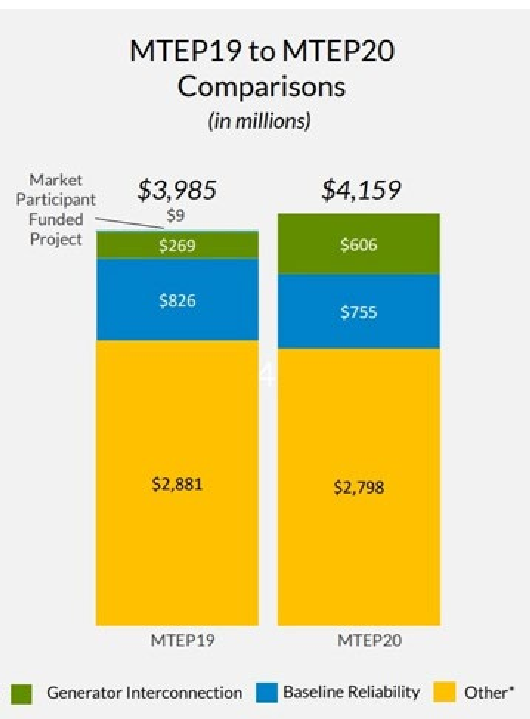
MISO's agreement to rescind the project ruffled some feathers within the stakeholder community this fall.

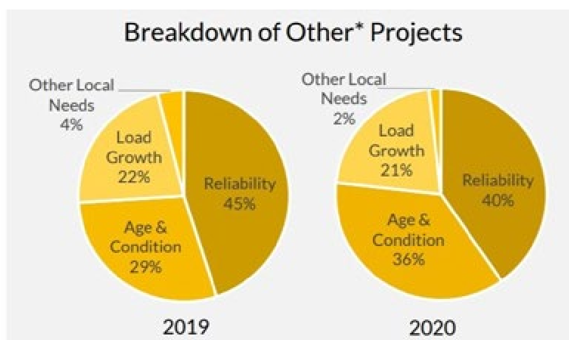
Director Nancy Lange asked whether stakeholders disagreed with the decision to withdraw the project or the opaque manner in which the decision was made.

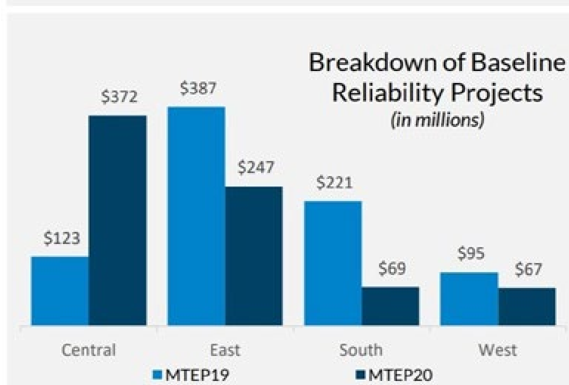
Aubrey Johnson said some stakeholders weren't comfortable with MISO conducting a withdrawal analysis in the background without notifying them of the study's process or progress. He said some argued that MISO didn't provide them time to perform their own no-harm analyses to find out if the project's removal would negatively impact other subsequently approved MTEP projects.

"For this project, I do not believe the benefits are there. Whether we need other transmission in the area is an ongoing question," Vice President of System Planning Jennifer Curran said.

"I think the question is, if you're going to have projects withdraw like this, how do you present that to the stakeholders earlier in the process, if you will?" Aubrey Johnson said. He added that MISO will re-examine its process of monitoring and recommending withdrawal of MTEP approved projects. ■







MTEP 20 stats | *MISO*

MISO News

MISO: Tx Beats Storage in Integrating Renewables

By Amanda Durish Cook

Invenergy's Grand Ridge Battery Storage Facility in Illinois | *BYD*

MISO's shift to renewable resources can be supported by energy storage devices — but only to a small degree, the RTO said Oct. 27.

The final results from MISO's Renewable Integration Impact Assessment (RIIA) show that transmission is still key to economically using an expanding renewable fleet, though strategically placed energy storage can help.

"Storage, without adequate transmission capacity in the system, may help increase renewable energy delivery but may not sufficiently aid in meeting renewable penetration targets," MISO Manager of Policy Studies Jordan Bakke told stakeholders during a special teleconference.

After running the RIIA with storage considerations, MISO found that transmission — not energy storage — remains most effective at delivering a hypothetical 40% renewable share of the resource mix under four study scenarios. However, the RTO said transmission buildout with select storage additions seems to be the most effective way to meet renewable energy goals and "may achieve the best overall value."

Previous results from the RIIA have excluded the role of energy storage expansion, which some stakeholders say is a key consideration in the transition to a primarily renewable generation fleet.

MISO has previously said it can likely operate its system reliably with renewable penetration targets up to 50%, but only if its members engage in dramatic transmission expansion. (See *MISO Renewable Study Shows More Tx, Tech Needed*.) MISO currently operates with about 8% renewables.

"What we found with wind [and] solar generation, the complexity or challenges that that grid faces increases exponentially beyond 30% [penetration]. ... Existing infrastructure becomes inadequate for fully accessing the diverse resources across the MISO footprint. What you need is to change how the grid operates," Bakke said.

MISO Senior Policy Studies Planner Chen-Hao Tsai said storage alone cannot unlock delivery of a hypothetical 96 GW of renewables every hour of the year.

"Beyond 30%, we still need some substantial transmission solutions," Tsai said, adding the transmission need remains the strongest to deliver wind generation from the northern portion of the footprint to load centers.

But MISO said an "optimum" amount of storage can help flatten its load curve and spread out an increasingly narrow loss-of-load risk.

The RTO previously found that as renewable generation grows, its daily loss-of-load risk compresses into a steeper and shorter period later in the evening. (See *MISO Renewable Study Predicts Later Peak, Narrower LOLE Risk*.)

"It will help move that availability around," Bakke said. Storage resources can concentrate charge and discharge times depending on whether reliability risk is high or low, he said, but they are only available for so long, especially batteries.

When MISO offered both transmission and storage as solution candidates in its study simulation, its algorithm chose to build only a modest 0.5 GW of battery storage. When it ordered its algorithm to only select storage solutions to access the 40% renewable energy mix and not transmission, the simulation added 16 GW of storage footprint-wide at a cost of billions of dollars.

Stakeholders seemed taken aback that MISO's optimal simulation would recommend such a small amount of storage.

Bakke said the study focused narrowly on how storage can aid renewable energy delivery and adequacy across all operating hours of the year.

"Much of the storage being added now is for planned power plant optimization. It has little to nothing to do with the grid," Bakke said. "A lot of the planned hybrids today are around plant optimization, not grid optimization." Storage is also being built to provide ancillary services, something else the renewable integration study did not cover, he said.

Bakke said the storage phase of the RIIA only sought "general truths" about its role in enabling renewable growth and was not designed to favor transmission buildout.

"There is a saturation point after which incremental storage isn't helpful anymore and the effective load-carrying capability of renewables doesn't increase," MISO Policy Studies Senior Engineer Nihal Mohan said. "The results somewhat surprised us. ... If we keep on adding more and more storage on the system, we start to see a decline of ELCC on the system."

Mohan said CAISO has documented a similar trend of diminishing returns of storage after a certain point.

MISO also found that storage devices are more helpful when they are placed next to renewable generation, not load centers.

"When you co-locate storage at generation, it's kind of like you're putting a little reservoir near your generation. If you pair storage near the load — if you do not try to solve the transmission issue — there is still renewable curtailment," Tsai said.

The results are the final leg of the yearslong RIIA. Bakke said MISO's next order of business on the study is to summarize all study findings into a comprehensive report for stakeholders. He said the report should be completed by the first quarter of 2021. ■

DTE Energy to Cleave Pipeline Business

By Amanda Durish Cook

DTE Energy backed away from its pipeline business last week, announcing that it will spin off its non-utility natural gas pipeline, gathering and storage business.

The transaction will have the company shedding *DTE Midstream* and becoming a pure-play electric and natural gas utility. Midstream is set to carve out its own Detroit headquarters and become an independent and publicly traded company by mid-2021. DTE shareholders will retain their shares and receive *pro rata* shares of the new Midstream company.

DTE said the move will not negatively affect rates, customers or utility operations. CEO Jerry Norcia said the Midstream spinoff announcement "follows a thorough review with our board to identify opportunities to optimize our portfolio and maximize shareholder value."

"We recognize that this comes not long after our significant acquisition of assets in the Haynesville [Shale] basin," Norcia said during the company's third-quarter earnings call Oct. 27. "Through 2019, while business mix discussions were still ongoing, we continued to pursue an aggressive value creation agenda for Midstream, which yielded the Haynesville acquisition. … Because this acquisition and the balance of the Midstream portfolio continues to perform exceedingly well … and thrive on its own, it crystallized our path to pivot to a high growth pure-play utility with the spin of a well run Midstream company. We believe this strategy will unlock significant value for our shareholders."

Current Midstream President and COO David Slater is set to become CEO of the standalone company.

After the Midstream transaction, DTE will receive about 90% of its operating earnings from its core utility business versus the 70% it receives today.

Midstream owns approximately 2,350 miles of pipeline and operates 91 Bcf of gas storage capacity. DTE acquired most of the network in $1.3 billion and $2.5 billion transactions in 2016 and 2019 respectively. When the deal is complete DTE estimates it will generate 90% of its operating earnings from its utility business versus the current 70% operating earnings from its core utility.

"As most of you know, my background includes a substantial amount of time in the gas industry, including my involvement in development of our Midstream business. The team and I have dedicated a significant amount of time and energy creating a Midstream business at DTE that is recognized as one of the best in the country. So, you can imagine how important this decision is to our team and me. After careful consideration and review with our board, I am confident that the separation is the best way to allow the Midstream business and its team to achieve their full potential and to enhance overall value for our shareholders," Norcia said.

DTE estimates Midstream will earn $700 million before taxes in 2020.

The company reported third-quarter earnings of $476 million ($2.46/share), compared with $319 million ($1.73/share) in 2019. It said earnings were up because of higher year-over-year residential sales, higher rates and warmer weather. The earnings report represents a turnaround from first-quarter earnings, when DTE contemplated shaving millions from operations and maintenance expenses to offset drooping sales. (See *DTE to Cut Spending in Response to Pandemic*.)

"I want to thank all the leaders and our 10,000 employees of DTE for creating this tremendous success in a year of great turmoil and uncertainty," Norcia said. "We are firing on all cylinders, keeping our people safe and delivering for our customers, communities and investors. It is truly remarkable and certainly a reflection of the grit and determination of the great people of DTE."

Norcia said DTE plans to invest about $14 billion in its electric utility over the next five years, some of that in renewable generation. He noted DTE's goal of achieving net-zero carbon emissions by 2050. For that to happen, he said DTE needs to double renewable capacity by 2024 and quadruple it by 2040. ■

| DTE Midstream

MISO News

FERC OKs More Rigorous MISO Capacity Requirements

By Amanda Durish Cook

Conventional capacity resources in MISO will now have to prove full deliverability before collecting maximum capacity credits, FERC said last week.

The commission on Oct. 27 approved the RTO's proposal to require capacity resources to demonstrate deliverability through firm transmission service up to installed capacity (ICAP) levels before they can convert their entire unforced capacity (UCAP) into zonal resource credits (*ER20-1942*).

MISO said procuring firm transmission remains optional for capacity resources, provided that they are comfortable with settling for fewer capacity credits based on their partial ability to deliver. The RTO said it plans to prorate credits. Staff have previously acknowledged that it may be expensive for some resources to secure firm transmission service up to their installed capacity levels.

The RTO used to allow capacity resources to demonstrate full deliverability based on UCAP levels — something its Independent Market Monitor has long called inconsistent with the assumptions used in the grid operator's loss-of-load expectation (LOLE) study, which assumes that all capacity resources are fully deliverable.

Before, MISO's Tariff required capacity resources to demonstrate capacity deliverability by having network resource interconnection service, which stipulates that the entire ICAP of the resources must be deliverable. However, the Tariff also allowed resources to demonstrate deliverability by securing energy resource interconnection service and procuring firm transmission service up to their UCAP levels, which tend to be about 5 to 10% below full ICAP levels.

FERC agreed that the second option needed to be eliminated for the sake of reliability and accurate reserve margins.

"MISO has demonstrated a disparity between its LOLE study assumptions and the deliverability requirements associated with conventional capacity resources used to satisfy MISO's reserve requirements," the commission said. "As MISO explains, the LOLE analysis,

| © RTO Insider

and therefore the resultant reserve margin and reserve requirements, assumes that a conventional capacity resource can deliver its full installed capacity level of output when it is online. Therefore, we find reasonable MISO's proposal to require all conventional capacity resources that seek to participate in MISO's resource adequacy construct at their full unforced capacity levels to demonstrate deliverability up to their installed capacity levels. In doing so, MISO's proposal will provide certainty that MISO's reserve requirements are satisfied by fully deliverable planning resources, thereby ensuring that MISO meets its reliability needs." ■

MISO News

MISO, SPP Heads Present Unified Front on Seams

By Amanda Durish Cook

The heads of MISO and SPP stood on common ground to discuss seams issues during last week's Organization of MISO States' annual meeting.

The CEOs' unified front during the virtual conference Thursday was a striking change from the executives' past reticence on seams matters.

MISO CEO John Bear acknowledged that both RTOs are "struggling" with their renewables-packed interconnection queues.

"We've really built our systems out from our footprint perspective," he said, explaining that MISO and SPP have developed renewable generation near the seams, sometimes disregarding the congestion the projects can cause on each other's systems. He said in some cases, seams congestion has been neglected to the point that an interconnecting generator is "looking over a cliff" of interconnection expenses.

Bear said he and SPP CEO Barbara Sugg agreed that they needed to perform studies on the most congested areas.

The RTOs announced in September that they will partner on a special study focused on transmission projects that can bring more of the interconnection queues' renewable generation online. (See *MISO, SPP to Conduct Targeted Transmission Study*.)

"Look, we're fighting the same battles," Sugg said. "And I think the only way you're going to get a little is to give a little. We're 100% confident we're going to produce some really good results. We do share some of the very same pain points."

Sugg said cost-allocation discussions are not atop the agenda as the RTOs probe possible cross-border interconnection solutions.

"If somebody wants to talk to us about cost allocation in April, we won't talk about it," Sugg said, noting that it's important to keep potential bickering over costs out of an initial search for helpful projects.

"Look, we're going to have our differences in the future, but I think we'll be able to keep it out of FERC. I'm optimistic," she said.

Bear said that MISO-SPP relations have improved by "assuming noble intent on the other side" and having empathy for each other's challenges.

"At the end of the day, we are businesses competing with each other, but there's value in being partners," Sugg said.

Bear said seams management has long been MISO's *modus operandi*. When it began its energy market in 2004, MISO had to accommodate PJM member Commonwealth Edison in Chicago, which became an island within MISO's footprint.

"We've had to learn about seams very fast and furiously," he said.

Sugg said that as the two RTOs expand their footprints, seams arrangements must adjust with every new membership.

"Growth is a fantastic thing ... but it definitely makes the seams discussions continue to evolve. It definitely is an ongoing challenge, but one that is worth every minute of effort," she said. There's a better appreciation today among regulators of the energy markets' complexity, she continued.

Sugg said wind is poised to beat out coal this year as SPP's most used fuel source, a milestone that will come earlier than expected.

"There are so many wind-rich areas in SPP and such clamoring ... for energy produced from a renewable source," she said, noting a "robust transmission system" will be necessary to support the demand for renewables.

Bear said MISO's own ballooning renewable portfolio has prompted a rethink of its current resource adequacy construct that focuses on a summer peak. Bear said the RTO has a significant loss-of-load risk in some hours in shoulder periods.

"[It's] so we don't kid ourselves that we're reliable in every season, even though some hours might go unserved," he said.

Sugg predicted FERC Order 2222 — which directs RTOs and ISOs to develop participation models for distributed energy resource aggregations — will have a "humungous" effect on grid operators. (See *FERC Opens RTO Markets to DER Aggregation*.)

"It's going to have tremendous impact on us and change what enters the market," she said. ■

MISO CEO John Bear | *OMS*

MISO News

Entergy, in Eye of the Storms, Beats Expectations

By Tom Kleckner

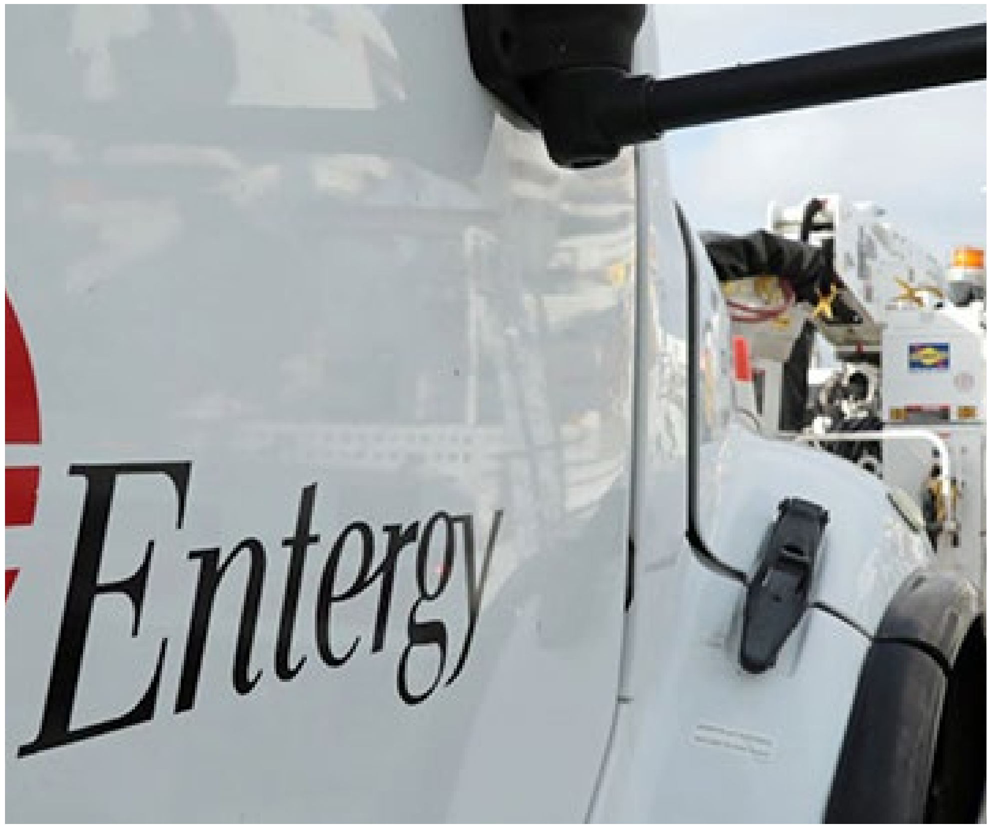
Entergy held its third-quarter earnings call with financial analysts Wednesday as yet another hurricane, the fifth to hit Louisiana this season, bore down on the state.

"We've activated our storm response plan, and we are fully prepared and ready to respond," Entergy CEO Leo Denault told analysts. "We've had a record-breaking storm season with back-to-back hurricanes hitting our service area. Yet no matter what 2020 threw at us, we remain steadfast in delivering on our commitments to our customers, our communities, our employees and our owners."

Hurricane Zeta made landfall later that evening, ripping through Entergy's New Orleans hometown with 110 mph winds. The most powerful hurricane to hit the U.S. this late in the year since 1899, Zeta knocked out power to more than 480,000 customers. By Monday morning, more than *64,000* were still without service, with some facing prospects of a full week without power.

Zeta followed Laura in August and Delta in October, both of which caused significant damage west of New Orleans. Aided by mutual assistance partners, Entergy deployed 12,000 workers after Delta to restore most of the nearly 500,000 outages in five days.

"We showed why we are best-in-class in storm response as we successfully managed to back-to-back major hurricanes all amid a global pandemic. That's what we prepare for, and that's what we do," Denault said. "We can control what we can control. We can't control the public health crisis, so we're going to control what we can control."



Entergy service trucks line up in preparation for restoration work. | *Entergy*

Entergy *reported* third-quarter earnings of $521 million ($2.59/share), as compared to 2019's third quarter of $365 million ($1.82/share). That exceeded analysts' expectations of $2.42/share, according to Zacks Information Research.

Denault said the results "amid these extraordinary times" demonstrated Entergy's progress in building a "simpler, stronger and more resilient company."

Entergy's share price lost traction during the week, as did the rest of the broader market. Shares closed Friday at $101.22, down 5.8% following the earnings announcement. ■

MISO News

Xcel Beats Expectations, Hypes EVs

Xcel Energy on Thursday *reported* third-quarter earnings of $603 million ($1.14/share), beating Zacks Investment Research's consensus expectation by 7 cents. A year ago, Xcel's earnings were $527 million ($1.01/share).

| *Xcel Energy Center*

The company narrowed its 2020 earnings guidance to $2.75 to $2.81/share and initiated its guidance for 2021 at $2.90 to $3/share.

The Minneapolis-based company said it intends to invest $22.6 billion in base capital, including an incremental $1.4 billion addressing COVID-19's economic effects in Minnesota. Xcel has proposed spending money on the grid, solar facilities and repowering aging wind farms, which it said would create 5,000 jobs and add 5 GW to its renewable portfolio.

Xcel also outlined a 10-year vision to power 1.5 million electric vehicles in its service territory by 2030. The company already installs home chargers for customers but wants to see fast-charging stations expanded along highways and other travel corridors.

"I'm particularly excited about EVs. … The variable cost of an EV is significantly below that of a gasoline[-fueled]" vehicle, CEO Ben Fowke told financial analysts, with the cost of EV charging equivalent to 60-cents/gallon gasoline. "So while EVs are expensive today, we think that cost comes down. The key to me is to get these stations built. … One of the biggest barriers to purchasing an EV is range anxiety."

Xcel's share price closed Friday at $70.03, having lost 23 cents after the earnings release. ■

— Tom Kleckner

NYISO News

Study: Storage Can Replace 53% of LIPA Peakers by 2030

LIPA Disputes Findings

By Michael Kuser

The Long Island Power Authority (LIPA) could replace more than half of its aging and rarely used fossil-fueled peaker plants with energy storage by 2030, saving ratepayers almost $400 million, according to a *study* released last week.

The report by consulting firm Strategen, prepared for the New York Battery and Energy Storage Technology Consortium (NY-BEST), said "it is feasible and cost-effective" to replace 1,116 MW of peakers by 2023 and more than 2,300 MW by 2030. It said LIPA frequently dispatches the 4,357 MW of peaker units on the island uneconomically and for reasons other than meeting peak-load needs.

In addition to saving customers more than $390 million in net present value over the next 10 years — about $360 per household — the study says swapping peakers with batteries would significantly reduce harmful air pollutants.

"The whole framing of this is that New York has the goal of getting to zero emissions by 2040 ... so we need to start on that path with what we can do now," Edward Burgess, lead author of the study and a senior director at *Strategen*, told *RTO Insider*.

Strategen, based in Berkeley, Calif., estimates that the peaker fleet is costing Long Island ratepayers approximately $473 million annually just for capacity — three times the market rate for capacity resources cleared through NYISO's competitive markets — and that if it is not replaced, the cost could increase to $716 million by 2030. (The study identifies as peakers those plants with an annual capacity factor of 15% or less; it says about 3,053 MW of the capacity operated 10% or less of the time, while 36 units (1,249 MW) ran less than 1% of the time in 2019.)

A 15-year power service agreement (*PSA*) between LIPA and National Grid that runs to 2028 accounts for the bulk of these costs. The PSA is for 3,634 MW, 90% of which are for peaking plants.

LIPA spokeswoman Jen Hayen told *RTO Insider* that LIPA will be issuing a request for storage proposals in the next several months that may result in the replacement of certain Long Island peaker or steam plants and will evaluate the proposals it receives compared to the costs of the existing units.

"LIPA has already announced the retirement of 68 MW of peaker plants in 2020 and 2021 and has an ongoing study for the retirement of an additional 400 to 600 MW of steam and peaker plants in 2022. We anticipate additional retirements in 2024 and beyond," Hayen said.

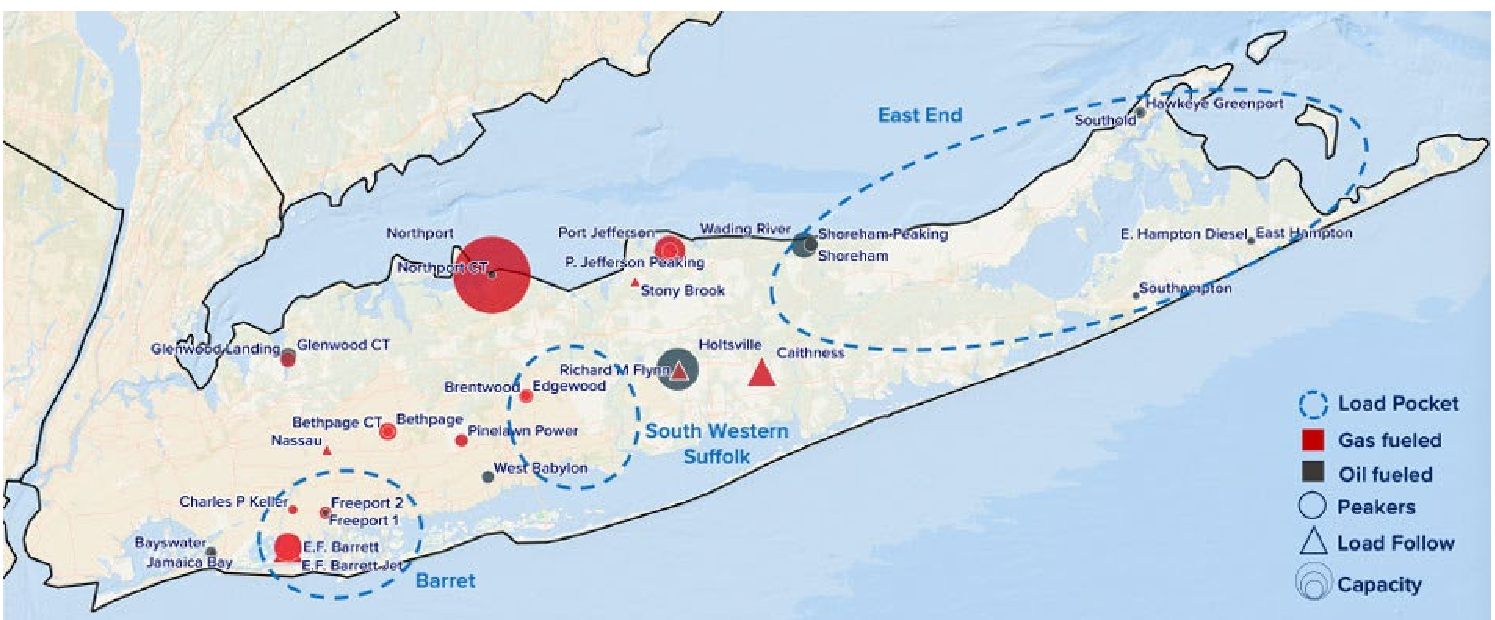
She challenged the study's savings estimates, saying they "are higher than we have experienced in either deploying storage or retiring existing plants."

"In classifying low-usage steam plants as 'peaking plants,' the study overstates the potential savings in fixed costs, much of which are prior capital costs that must be paid to the plant owner at the time of retirement," Hayen said. "Moreover, the study assumes that future storage discharge requirements can be determined from past peaker operation, which does not reflect the significant system changes that will be occurring."

Uneconomic Dispatch?

The study's claim that the peakers are frequently dispatched when they are not economic is based on the 2019 NYISO State of the Market *report* by the ISO's Market Monitoring Unit, Potomac Economics. It said out-of-merit "dispatch was frequently used to manage 69-kV constraints and voltage constraints (i.e., transient voltage recovery requirement on the East End of Long Island)."

In addition to using peakers to resolve local transmission problems, LIPA generally does not coordinate their dispatch with NYISO, so the actions are not optimized through the ISO's day-ahead and real-time market software, the study said. The result is often



LIPA's fossil fuel peaker capacity could be replaced by a mixture of storage, offshore wind, energy efficiency and rooftop solar. | *Strategen*

NYISO News

depressed locational-based marginal prices that send inaccurate price signals for potential future investment and require millions of dollars in uplift charges.

"The proportion of hours where out-of-merit actions were taken to resolve congestion issues (versus times when the market was used to resolve these) were quite significant throughout Long Island and are more pronounced in certain locations," the study said. "For example, in the Brentwood area, 99% of congested hours in 2019 were managed through out-of-merit actions rather than through the [day-ahead] and [real time] markets."

The MMU's 2019 report also noted that NYISO has said that issues frequently arise because of lack of coordination between the ISO and LIPA regarding the scheduling of phase angle regulators to manage congestion. Under state law, LIPA is generally exempt from the New York Public Service Commission's jurisdiction.

An Evolving Grid

The study notes that the percentage of the peaker fleet on Long Island (Zone K) needed to meet peaking needs has declined in recent years, from 71% in 2016, to 67% in 2017 and 64% in 2018. Whether that decline continues, Burgess said, will depend not only on the peakers, "but also [on] what's happening on the load side."

"On the one hand, maybe we have increasing demand from electrification, but on the other hand, maybe there's more distributed solar or energy efficiency," he said.

Other generation on the system is also a factor, he continued. "Are we using more of the recently installed combined cycle units because gas is cheap? That certainly would be an interesting thing to look into further and see how those trends have gone over a longer period of time," Burgess said.

The state's Climate Leadership and Community Protection Act (CLCPA) calls for at least 9 GW of offshore wind energy by 2035, and 6 GW of that will likely interconnect onto Long Island by 2030. The CLCPA also targets 6 GW of distributed solar generation by 2025, 3 GW of energy storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025.

The study mentions that the iconic Ravenswood peaker plant on the East River in New York City is being converted to a 318-MW energy storage facility.

Asked why such conversions aren't happening on Long Island, Burgess said, "Definitely there's a need for local generation capacity in New York City [Zone J]. There's also a need for generation on Long Island too. I believe part of the rationale for that is that [at Ravenswood], we have a site with an interconnection and it's all ready to go, and New York City is even more constrained in that sense than Long Island is."

One of the values of storage is its ability to perform functions in addition to substituting for generation, he noted. "Storage can also be a load; it can absorb energy," Burgess said. "Perhaps down the road when we have a lot more renewables on the system that's going to be a necessary function too, if you have oversupply of wind or solar at a certain time. And there's all the different ancillary services it could provide too: balancing functions [and] ramping up and down in very quick succession."

"On the one hand, maybe we have increasing demand from electrification, but on the other hand, maybe there's more distributed solar or energy efficiency."

—Edward Burgess, lead author of the study and a senior director at Strategen

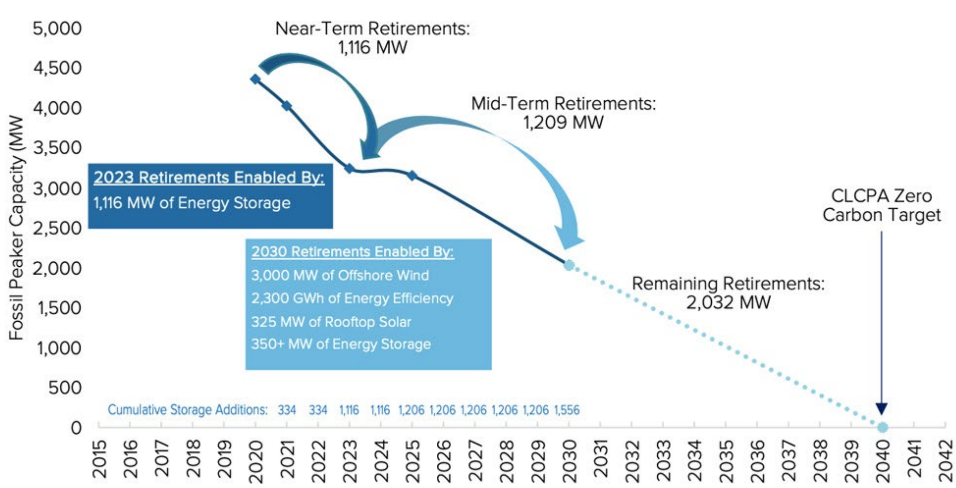
Of the 2,300 MW of fossil peaker plant replacements, 334 MW could be retired and replaced immediately, and in the East End of Long Island, there is a near-term opportunity for up to 90 MW of fossil peakers to be displaced with storage, the study said.

Burgess said some peakers will likely retire because of the state Department of Environmental Conservation's (DEC) regulation limiting nitrogen oxides (NO_x) emissions from simple cycle combustion turbines. The department required all impacted plant owners to file compliance plans by March 2, 2020. The phased approach goes into effect May 1, 2023, and limits emissions to 100 ppm, dropping two years later to 25 ppm for units using gaseous fuels and 42 ppm for units burning liquid fuels. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

Because of "the NO_x regulations that the DEC put out … some of these plants without the pollution controls will have to either be making retrofits or retiring," Burgess said. "We've also got decisions that LIPA is going to have to make around contracts and the current power supply agreement that they have with National Grid. ... There are provisions that would allow them to ramp down a portion of that.

"And there are a lot of inefficiencies that we're seeing here in how some of these plants are being operated. There are some economic benefits to be gained, so that's another driving factor, along with the environmental," he said.

Replacing peakers with storage will eliminate 2.65 million metric tons of CO_2, 1,910 tons of NO_x and 639 tons of SO_2 of emissions annually, resulting in societal benefits of $163 million annually through fewer pollution-related deaths and hospital visits, according to the study. ■



LIPA's fossil fuel peaker capacity could be replaced by a mixture of storage, offshore wind, energy efficiency and rooftop solar. | *Strategen*

NYISO Management Committee Briefs

Fix Endorsed on Demand Curve Reset

The NYISO Management Committee on Wednesday endorsed a technical fix to the 2017-2021 capacity demand curve reset (DCR) to address an error in the model used to estimate net energy and ancillary services (EAS) revenues for the hypothetical peaking plant.

The problem resulted from a misalignment of natural gas prices. The model assumed that index prices published by S&P Global represented the "trade day" — the day before generators take delivery and use the gas to produce electricity. In fact, the data actually represent the "flow day" prices.

The error was discovered during work on the net EAS model for the 2021-2025 DCR, and the change will apply to that period as well. (See NYISO Management Committee Briefs: Sept. 23, 2020.)

NYISO already submitted the change to FERC, which approved it on Oct. 22 (ER21-130). "We have implemented the revised reference prices into the capacity market [and] spot market auctions," Vice President of Market Operations Robb Pike said.

Pike said the ISO would submit an informational filing to FERC to provide notice of the MC's concurrence with the previously filed revisions.

The 2017-2021 DCR includes the capacity demand curves for the 2017/18 through 2020/21 capability years (May 1, 2017, through April 30, 2021).

2020 Reliability Needs Assessment OK'd

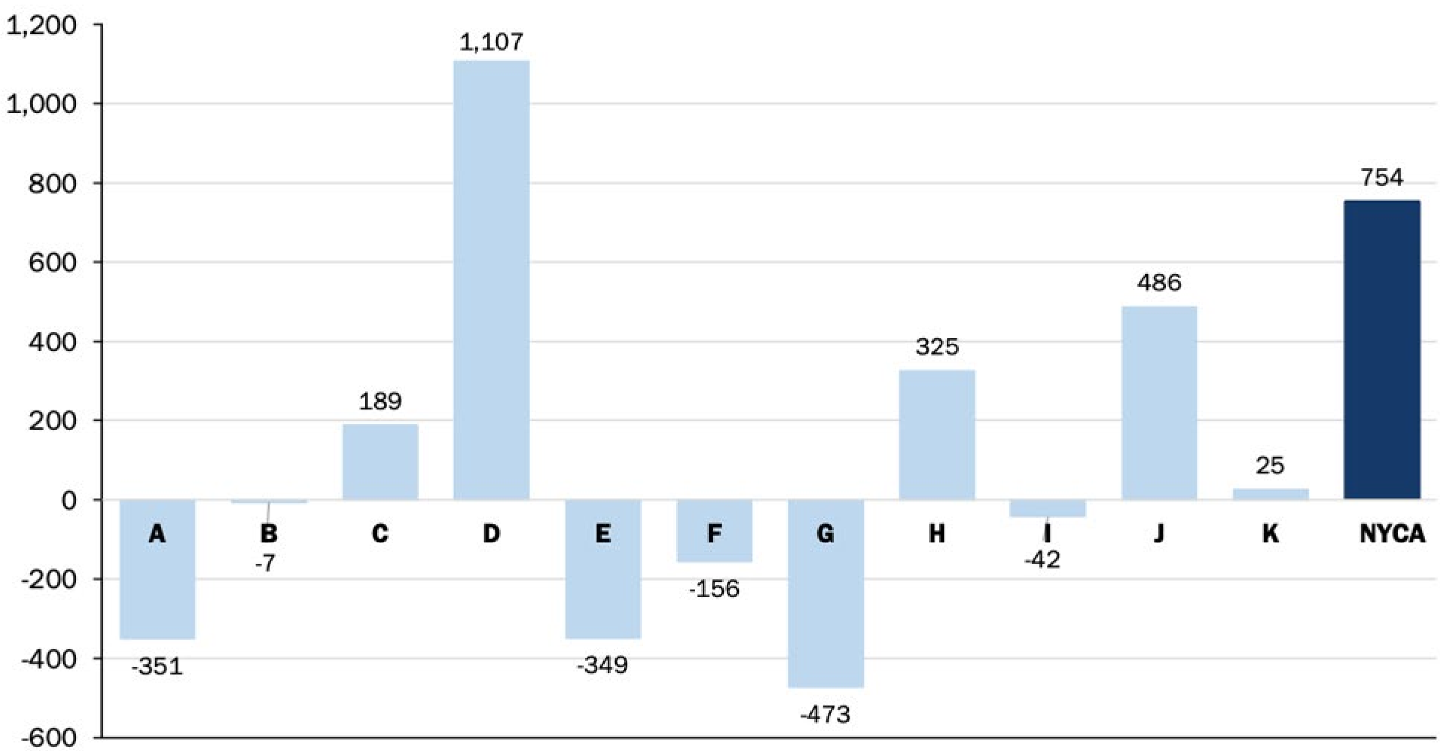
The MC unanimously approved the 2020 Reliability Needs Assessment (RNA), which cut the peak load forecasts for 2020-2028 by as much as 467 MW from the 2018 RNA. If the Board of Directors approves the revisions in November, NYISO will file the changes with FERC.

Laura Popa, manager of resource planning, presented the 2020 RNA, which examines needs over the coming 10 years. The presentation included a transmission analysis supplied by Keith Burrell, manager of transmission studies.

Pallas LeeVanSchaick of Potomac Economics, the ISO's Market Monitoring Unit, presented comments on the RNA and said the MMU found a number of areas where the reliability needs identified by the RNA are in part driven by gaps in the market design, where it fails to provide incentives for resources.

Some key findings that the MMU focused on included a number of base case transmission violations from 2024 to 2030 in New York City driven by impending peaker retirements and load growth, he said. The state Department of Environmental Conservation last year adopted a regulation to limit nitrogen oxides (NO_x) emissions from simple cycle combustion turbines, or peaking units, and required all impacted plant owners to file compliance plans by March 2. (See NY DEC Kicks off Peaker Emissions Limits Hearings.)

The RNA found transmission security violations on Consolidated Edison's non-bulk power transmission facilities system in the Astoria East/Corona as well as Greenwood/Fox Hills load pockets, rising to 180 MW in 2030 for the former and 370 MW for the latter.



NYISO Gold Book baseline energy forecast growth rates, 2020 to 2030, used in the current Reliability Needs Assessment | *NYISO*

NYISO News

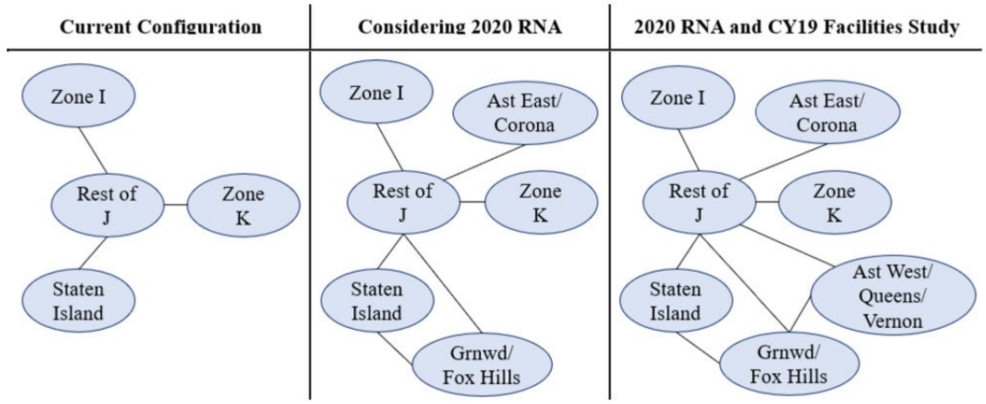
It "also found transmission security violations on Con Edison's bulk system, and the deficiency there rises to 1,075 MW by 2030," LeeVanSchaick said. "[The RNA] also found resource adequacy violations beginning in 2027, but it's notable that the compensatory megawatts needed to resolve those are much lower than for the transmission security violations ... being only 350 MW by 2030."

The two significant takeaways are Astoria East/Corona and Greenwood/Fox Hills, as well as the "big difference" between the compensatory megawatts needed in the transmission security analysis versus those in the resource adequacy analysis, he said.

"This RNA reveals a number of ways in which the NYISO market design fails to reflect the value of resources that help satisfy transmission security needs, which may lead to [reliability-must-run] contracts and other regulated transmission investment. The first recommendation that would help to align market signals with the reliability value of resources is better reserve market pricing in New York City," LeeVanSchaick said.

The second issue is lining up the capacity accreditation with the reliability value of resources in NYISO planning studies, particularly for the large units and special-case resources, LeeVanSchaick said. Finally, the RNA is another piece of information that supports enhancing locational capacity pricing with the "C-LMP" framework, which would allow the ISO to set different prices for different areas and, in turn, for more cost-effective capacity to meet reliability needs, he said.

"If you do those things, it's much less likely that you'd have to make any further out-of-market investment," LeeVanSchaick said.



The MMU says the 2020 RNA and related Class Year 2019 studies imply the value of capacity varies widely and suggested that a C-LMP can be implemented to align capacity pricing with reliability value. | *Potomac Economics*

NYISO will seek updates to local transmission owner plans and other resource and load changes in December and determine in January whether the needs should be adjusted and solutions solicited to the remaining needs.

2021 Budget Approved

The MC also approved a draft *budget* for 2021, which will go before the board for final approval in November.

Alan Ackerman of Customized Energy Solutions, chair of the Budget and Priorities Working Group, *presented* the draft budget, which was unchanged from the draft stakeholders reviewed last month.

For the second year in a row, NYISO is proposing a decrease to the budgeted revenue requirement, with the draft budget allocating $167.4 million across a forecast of 147.3 million MWh, for a Rate Schedule 1 charge of $1.137/MWh, down from the 2020 budget of $168 million allocated across 154.3 million MWh ($1.089/MWh).

Wentlent Elected 2021 Vice Chair

The MC elected Christ Wentlent to serve as its vice chair for 2021, beginning in December.

Wentlent represents the Municipal Electric Utilities Association and New York Municipal Power Agency as liaison to both NYISO and the New York State Reliability Council.

He was unable to attend the meeting, but he sent a message read by Chair Jane Quin. "We all know our energy market is at a major transition point, and I would be honored to assist the NYISO and its stakeholders with that transition," he said. ■

— Michael Kuser

NYISO News

NYISO Reviews Fuel Security, Mitigation Project

Fuel and Energy Security OK for Now

NYISO told stakeholders last week that its fuel and energy security (FES) *metrics* remain "well aligned" with the assumptions of Analysis Group's November 2019 *study*, which concluded that the state's grid is "currently well equipped to maintain reliability in the winter, even under adverse winter system conditions."

Although the report concluded "only fairly severe and relatively low probability conditions or events would create meaningful reliability challenges," it said the ISO should continue monitoring because of the transition of its resource fleet and the increasing reliance on natural gas and renewables.

In April, NYISO pledged to update the metrics at least twice a year and said the study will be "refreshed" if the ISO observes large deviations between actual conditions and the conditions assessed in the study. A refresh also could result from large differences between the study's assumptions and actual conditions that could adversely affect reliability. (See *NYISO Launches Fuel Security Effort*.)

The ISO uses 23 metrics to monitor fuel security, including the deployment of new renewable and clean energy resources; the impact of the state Department of Environmental Conservation peaker rule; gas-only generator outages because of lack of fuel; and the status of transmission upgrades such as the AC Transmission Projects and Western NY Public Policy Transmission Need.

"We were aiming to enhance monitoring by adding some elements related to fuel security to both the Winter Capacity Assessment and the cold-weather operations presentations, those occurring in the fall and the spring," market design specialist Amanda Myott told the Installed Capacity/Market Issues Working Group.

The ISO also is working to improve the accuracy of its generator fuel and emissions reporting (GFER) surveys, which inform internal FES assessments.

The fuel security monitoring "is focused on severe cold-weather conditions and being able to meet winter peaks in those conditions," Vice President of Operations Wes Yeomans said.

On compensating for the intermittency of renewable resources, Yeomans said, "At other times of the year, we might have a duration of low wind or clouds; we are certainly aware of that and have other processes we're trying to enhance with market designs and even some good work setting up the [installed reserve margin] with" the New York State Reliability Council.

In response to a recommendation that the ISO consider comparing actual conditions and operating experience to the conditions assumed in the FES study, Yeomans noted that winter 2019/20 was "extremely mild."

"But if there is a cold snap this upcoming winter, it will be very important to look at what we assumed about gas availability for the generator fleet and the actual availability experienced," he added.

CMR Project Treads Water

NYISO is pausing its Comprehensive Mitigation Review (CMR) project until it receives further clarity from FERC, which rejected the ISO's proposal to make it easier for public policy resources to clear its capacity market, Michael DeSocio, director for market design, said in an *update*.

The project's objective is to modify the capacity market framework while preserving competitive signals and facilitating the state's ambitious clean energy goals. CMR efforts this year included the ISO's proposed renewable exemption limit and changes to the Part A test for exempting resources from market mitigation.

In July, FERC approved the renewable exemption limit formula for calculating a megawatt cap of renewable resources exempt from buyer-side market power mitigation (BSM) specific to each mitigated zone. (See *NYISO BSM Mitigation Ruling Sparks Glick Rebuke*.)

But the commission rejected the Part A changes on Sept. 4, prompting a dissent from Commissioner Richard Glick and an Oct. 5 rehearing *request* by the ISO (ER20-1718-002). (See *FERC Rejects NYISO Bid to Aid Public Policy Resources*.) Rehearing requests were also filed by *Equinox*, *New York Transmission Owners* and *jointly* by the New York State Energy Research and Development Authority and Public Service Commission.

"The ISO still thinks that the proposal is an excellent one that makes a whole lot of sense," DeSocio said. "FERC unfortunately didn't see it exactly the same way."

The ISO's BSM rules require new ICAP resources in New York City and zones G-I to offer at or above the default offer floor. To win an exemption from mitigation, a new entrant must pass one of two exemption tests. Part A allows exemptions if the forecast of capacity prices in the first year of a new entrant's operation is higher than the default offer floor. Part B permits exemptions if the forecast of capacity prices in the first three years of a new entrant's operation is higher than its net cost of new entry (CONE).

DeSocio said ISO officials are considering a suite of options, the first being contractual models such as CAISO's, with an energy-only market and fixed resource requirement.

The second option is enhancements to the capacity market such as to BSM, available capacity transfers and a future clean capacity requirement. The third option is a redesign of the capacity market, with possibilities such as a "multiple value pricing" model that co-optimizes over several variables (e.g. specific to resource type, zero-carbon resources, etc.) and a Forward Clean Energy Market to procure a certain percentage of generation from qualifying renewable resources.

The combination of the renewable exemption limit and the BSM proposals addressed many of the concepts being considered in the proposal for available capacity transfer (ACT) — expanding the use of the renewable exemption bank — and CRIS+, the pairing of transferable capacity resource interconnection service (CRIS) rights with an existing resource's BSM exemption.

"We're recommending to put [ACT and CRIS+] on the shelf until we get clarity on the Part A revisions that we filed earlier this year," DeSocio said.

In the meantime, the ISO wants stakeholder feedback on capacity market changes and any other ideas before moving into 2021, he said.

"As we add more renewable resources and more limited-duration resources in the future, that will change how we approach reliability, and that does have an impact on the role of the capacity market," DeSocio said.

The ISO will likely be more focused on BSM and how that impacts state policies and the design of the capacity market, and how the capacity market supports resource adequacy, he said.

"It's a broad conversation, and if folks have ideas on how to structure that, I would certainly be willing to listen, because these markets are pretty complex, and as you tug on one area, it affects another area," DeSocio said. ■

— Michael Kuser

Overheard at ACE NY Fall Conference 2020

Actor and anti-fracking activist Mark Ruffalo and former EPA Administrator Gina McCarthy, now CEO of the Natural Resources Defense Council, headlined the Alliance for Clean Energy New York's (ACE NY) annual Fall Conference Wednesday. Here are some highlights of what we heard.

Taking Action

In her keynote address, McCarthy said the climate battle being waged in the country is "a fight for our lives" and the future of the planet. She said people concerned with the environment need to raise their voices together to demand action.

The good news, McCarthy said, is that solutions exist to deal with climate issues, and one of the biggest answers to the problem is clean energy. She said the conversation around clean energy needs to continue and expand because initiatives are taking off at a greater pace at the state and local level because of the economic, health and quality of life benefits they provide.

McCarthy said she is particularly excited by the opportunities for the development of offshore wind on the East Coast, and a next step in the green energy revolution is to have federal leadership that will act on a national level.

"We need to turbo-charge the transition to clean energy nationwide," McCarthy said. "And while there's no substitute for federal leadership, there is no way that any of us are going to wait for Washington to wake up."

With the current political climate, McCarthy said now is not the time to be "morose" or to sit and wait for things to happen regarding clean energy. She said there needs to be a "doubling-down effort" on building local and grassroots momentum across the country to "tip the scales" away from fossil fuels.

McCarthy said what has made New York a leader on climate initiatives was the passage of the Climate Leadership and Community Preservation Act (*CLCPA*) in July 2019. The CLCPA requires that 70% of electricity come from renewable resources by 2030 and that electricity generation be 100% carbon-free by 2040. Clean energy targets include deploying at least 9 GW of offshore wind energy by 2035, doubling distributed solar generation to 6 GW by 2025, deploying 3 GW of energy storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025. (See *Cuomo Sets New York's Green Goals for 2020*.)

Actor Mark Ruffalo speaks during the ACE NY fall conference. | *ACE NY*

The time for action and implementation of the CLCPA is now, putting it to work to transform the transportation sector and the power sector and modernize the electric grid, McCarthy said, adding that action on clean energy means many well paying jobs will be created.

"Progress is happening here, and if you can do it and show the way, then progress will happen all across the nation," McCarthy said. "And it won't matter if it's red or purple or blue. Every state will want a piece of the action."

Hulk Talk Green New York

Ruffalo, the award-winning actor and a resident of New York, said he's been a longtime advocate for clean energy and addressing climate change as he spoke in a short video presented at the conference. He said ACE NY has been hard at work for years, helping the state adopt one of the most aggressive climate acts in the country.

The actor said ACE NY has embarked on an "ambitious" study of the transmission system to make sure it can handle all the renewable energy set to come online. He said the organization has played a leading role in making a clean energy future possible in the state and helping to reach the renewable energy generation goals laid out in the CLCPA.

New York has the chance to be "the greenest state in the nation," Ruffalo said.

"Trust me, I know a little bit about going green — dad joke," Ruffalo said, referencing his role as the Hulk in the Marvel Cinematic Universe franchise of superhero movies.

Building the Offshore Wind Industry in NY

In a discussion on building New York's offshore wind industry, Nathanael Greene, senior renewable energy advocate for NRDC, called for "rigorous pre- and post-construction monitoring" to protect wildlife and fish habitats, which he said the Department of the Interior's Bureau of Ocean Energy Management is not requiring.

"The data from good monitoring will tell us what needs to be protected and if the companies' mitigation measures are working. Ultimately, it makes protections more cost effective," he said. "But we can't do pre-construction monitoring and develop baselines after the fact. We need developers to step up and include detailed monitoring plans in their [construction and operations plans] until BOEM starts requiring them."

Greene also criticized FERC's buyer-side mitigation requirements, saying they are undermining New York's clean energy efforts. "And now some want to expand buyer-side management so that it's statewide, which would make a bad policy terrible," he said. "It's time we took seriously the alternatives to the capacity market and take steps necessary so that New York voters, our elected and appointed officials determine our resource adequacy, not the fossil fuel agenda of ideologues at FERC. The makeup of FERC may change following the election, but until the feds catch up with New York's climate leadership, we may have no choice but to take charge of our own power mix planning."

Adrienne Downey, principal engineer for offshore wind for the New York State Energy Research and Development Authority, said New York's pledge to build 9 GW of OSW, as well as the targets by neighboring states, have gotten the attention of Asian and European investors.

"We are seeding an incredible opportunity here. Right now, [for] the earliest projects, the lion's share of jobs are clearly in the construction and installation phase [and] in the operations and maintenance phase, which is 25 years.

"We want to expand that to see manufacturing start to happen. So, what we would anticipate is we'll start to see the components that are probably the most logistically flexible … so we might see towers [and] foundations. We're anxious to start seeing deeper manufacturing

NYISO News

come as we advance our target deeper toward 9 GW to things like blades. The holy grail would be full turbine assembly."

Dominik Schwegmann, head of offshore development for RWE Renewables Americas, said manufacturing will only come to the U.S. "if the offtake for these components is there; if the market has the size; if the project pipeline … is predictable and reliable for the manufacturers to say, 'Yes, I [will] invest [a] couple hundred million dollars and do investments in the training of the workforce. … The [U.S.] market has enough … potential to justify that, just as in Europe."

Joe Martens, director of the *New York Offshore Wind Alliance*, noted that the U.S. hasn't completed the permitting for any commercial-scale OSW yet.

"I think that once there is a clear signal from Washington, then I think we will see some significant investment in other components that right now are not manufactured in the U.S. come to the U.S. And that will be an exciting moment."

YIMBYs

ACE NY named *Win With Wind*, a group of private citizens on the South Fork of Long Island, winner of its 2020 Clean Energy Advocate award.

Martens said the group, which seeks to generate grassroots support for and combat misinformation against offshore wind, is "motivated by their simple and sincere desire to see their communities in the forefront of clean energy leadership."

"There is no place more vulnerable to climate change than Long Island," he added. "Rising sea levels and ocean acidification, in particular, are a direct and immediate threat."

Cate Rogers, a member of the group's steering committee, accepted the award. Rogers said she and another activist, Judith Hope, started the group in 2018 to counter disinformation on the South Fork Wind Farm, a 15-turbine project that Ørsted will build wind 35 miles off Montauk.

After organizing the group, Rogers said, she learned "that an overwhelming majority of people in our community supported the project and the transition to renewable energy. They just needed to be given the facts, have some questions answered and understand that we have shovel-ready solutions at hand. … But without a place to gather, a group with which to connect, they could remain the silent majority and, even worse, fall victim to misinformation and scare tactics and take up the mantra we often hear: 'I support renewable energy, but not this project.'"


Gina McCarthy, NRDC | © *RTO Insider*

After the award presentation, ACE heard from Betta Broad, director of *New Yorkers for Clean Power*, which supports electrification and renewable generation. Broad said the group's goal is "creating more YIMBYs — that's 'Yes, in my backyard.'" ■

— Michael Yoder and Rich Heidorn Jr.

PJM News

Md., NC, Va. to Team up on Offshore Wind

States Seek Jobs, Economic Development Boost

By Rich Heidorn Jr.

The governors of Maryland, North Carolina and Virginia *said* Thursday they will collaborate to promote their states as a hub for the offshore wind industry.

The Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources (SMART-POWER) will seek to increase regulatory certainty, encourage manufacturing of components, reduce project costs through supply chain development and share best practices.

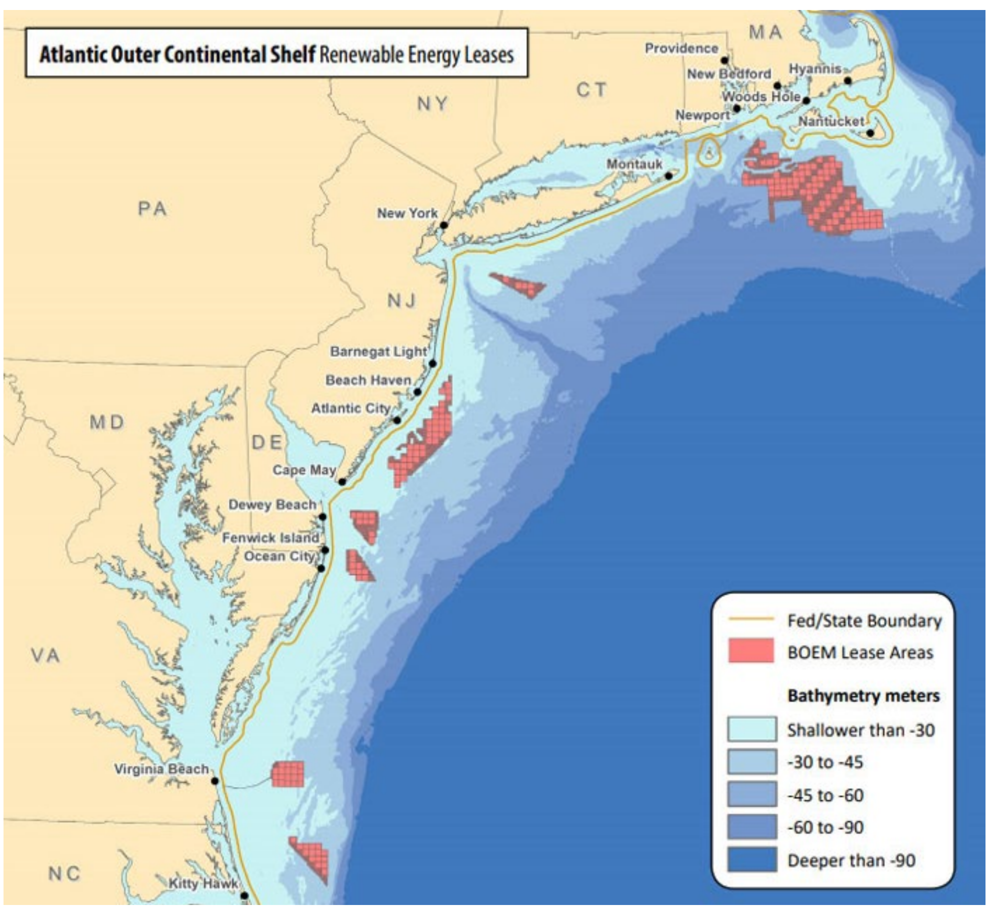
OSW can "drive economic development and job creation as well as reduce the emission of greenhouse gases and other harmful air pollutants," the group said in a press release, citing Department of Energy estimates that the Atlantic Coast OSW project pipeline could support 86,000 jobs, $57 billion in investments and generate up to $25 billion in economic output by 2030.

Virginia (5.2 GW) and Maryland (1.2 GW) have pledged to build 6.4 of the 29.1 GW in OSW capacity targeted by East Coast states.

North Carolina has not made any commitments, although it issued a *request for proposals* this summer for a supply chain and infrastructure assessment that will include identification of necessary port upgrades in Wilmington and Morehead City.

North Carolina's *Clean Energy Plan* notes that Avangrid Renewables is developing the *Kitty Hawk* Wind Energy Area, 24 nautical miles from Corolla, which the company says has capacity for 2.5 GW. The plan, issued in October 2019, followed Gov. Roy Cooper's (D) 2018 *executive order* calling for GHG reductions of 40% from 2005 levels by 2025.

Cooper said the three-state agreement "allows us to leverage our combined economic power and ideas to achieve cost-effective success."



PJM has five coastal states that could develop offshore wind: New Jersey, Delaware, Maryland, Virginia and North Carolina. | *BOEM*

Virginia Gov. Ralph Northam (D) said OSW will be "key to meeting the urgency of the climate crisis and achieving 100% clean energy by 2050."

The states' *memorandum of understanding* says they will coordinate to use their assets "such as deepwater ports and transportation infrastructure, top-tier universities and research institutions, and highly trained workforces to support the offshore wind industry and supply chain to efficiently develop along the Atlantic Coast."

The states will create a leadership team of representatives from each state that will meet at least quarterly and report to the governors annually on their "activities, progress and future strategies."

The MOU also says the states will seek to reduce administrative burdens on the industry "by clarifying, streamlining and aligning, where appropriate, state regulatory requirements" for construction of OSW projects.

They also will share best practices about regulatory processes, military compatibility, environmental protection, workforce training, public engagement, competing uses, and community and stakeholder interests, including those of fishermen and boaters.

The states also pledged to coordinate their communications with the U.S. departments of Commerce, Defense, Homeland Security and the Interior.

"An alliance between Maryland, North Carolina and Virginia balances offshore wind economic development more evenly across the East Coast," said Liz Burdock, CEO of the Business Network for Offshore Wind. "The market is now too dynamic and requires such large-scale collaboration that no one state should go it alone; regional cooperation is a must as the industry begins a multibillion dollar buildout over the next decade."

Laura Morton, the American Wind Energy Association's senior director of policy and regulatory affairs for OSW, praised the agreement.

"By adding multistate coordination to their individual efforts, the three states will be able to move forward more efficiently to develop their infrastructure and local supply chains to unleash this brand new American energy industry and the jobs and investments that come with it," she said. ■

FirstEnergy CEO Fired over Bribe Probe

Current President Strah Named Interim CEO

By Michael Yoder and Rich Heidorn Jr.

Former FirstEnergy CEO Charles Jones gives a shareholder address in 2018. | *FirstEnergy*

FirstEnergy announced late Thursday it had fired CEO Charles Jones and two other officials after an internal investigation determined they had violated the company's code of conduct in the alleged bribery scheme that resulted in the passage of Ohio House Bill 6.

In July, federal prosecutors alleged FirstEnergy spent $61 million in bribes, "dark money" campaign contributions and advertising to elect the speaker of the Ohio House of Representatives and allies in return for their support of HB6, which provided $1.5 billion in subsidies for the utility's struggling nuclear plants.

In a press release issued Thursday evening, company officials said the Independent Review Committee of the Board of Directors had announced the termination of Jones, along with two other executives: Dennis Chack, senior vice president of product development, marketing and branding; and Michael Dowling, senior vice president of external affairs.

Officials said an internal review related to "government investigations" determined the executives "violated certain FirstEnergy policies and its code of conduct."

Jones' firing was announced after the stock market closed and the guilty pleas earlier in the day of former FirstEnergy Solutions (FES) lobbyist Juan Cespedes, 41, and political strategist Jeff Longstreth, 44, who admitted to participating in a racketeering conspiracy.

FirstEnergy is alleged to have supported the election of former Ohio House Speaker Larry Householder (R) and his associates in a three-year scheme that resulted in the approval of zero-emission credits for FES' money-losing Perry and Davis-Besse nuclear plants.

Denied Wrongdoing

FirstEnergy no longer owns the nuclear plants, after FES emerged from bankruptcy in February as an independent company, Energy Harbor. But the affidavit that accompanied the criminal charges said that the CEO of "Company A" — as FirstEnergy was referred to in the document — was in regular contact with Householder. (See *Feds: FE Paid $61 Million in Bribes to Win Nuke Subsidy*.)

Jones, who had led FE since 2015, denied wrongdoing in a second-quarter earnings call, saying, "We let the merits of our arguments carry the day when we're operating in the political environment." (See *FirstEnergy, AEP CEOs Deny Wrongdoing*.)

Steven Strah, president of FirstEnergy, was appointed Thursday as FirstEnergy's acting CEO. Christopher Pappas, a member of the company's board, was named executive director.

"We as a board have strong confidence that this leadership transition, and Steve's appointment as acting CEO, will position FirstEnergy to move forward with positive momentum and drive long-term shareholder value creation," said Donald Misheff, non-executive chairman of FirstEnergy. "I look forward to working with Chris in his role as executive director to oversee the management team's execution of FirstEnergy's strategic initiatives, engage with the company's external stakeholders and support the development of enhanced controls and governance policies and procedures."

Strah was appointed FirstEnergy's president in May as part of the company's succession planning process, taking over the position from Jones. (See *Strah Named New President of FirstEnergy*.) Strah, who began his career with The Illuminating Company in 1984, previously served as regional president and vice president of distribution support of Ohio Edison and senior vice president at FirstEnergy Utilities.

"I'm excited for the opportunity to lead FirstEnergy, and I am deeply committed to the future of this company," Strah said. "I have seen firsthand the strong management team and deep bench of highly capable leaders across our organization, and I am confident in our ability to continue delivering value to our stakeholders as we remain intently focused on our business priorities through this transition and beyond."

According to a company biography, Jones began his career with Ohio Edison as a substation engineer in 1978 before being named president of Ohio Edison's Penn Power subsidiary in 1995. Jones would later go on to serve as senior vice president and president of FirstEnergy Utilities in 2010, executive vice president and president in 2014 and to president and CEO in 2015.

Plea Deals

The government said the conspiracy began in March 2017 when Householder began receiving quarterly $250,000 payments through Generation Now, a 501(c)(4) nonprofit organization created to mask the payments.

In his plea Thursday, Longstreth admitted to organizing Generation Now with the knowledge that it would be used to receive bribe money to support Householder's bid for speaker. Longstreth managed the Generation Now bank accounts and made financial transactions to conceal that FES was a source of funding to Generation Now.

Cespedes *pleaded guilty* to orchestrating payments to Generation Now with the knowledge that the payments were intended to help Householder and his allies political campaigns in return for passing the nuclear bailout legislation.

Both men face up to 20 years in prison but may be looking for lighter sentences by testifying against Householder and the other two defendants, lobbyist Neil Clark and former Ohio GOP Chairman Matt Borges. U.S. District Judge Timothy S. Black, who accepted the pleas, said he would defer sentencing until the cases against the other defendants are resolved.

"There's a lot more shoes to drop, and there's a lot of nervous people today. I don't know who they are, but they do," Ohio Democratic Chairman David Pepper told *The Columbus Dispatch*. "It's no secret we believe the culture of corruption is absolutely overwhelming in Columbus now. Them turning state witness will lead to more information down the road about how far this plot went."

"Today's guilty pleas by Longstreth and Cespedes move the HB6 racketeering scandal from allegation to admitted fact," tweeted state Attorney General Dave Yost, who is pursuing civil litigation over the scandal. "The only remaining question: 'Who else?' My team, including a forensic accountant, is going through the first batch of documents in our civil racketeering lawsuit."

As of 8 p.m., FirstEnergy's stock price had dropped by 7.3% to $29.30 in after-hours trading. ■

Study Recommends Regionwide Carbon Price for PJM

By Michael Yoder

PJM can attain extensive decarbonization with lower costs to consumers by 2030 through the pursuit of market-based policies like carbon pricing instead of relying on various state clean energy policies and subsidies, according to a new study released Wednesday.

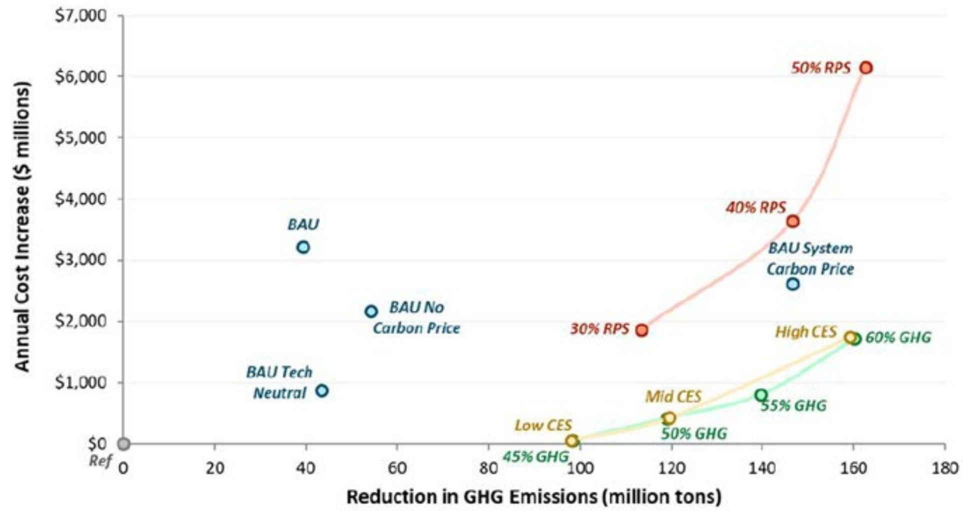
The *study*, "Least Cost Carbon Reduction Policies in PJM," was prepared by California-based consulting firm Energy and Environmental Economics (E3) on behalf of the Electric Power Supply Association (EPSA). It found that greenhouse gas emissions could be cut by 80 million metric tons, or roughly 28%, across the PJM region by 2030 with a carbon price of $10/ton. Such a price would keep annual costs at $2.8 billion less than the "business-as-usual" approach that includes a "hodgepodge of state and local clean energy policies," it said.

Status quo policies are more expensive and less effective than a regional approach on carbon pricing, the study found, with existing state carbon policies and subsidies projected to increase electricity costs by more than $3 billion in 2030 and achieving less than half (40 million metric tons) of emissions reductions that could be achieved through a competitive, market-based approach.

Arne Olson, E3 senior partner and the lead author of the report, said it found that the most effective carbon policies for PJM will be ones maximizing choices for market participants and that will "leverage resource and geographic diversity" across the RTO.

"Carbon pricing is shown to be the most efficient way to achieve deep levels of carbon reductions," Olson said.

Arne Olson, E3 senior partner | *EPSA*



PJM system costs and emissions savings in 2030 from current and alternative policy mechanisms | *E3*

The E3 study comes on the heels of FERC's proposed policy last month to invite states to introduce carbon pricing in their wholesale electricity markets, with Chairman Neil Chatterjee calling it a "landmark action." (See *FERC: Send Us Your Carbon Pricing Plans*.)

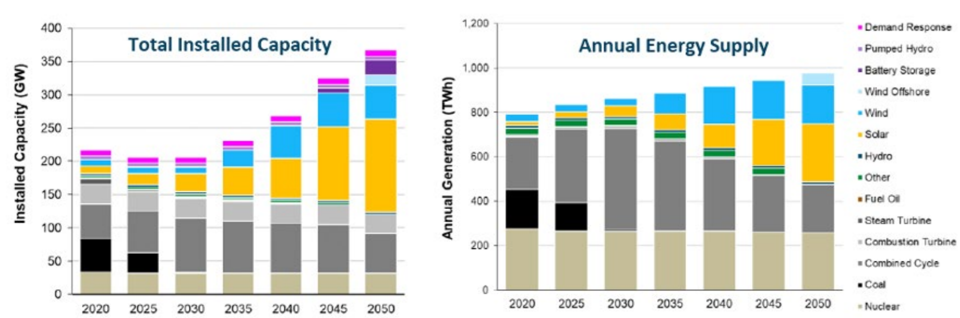
Olson said the study examined carbon-reduction policy cost impacts through 2050 and was designed to provide baseline information for PJM's stakeholders and policymakers as they decide the best ways to balance costs, reliability and the environment related to electricity generation.

Instead of constraining resource choices, Olson said, emissions can be efficiently and effectively reduced without hampering reliability by: a regional carbon price; encouraging competition and innovation; and allowing all resources and technologies to compete on a level playing field, including natural gas generation. Olson said the constraint of resource choices through state mandates and incentives increased costs in every scenario analyzed.

E3 also found that 50 to 90 MW of "firm, flexible natural gas generation" will be needed in PJM through 2045 to provide reliability. To meet 100% net-zero carbon emission targets, the report said, the development and innovation of "yet-to-be-developed technologies" will be necessary, with carbon pricing providing the best path to provide incentives for innovation instead of state subsidies.

EPSA CEO Todd Snitchler said the report's findings make clear that competition is key to a "more affordable, reliable and cleaner energy future."

"We have the tools we need to succeed right in front of us, with PJM's markets already saving customers money and driving down carbon emissions," Snitchler said. "This data should inform smart policy decisions in PJM and other markets — and EPSA and our members look forward to aiding that effort as competitive power suppliers continue to provide what customers, markets and the grid demand." ■



Installed capacity and annual generation in a PJM system under 80% GHG reduction by 2050 goals | *E3*

PJM News

PJM Updates Stakeholders on MOPR Filing

By Michael Yoder

Stakeholders got a look Thursday at PJM's initial response to FERC's ruling this month on its expanded minimum offer price rule (MOPR).

Chen Lu, PJM | © *RTO Insider*

Chen Lu, PJM senior counsel, presented the Markets and Reliability Committee with *highlights* of the order, issued Oct. 15, and the additional revisions the RTO must file by Nov. 16 (*EL16-49-003*, et al.). FERC accepted most of PJM's compliance filing while reversing its position on state-directed default service auctions. (See *FERC Acts on PJM MOPR Filing*.)

Lu said FERC largely accepted PJM's definition of a state subsidy, which included carve-outs for state default procurement auctions and for programs like the Regional Greenhouse Gas Initiative.

"We think this order results in a workably competitive outcome for the markets," Lu said.

The RTO has little discretion to modify the compliance language directed by FERC, so PJM does not anticipate any additional stakeholder meetings to complete the filing, he said.

MOPR Order Highlights

FERC indicated in the order that the upcoming Base Residual Auction (BRA) date cannot be set until an order on the pending energy and ancillary services compliance filing is resolved, Lu said. That filing was made by PJM in August, he said, with the hope of getting a decision by FERC before the end of the year.

Because pre-auction activities are pegged off the BRA date, Lu said, no deadlines for them may yet be set. PJM is currently evaluating activities that may begin on a voluntary basis for capacity market sellers wishing to start the process early, Lu said. A review of the pre-auction activities will be held with stakeholders at the Market Implementation Committee meeting Nov. 5.

Lu pointed to FERC's decision on the treatment of state default procurement auctions that have a renewable portfolio standard component. As long as they are competitive and nondiscriminatory and meet criteria outlined in the definition of state subsidy, Lu said, then they will not be deemed state subsidies.

But Lu called to attention a footnote in the order that reads, "While this order accepts the exemption that PJM has proposed, it does not constitute a ruling that any particular state-directed default service auction actually meets these requirements." FERC used New Jersey's auction as an example of an auction that would not meet its requirements. Commissioner Richard Glick highlighted this in his dissent, saying that New Jersey's and other state default procurement auctions that have an RPS component may be deemed by FERC to be a subsidy.

PJM is taking "a little bit of a different view" of the footnote, Lu said. The RTO believes the footnote is "meant as a cautionary tale" to warn New Jersey and other states not to change existing default state procurement auction rules in a way that would allow new renewable resources to escape the MOPR though the limited carve-out, he said.

The RTO is currently working with the Independent Market Monitor and will provide "guidance to all stakeholders" on how the existing state default procurement auctions in the footprint will be treated for the upcoming BRA, Lu said.

He also highlighted the scope of an exemption for incentives designed to promote "general industrial development in an area." He said the commission rejected a request by a party in the docket to "explicitly include entire electric generation resources" that may have benefited from some sort of industrial development.

FERC ruled that general pollution-control equipment should still be exempt from the definition of a state subsidy, while state programs like tax exemptions for standalone renewable facilities are not exempt and would be deemed a capacity resource with state subsidies.

Lu used as an example a *law* in Virginia that exempts property taxes for certain pollution control equipment and facilities. He said the definition of pollution-control equipment in Virginia includes entire solar facilities that would also be exempt from property taxes, thereby making it a state subsidy.

Stakeholder Questions

Ken Foladare of the Tangibl Group asked why PJM specifically highlighted renewable facilities in its presentation as generation resources benefiting from state subsidies. He said there are similar laws in other states benefiting natural gas- and coal-fired power plants, along with nuclear plants.

Ken Foladare, Tangibl | *Tangibl*

He pointed to a Kentucky law that says a company that owns and operates a coal-fired plant may be entitled to an incentive tax credit. He said almost every generation project he worked on had some sort of state or local tax incentive specifically designed for the generation facility being constructed.

"If you're going to be singling out solar, you're going to have to be singling out everybody," Foladare said. "And pretty much every plant in PJM is going to be subject to MOPR."

Paul Sotkiewicz, E-Cubed Policy Associates | © *RTO Insider*

Paul Sotkiewicz of E-Cubed Policy Associates asked what happens to the timing of a BRA if PJM and the Monitor cannot agree on state subsidy cases or if a market participant disagrees with a decision and appeals to FERC instead.

Lu said it is ultimately a capacity market seller's responsibility to certify if there is a subsidy or not, and FERC has already approved Tariff language describing how market sellers can challenge decisions.

Sotkiewicz said he views the process as being "thrown back on the market participant" to take the litigation and enforcement risk and ultimately dragged through a process that may vindicate their challenge in the end. He said it also "drags the entire market through a mess" where stakeholders are not sure what to believe in the market results.

"The more definitive we can be on this, the better off we are," Sotkiewicz said. "And this is not necessarily PJM's doing. The way FERC came down with this is a major part of the problem."

Monitor Joe Bowring said he recognizes there is still uncertainty surrounding the MOPR. He said his and PJM's goal is not to add any additional uncertainty in the process.

"We are making every effort to work closely with PJM to try to ensure we come to an agreement, make rational decisions and do it far enough ahead of time to minimize risk," Bowring said. ■

PJM MRC/MC Briefs

	Load Forecast Error Component 80th Percentile Absolute Error				Forced Outage Rate Component All Forced Outage Tickets				Day Ahead Scheduling
Season	2018	2019	2020	Rollup	2018	2019	2020	Rollup	Req.
Winter	2.25%	2.06%	2.05%	2.12%	3.66%	2.81%	2.19%	2.89%	5.01%
Spring	2.04%	1.84%	2.73%	2.20%	3.16%	2.24%	1.71%	2.37%	4.57%
Summer	2.48%	2.48%	1.95%	2.30%	2.81%	2.43%	2.34%	2.53%	4.83%
Fall	2.33%	1.13%		1.73%	2.59%	2.07%		2.33%	4.06%
Annual				2.18%				2.60%	4.78%

DASR Requirement Components | *PJM*

Markets and Reliability Committee

Liquidation Process Endorsed

The Markets and Reliability Committee endorsed revisions to PJM's rules for liquidating defaulted financial transmission rights positions by a sector-weighted vote of 4.59 (92%), easily surpassing the 66% threshold.

In December 2018, PJM implemented changes to its Tariff and Operating Agreement ending the practice of liquidating a defaulting FTR participant's open positions. This action followed GreenHat Energy's portfolio default. (See *FERC OKs Key PJM Changes to Address GreenHat Default*.)

PJM Chief Risk Officer Nigeria Bloczynski | © *RTO Insider*

Chief Risk Officer Nigeria Poole Bloczynski *reviewed* the revisions, saying work conducted at the Financial Risk Mitigation Senior Task Force made PJM determine its desire to re-establish the ability to liquidate defaulted FTR open positions in a "prudent and practical manner." Bloczynski said the RTO wants to provide flexibility in the way it exercises liquidation rights based on market liquidity, the size of the defaulted portfolio and market conditions.

The new rules would allow the RTO to liquidate defaulted FTR open positions by auctioning off portions of a portfolio across several regular auctions or conducting one or more special FTR liquidation auctions.

Bloczynski said PJM had several meetings with stakeholders since the issue was brought up at the September MRC meeting to address concerns that were raised and made enhancements to the Tariff and OA. (See "Liquidation Process," *PJM MRC/MC Briefs: Sept. 17, 2020*.)

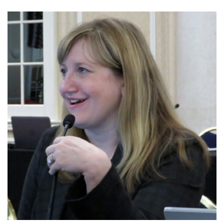
Some of the changes included renaming a section of *Attachment K* in the Tariff by removing the words "closing out" because it is not a defined term. Changes were also added to *Section 15.1* of the OA and *Attachment Q* of the Tariff.

James Ramsey of Perast Capital Management offered a *friendly amendment* to Attachment K that would provide notice to market participants "at least 24 hours prior to the close of an applicable financial transmission rights auction or special auction bidding window."

Several stakeholders asked PJM's opinion on the friendly amendment. Bloczynski said the RTO felt the proposed language was already "adequate" as far as transparency and advanced notice and that providing 24-hour notice before an auction closes would "likely be too late for most market participants."

Greg Poulos, executive director of the Consumer Advocates of the PJM States, objected to the friendly amendment based on PJM's opinion, taking it out of the endorsement vote.

Howard Haas, chief economist for Monitoring Analytics, said the proposal would give PJM too much discretion and provide no metrics to guide the RTO's decisions about how to how to exercise the discretion in deciding how to handle liquidations.



Susan Bruce, PJM Industrial Customer Coalition | © *RTO Insider*

Although she would vote for PJM's proposal, Susan Bruce of the PJM Industrial Customer Coalition encouraged the RTO to further flesh out the rules so impacted parties would have "rights of recourse."

"I understand PJM's looking for more discretion, and I respect that," Bruce said. "I think there's also great risk to market participants in that situation."

The changes were later endorsed by acclamation vote at the Members Committee meeting.

IRM Study Results Endorsed

Stakeholders endorsed an installed reserve margin (IRM) of 14.4%, down from 14.8% in 2019, along with new winter weekly reserve targets, though some questioned the RTO's "over-procurement" of capacity.

Patricio Rocha Garrido of PJM *reviewed* the *2020 Reserve Requirement Study* (RRS) results, which determined the final IRM and forecast pool requirement (FPR) for 2021/22 through 2023/24 and establishes the initial values for 2024/25. The results are based on the 2020 capacity model, load model and capacity benefit of ties (CBOT).

The 2020 capacity model is putting downward pressure on the IRM, Rocha Garrido said, with the average effective equivalent demand forced outage rate (EEFORd) of 5.78%, compared to 6.03% in the 2019 RRS. Rocha Garrido said the lower average EEFORd was caused by the increased representation of combined cycle units and gas turbines.

The CBOT — the help PJM can expect from imports during peak loads — is estimated to increase pressure on the IRM. Rocha Garrido said imports from neighboring RTOs have decreased from 1.6% in 2019 to 1.5% in 2020.

The FPR is essentially the same as 2019, Rocha Garrido said, coming in at 1.0865 (8.65%) instead of 1.086 the previous year.

The PJM and world load models used, based on the 2002-2014 period, were approved by the Planning Committee in August. Analysis from the *2020 PJM Load Forecast Report* released in January was also used.

Erik Heinle of the D.C. Office of the People's Counsel said his office "remains concerned" that that there is an over-procurement of capacity as a result of the load forecast, the IRM and other factors. Heinle abstained from the vote and encouraged PJM to consider using 15 years of historical data as a compromise, instead of the 10 years the OPC would like to see for forecasting and modeling.

"We want to continue a dialogue with respect to load forecasting and reserve margins," Heinle said.

Garrido said PJM is open to having a dialogue concerning procurement of capacity but said

PJM News

the megawatt number in the load forecast and capacity procurement has no impact on the calculated IRM values.

Poulos said there is “great concern” among the advocates about over-forecasting and over-procurement of capacity, calling it “one of the greatest concerns” of the group.

Joe Bowring, head of Independent Market Monitor Monitoring Analytics, said he agreed with Heinle’s complaint and would like to see the conversation about forecasting brought from the Load Analysis Subcommittee to a broader stakeholder group like the MRC. Bowring said forecasting has a broader impact on how the capacity market operates.

“PJM is over-procuring, and it clearly is a problem with the forecast,” Bowring said. “We would like to see a more detailed explanation of what it is in the forecasting process that has led to persistent over-forecasting.”

Day-ahead Scheduling Reserve Update

David Kimmel, PJM senior engineer, *reviewed* preliminary proposed changes to the 2021 day-ahead scheduling reserve (DASR) requirement during a first read. He said the numbers may change slightly when the measure is brought for final endorsement in November.

The DASR is the sum of the requirements for all zones within PJM and any additional reserves scheduled in response to a weather alert or other conservative operations. It is the sum of the three-year average of under-forecasted load forecast error (LFE) and the three-year average of eDART forced outages.

Kimmel said the preliminary 2021 DASR requirement is 4.78%, slightly lower than the

	Calculated IRM					Forecast Reserve					Other Expected Resources
	A	B	C	D	E	F	G	H	I	J	K
Delivery Year	IRM PJM RTO % (2 area)	IRM Outside World %	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Requirement (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	PJM Reliability Index without World Assistance (years/day)	Wind and Solar Nameplate MW
2020	14.9%	16.2%	6.1%	8.4%	1.0880	185,597	139,163	33.4%	25.3%	5.7	0
2021	14.7%	16.2%	6.0%	8.3%	1.0871	185,359	140,661	31.8%	23.9%	5.7	4,829
2022	14.5%	16.2%	5.9%	8.2%	1.0868	188,123	142,015	32.5%	24.5%	5.8	3,024
2023	14.4%	16.2%	5.8%	8.2%	1.0863	192,865	142,831	35.0%	27.0%	5.9	1,783
2024	14.4%	16.2%	5.8%	8.4%	1.0865	195,149	143,318	36.2%	28.0%	5.9	158
2025	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	144,143	35.4%	27.3%	5.9	20
2026	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	145,290	34.3%	26.3%	5.9	0
2027	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	146,187	33.5%	25.5%	5.9	0
2028	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	146,721	33.0%	25.1%	5.9	0
2029	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	147,218	32.6%	24.7%	5.9	0
2030	14.4%	16.2%	5.8%	8.5%	1.0865	195,149	147,757	32.1%	24.2%	5.9	0

Eleven-Year Reserve Requirement Study | *PJM*

2020 requirement of 5.07%. He said the number comes from the LFE component of 2.18% and the forced outage component of 2.6%.

Stakeholders will be asked to endorse the changes at the next MRC meeting. The final 2021 DASR value will be incorporated into Manual 13 changes and be implemented in January.

Members Committee

Schedule 9-2 Options Endorsed

Stakeholders unanimously endorsed near-term *changes* to PJM’s administrative rates as *recommended* by the Finance Committee.

PJM CFO Lisa Drauschak | © *RTO Insider*

PJM recovers its operating expenses through *Schedule 9* of the Tariff. CFO Lisa Drauschak, who *reviewed* the proposed changes, said 90% of Schedule 9 revenue is tied to actual load multiplied by a transmission factor, while the rest is connected to transactional activity.

The transactional FTR billing volume, which has increased 97% since 2011, is tied to Schedule 9-2, Drauschak said. The FTR administration service revenues have “significantly exceeded costs” because of an increase in the volume of FTR bidding activity, she said.

The Schedule 9-2 determinants are significantly higher than the assumptions used to build current stated rates, Drauschak said, which has led to the imbalance of revenues and expenses.

PJM is proposing to refund the excess collections over a “rolling 12-month period, based on service category net revenue.” The RTO is recommending an *amendment* of the Schedule 9 refund mechanism to allocate the excess collections. (See “Schedule 9-2 Options,” *PJM MRC/MC Briefs: Sept. 17, 2020*.) ■

— Michael Yoder

Transource Tapped for SPP's 2nd Competitive Tx Project

By Tom Kleckner

SPP last week awarded its second competitive transmission project under FERC Order 1000, hopeful that it will succeed where the first one failed.

The Board of Directors on Oct. 27 approved an industry expert panel's (IEP) *recommendation* to issue a notification to construct (NTC) to Transource Missouri, the panel's "designated transmission owner," for a 75-mile, 345-kV line in Oklahoma. The Sooner-Wekiwa project has a $66 million revenue requirement and an expected completion date of 2026.

The board approved Xcel Energy Southwest Transmission as the alternate builder.

The IEP evaluated 10 project bids under SPP's competitive *transmission owner selection process*. Three of those bids came from Transource and occupied the top three spots in the panel's intricate scoring matrix. The Transource bids were also the three most expensive, coming in between $66 million and $69 million. Projects submitted by other bidders ranged from $52.2 million to $64 million.

SPP awarded its first competitive project in 2016 to Mid-Kansas Electric, but the project was later canceled after load projections dropped. One stakeholder said at the time, "We went hunting for the project, we found it, we caged it — and we shot it." (See *SPP Cancels First Competitive Tx Project, Citing Falling Demand Projections*.)

As was the case four years ago, the competitive project's NTC went to an incumbent transmission provider, despite Order 1000's requirement removing federal rights of first refusal. Transource Missouri is one of several subsidiaries of *Transource Energy*, a competitive transmission joint partnership between American Electric Power and Evergy. AEP's Public Service Company of Oklahoma owns the Wekiwa substation's end point west of Tulsa.

Oklahoma Gas & Electric owns the Sooner Power Plant at the other end of the project. In years past, the two utilities would likely have negotiated construction responsibilities.

The five-person IEP determined Transource's winning proposal "best addressed a significant risk" to the project's success, that being "the timely acquisition of rights of way."

"This proposal also demonstrated significant capabilities and historical success in construction management and in the ability to operate and maintain a 345-kV transmission line," the panel said in its final report.

Transource has completed three projects, in Missouri, Nebraska and West Virginia, and has a fourth under development, the Independence Energy Connection in Pennsylvania and Maryland.

SPP's 2019 Integrated Transmission Planning *assessment* identified the Sooner-Wekiwa project as a potential competitive upgrade from among more than 1,600 proposed solutions submitted during the ITP process.

It estimated it would produce a 4.29 benefit-cost ratio under the Future 2 "emerging technologies" scenario, which assumed that electric vehicles, distributed generation, demand response and energy efficiency would increase energy growth rates, and that all coal and gas-fired generators over the age of 60 would retire. The assessment said the project will provide an alternate path for bulk power transfers to flow east to major SPP load centers, preventing flows from being diverted to the 138-kV system at Cleveland, Okla.

Requests for proposals were issued in early December 2019, requiring the IEP to be seated. The five-person panel, selected for its expertise in engineering design, project management construction, operations, rate analysis and finance, evaluated the project proposals in those categories. Five of the 10 proposals were submitted as detailed project proposals (DPPs), qualifying them for 100 incentive points each in the scoring. The other five were less detailed and did not qualify for the bonus points.

The winning proposal won a score of 877.9, topping the categories of Project Management and Operations and receiving the third highest point allocation for Engineering Design and fourth highest for Finance. Other projects scored from 517.8 to 871.9.

"I am very favorably impressed with the quality and thoroughness of the analysis of the submitted proposals," Board Chair Larry Altenbaumer said.

Xcel's Southwestern Public Service and Oklahoma cooperative Tri-County Electric were the only Members Committee representatives to vote against the recommendation.

"If you climb up to 35,000 feet, the present value revenue requirement for [Transource's proposal] is 20% higher than the alternative proposal," SPS President David Hudson said. "This is sort of showing the FERC 1000 process is actually costing SPP ratepayers more money. That isn't even considering the cost of staff administering the 1,500 DPPs. What is this FERC Order 1000 process costing customers versus what it is saving them?"

"This is sort of showing the FERC 1000 process is actually costing SPP ratepayers more money. That isn't even considering the cost of staff administering the 1,500 DPPs. What is this FERC Order 1000 process costing customers versus what it is saving them?"

—David Hudson, SPS President

The Advanced Power Alliance's Steve Gaw agreed, saying a FERC 1000 policy discussion is "ripe."

"It's clear there are some issues in SPP's Tariff that need to be thought through," he said.

Golden Spread Electric Cooperative's Michael Wise pointed out that the Strategic Planning Committee reviewed SPP's competitive process following the Walkemeyer project's selection four years ago. He said several improvements were made to the process.

"It might be necessary for the SPC to once again take up these issues," he said.

"We would welcome a stakeholder process to look at improvements," said IEP Chair Steve Strickland, a 35-year veteran of Entergy Arkansas. "This is only the second time we completed the process, and each time, we learned something new." ■

SPP Quarterly Briefing/RSC Briefs

Western RC Supports CAISO's RC During Energy Shortages

The new kid on the block, SPP's Western Interconnection reliability coordinator, stepped into the fray when CAISO's RC West experienced shortages this summer.

During the RTO's joint quarterly stakeholder meeting Oct. 26, Bruce Rew, senior vice president of operations, said the Western RC assisted with load sheds of up to about 1,000 MW Aug. 14-19, when CAISO, faced with energy shortages, first issued energy emergency alerts and then instituted rolling blackouts. (See *Theories Abound over California Blackouts Cause*.)

"We did help, as best we could," Rew said. "We worked closely with California and the RC West system as much as possible."

SPP's RC ensured all transmission and generation was available to the interconnection during the crisis. The RC did have to declare its own EEAs because of concerns about meeting reserves obligations, Rew said, but it did not shed load in its own nine balancing authorities.

The RTO's Western RC has only been online since December 2019. It will add 3.45 GW of generating capacity to its footprint next year when *Gridforce* Energy Management joins. (See *SPP Expands its Western RC Footprint*.)

Closer to home, Rew said SPP's peak load this summer was down slightly from the previous two years as it recovered from the pandemic's early effects. The largest spread came in early September when peak load was around 37 GW, compared to more than 45 GW in 2019 and almost 43 GW in 2018. Rew said mild weather and other issues were responsible for much of the drop.

The grid operator remains on track to have wind be its No. 1 fuel source this year. It added 3.6 GW of registered wind resources during the third quarter, bringing the total to 27.4 GW.

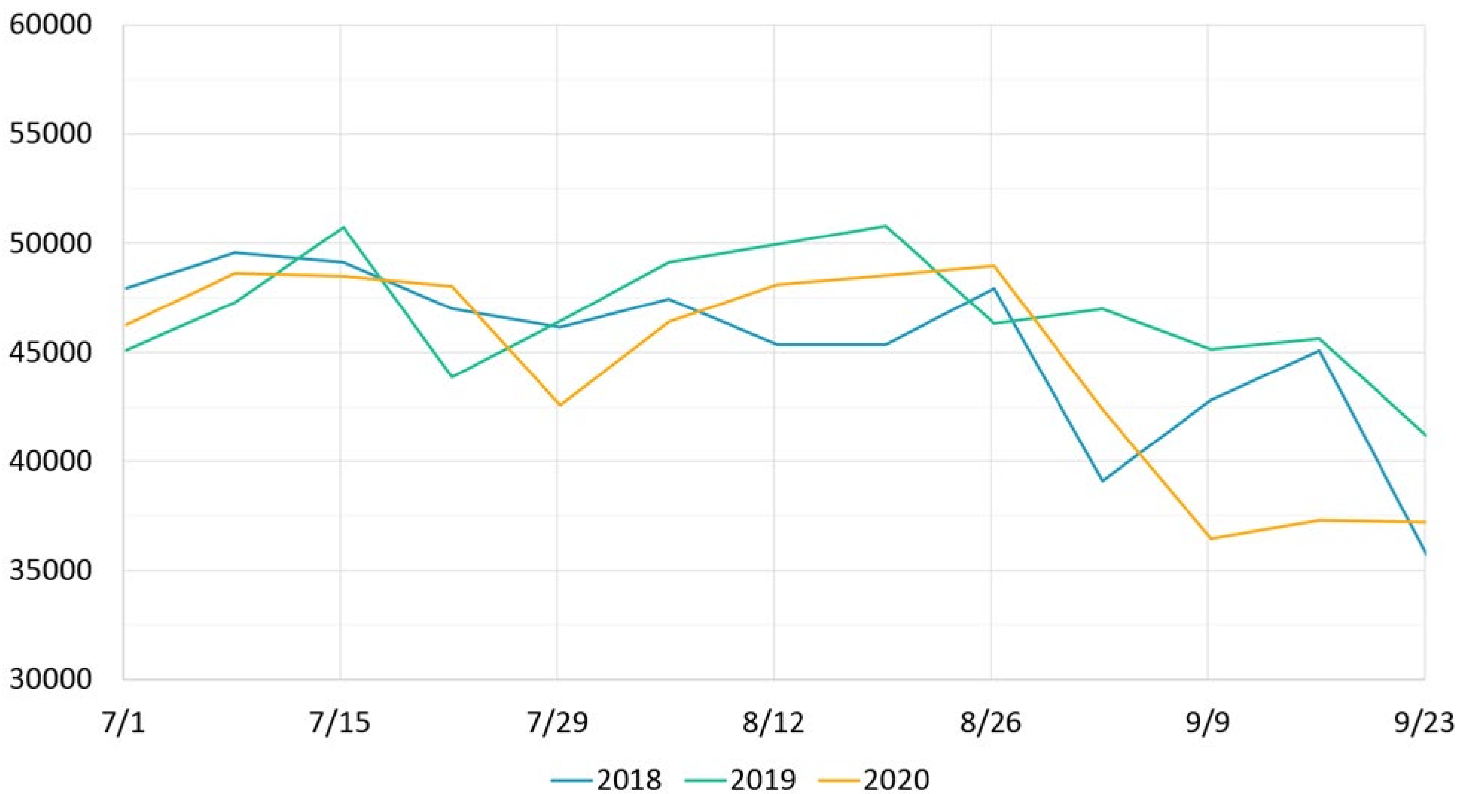
"We're a year ahead of schedule," CEO Barbara Sugg said.

With an increased reliance on wind energy comes a need for improved forecasting, Sugg said. The RTO's wind and solar forecasting error averages both improved during the third quarter from a year ago. The wind average was 3.80%, down from 4.54%, and the solar average was 4.70%, down from 5.66%.

Rew said SPP's Integrated Marketplace now has 264 participants, 177 of which are financial-only and 87 that own assets.

In other quarterly updates, a Strategic Planning Committee group picking up where a working group left off in trying to modify SPP's congestion-hedging practices by adding counterflow optimization is "trying to determine a path forward on this very complex issue," Director Graham Edwards said. He said the team will be reaching out to stakeholders before reporting back to the SPC in January. (See *SPP SPC Takes on Congestion Hedging Issues*.)

Director Mark Crisson, chair of the Strategic and Creative Re-engineering of Integrated Planning Team (SCRIPT) responsible for



SPP's peak load this summer was down when compared to the previous two. | *SPP*

SPP News

re-engineering SPP's transmission-planning processes, said the group has developed a scope and created four sub-teams to handle much of the work. The SCRIPT plans to bring a final report to the Board of Directors for its consideration and approval in October 2021.

SD's Fiegen to Lead RSC in 2021

The Regional State Committee approved the nomination of South Dakota Public Utilities Commissioner Kristie Fiegen as its next president, effective in January. The committee also voted to have North Dakota Public Service Commissioner Randy Christmann serve as its next vice president and Texas Public Utility Commission Chair DeAnn Walker as secretary and treasurer.

Outgoing President and Nebraska Power Review Board Member Dennis Grennan offered to virtually hand over the gavel to Fiegen following the meeting, but she had other ideas.

"You can drive on up," Fiegen said, teasingly offering to take Grennan pheasant hunting if he did.

"I'll leave after the board meeting," Grennan responded.

The RSC will also welcome Arkansas Public Service Commission Chair Ted Thomas next year. He will replace his PSC colleague Kimberly O'Guinn, who is taking his seat on the Organization of MISO States.

The committee also approved its 2021 budget, despite concerns over a travel and meetings budget that was trimmed by 38.7% from the year before. The budget totals $326,100, but travel and meeting expenses have been cut from $280,497 to $172,000.

Kristie Fiegen | *South Dakota PUC*

SPP has recently looked at alternating the quarterly governance meetings between virtual and in-person to reduce costs. Taking advantage of what it has learned from conducting seven months of meetings over the internet or the phone, the RTO will make that change next year.

"I would like to keep travel as is," Louisiana Public Service Commissioner Mike Francis said. "It really helps my commission more if we are meeting in person. I really think we'll figure out how to handle" the COVID-19 pandemic.

"I don't disagree," Grennan said. "The sooner we can get back to where at least a portion of our meetings are face to face, the better."

CAWG to Pause Pricing Zone Work

The RSC directed its Cost Allocation Working Group to remain focused on decoupling SPP's Schedule 9 and 11 transmission pricing zones while it waits on a white paper from a competing task force.

Oklahoma Corporation Commission staffer Jason Chaplin said the CAWG has been unable to reach consensus on the issue, saying there is a "slight lean" toward keeping the RTO's existing methodology. The Holistic Integrated Tariff Team (HITT) had tasked the working group with separating the two pricing zones and allowing the creation of larger Schedule 11 pricing zones and/or Schedule 9 sub-zones, taking into consideration new deliverability sub-regions, distribution factor calculations, and market and power flows.

"With this issue, addressed appropriately, we would solve the zonal placement issue," Nebraska Public Power District's Tom Kent, who chaired the HITT, told the RSC. "I don't want us to lose momentum in getting this issue right."

CAWG Chair John Krajewski, who consults with the Nebraska Power Review Board, suggested the group slow down its work, "so slow, it's almost a pause."

The group's work has been hamstrung while it waits on a deliverability report from the NRIS/ERIS Deliverability Task Force (NEDTF), which the HITT asked to develop policies creating a balance between energy resource interconnection service (ERIS), network resource interconnection service (NRIS), generator-interconnection products and long-term firm transmission service.

The NEDTF's *white paper*, which includes a recommendation to replace NRIS with a new capacity resource interconnection service (CRIS), was only approved by the Markets and Operations Policy Committee earlier in October. The task force says CRIS would add deliverability to the existing NRIS product and provide a clearer distinction between the two services. (See "Interconnection Improvements," *SPP MOPC Briefs: Oct. 13-14, 2020*.)

Dennis Grennan presides over his last RSC meeting as president. | *SPP*

The SPP board would also approve the document the day after the RSC meeting.

"If we pause to do more data and do a meaningful analysis, that makes sense," Kansas Corporation Commissioner Andrew French.

The CAWG agreed to provide a new work plan this month and updates to the RSC in January and April. The work was originally to have been completed in July.

The RSC did endorse the CAWG's recommendation to implement previously approved language that creates a narrow process to regionally allocate costs for transmission projects between 100 and 300 kV primarily used to move power out of the local transmission pricing zones.

New Mexico Public Regulation Commissioner Jeff Byrd opposed *RTWG RR422*, while Francis, Walker and OCC Commissioner Dana Murphy abstained.

The MOPC approved the measure during its October meeting. (See "Some Byway Costs to be Allocated Regionally," *SPP MOPC Briefs: Oct. 13-14, 2020*.) ■

— Tom Kleckner

SPP Board of Directors/MC Briefs

RTO Gets 2021 Budget Approval, Must Cut $4M in Expenses

SPP's Board of Directors last week approved 2021 operating and capital budgets that bend to the realities of COVID-19 and its potential economic impacts.

The budget includes $4 million in "controllable expenditures" that stakeholders recommended be eliminated to balance a net revenue requirement (NRR) they said was too high.

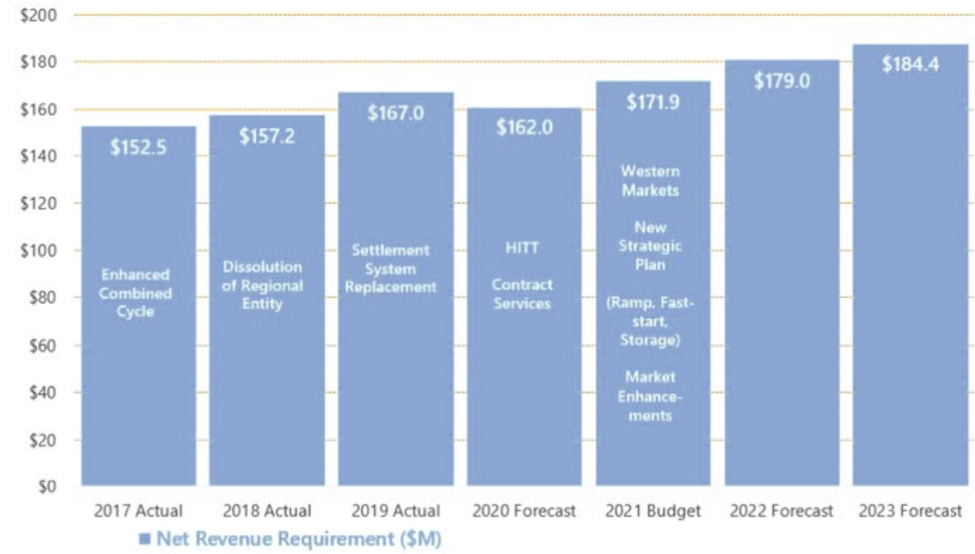
"Given this year and the unusual circumstances and what has happened to the markets, everyone is feeling the pain financially," Director Susan Certoma, chair of the Finance Committee, told the board and Members Committee during their meeting Oct. 27. "The challenge was, could we also think about our controllable expenses and what we could do with those? There are not that many levers that can be used by SPP."

American Electric Power and Oklahoma Gas & Electric pressed the Finance Committee to keep the budget as flat as possible and said there should be a heightened focus on "controllable expenditures." Those expenses include compensation, travel, meetings, consulting and maintenance, but Certoma said there is no "detailed plan" of which costs to cut.

"Staff will determine how they meet that challenge," she said.

"The budget reflects the impacts and uncertainty of the pandemic, as well as our ongoing commitment to deliver high-quality services at the lowest possible cost," CEO Barbara Sugg said.

CEO Barbara Sugg | © *RTO Insider*



SPP's actual and budgeted/forecasted net revenue requirement for 2017-2023 | *SPP*

The Members Committee, which advises the board, unanimously endorsed the budget recommendation.

The actions will result in an NRR of $155.3 million, with net favorable variances in revenues and operating expenses resulting in a projected over-recovery of $16.6 million. SPP is currently forecasting a $153 million NRR this year that will result in an $18.9 million administrative fee over-recovery. Meeting and travel restrictions are contributing to the variance.

Revisions to Schedule 1A of SPP's Tariff will take effect in January, following FERC approval earlier this year. The changes replace the grid operator's broad rate schedule with four targeted ones (*ER20-418*). (See "Board Approves Modernized Cost-recovery Structure," *SPP Board of Directors/Members Committee Briefs: Jan. 29, 2019*.)

The revisions also replace SPP's administrative fee with a calculation that limits the annual budgeted NRR to a ratio not exceeding 0.43:1 of estimated annual transmission usage, expressed in megawatt-hours. Staff estimate next year's ratio to be 0.396:1, the equivalent of a 39.6-cent/MWh administrative fee. This year's fee was set at 43 cents/MWh.

The NRR represents SPP's funding necessary to provide services throughout its footprint. It comprises operating expenses (excluding depreciation and FERC assessment), principal payments on loans for capital expenditures and a capital reserve fund.

SPP's gross revenue requirement of $188 million for 2021 is a $10 million increase over the 2020 forecast, stemming from an increase in scheduled principal payments on the RTO's outstanding and new term debt, and lower 2020 operating expenses associated with the pandemic.

The RTO's 2021 operating plan, with the strategic plan serving as the foundation, was used as a guide to develop the budget.

Directors Accept $532M Tx Plan

The board approved staff's $532 million 2020 *Integrated Transmission Plan* and its 54 projects, overriding member concerns about transmission costs and the projected benefits. The plan, which includes 92 miles of 345-kV transmission lines and 141 miles of rebuilt high-voltage infrastructure, was developed over 27 months of collaboration between staff and stakeholders.

SPP said the upgrades will solve 163 grid issues and should reduce wholesale energy congestion costs while providing estimated future net savings of up to 30 cents on the average monthly residential bill, thanks to a projected 4- to 5.2-to-1 benefit-to-cost ratio.

Golden Spread Electric Cooperative, Liberty Utilities, NorthWestern Energy, OG&E and Oklahoma Municipal Power Authority voted against the plan in the Members Committee.

"We feel we should be giving more credence to the lower-cost options out there," said OG&E's

SPP News

Greg McAuley, noting that a $30 million project the utility advocated for was passed over in favor of a $100 million project that had a better adjusted production cost (APC) but resolved less congestion.

Two of the project-cost hawks suggested they will take their concerns to the Strategic and Creative Re-engineering of Integrated Planning Team (SCRIPT), which is responsible for re-engineering SPP's transmission planning processes. The SCRIPT plans to bring a final report to the board for its consideration and approval next October.

"We're not real pleased with the cost-benefit calculations. We will be actively working with the SCRIPT to clarify how we calculate those benefits," Golden Spread's Michael Wise said. He said SPP's calculation of benefits by extrapolating five- and 10-year APC out to 15 years and then using inflation or discount-rate measures to reach 40 years is a "leap of faith" when compared to more easily computed 40-year costs for completed transmission.

"We should ensure consumers they're paying for 40-year projects that will really be beneficial," Wise said.

"I look at the ITP proceedings, and I think the SCRIPT team is very timely," Nebraska Public Power District's Tom Kent said. "I'm growing very concerned about transmission costs. Now is the time to take a hard look at the metrics, especially when the footprint is so rich in generation. As we add more renewables, one has to wonder if we're heading down the right path and what the reliability impacts are."

The board also approved a nearly $91 million increase for NPPD's 345-kV *R-Project* following the Members Committee's unanimous endorsement. The approval raises the project's price tag to $463.4 million.

McCauley, who was among those calling to suspend and re-evaluate the project during the Markets and Operations Policy Committee's consideration two weeks prior, said he was changing his mind after talking to NPPD. (See "$91M Increase for NPPD's R-Project," *SPP MOPC Briefs: Oct. 13-14, 2020*.)

"Given the circumstance … I think NPPD has done what they can do," he said. "In spite of that, this situation points out in stark clarity the risk association with building transmission. The fact that it happened to a project of this size and scope, it can happen anywhere. There are unforeseen circumstances that pop up and create risk."

Arkansas COVID Cases in Wrong Direction

Sugg opened her president's report by showing a slide "we're not particularly proud of" — a chart of the increasing new COVID-19 cases in Arkansas.

SPP has based its return to the office and in-person meetings on a 14-day downward trend in cases. Arkansas, home to the RTO's headquarters, has exceeded the peak of active cases it set in mid-August. The state *reported* a near record 1,316 new cases on Saturday and 25 deaths, raising the respective totals to 103,482 and 1,925.

"Clearly, we've not met our criteria for returning to the office," Sugg said. "The statistics will have to improve, or that return will be delayed further. It's just not favorable for us."

SPP will continue to hold virtual stakeholder meetings through the first quarter of 2021. Ironically, Sugg said the grid operator last year had contemplated increasing its use of virtual meetings to reduce travel costs and meeting expenses.

Sugg said staff are continuing to work through COVID-19's effects, with the control centers yet to report a single infection. She did allow that she and other executives were conducting the board meeting from their corporate office, noting that "we have better Wi-Fi than at home."

The first-year CEO said the most interesting thing on her plate is the work SPP has been doing with MISO. The seams neighbors have collaborated closely on restoration efforts in Entergy's footprint, which has been wracked by several storms during the 2020 hurricane season. The RTOs are also developing the scope for their planned joint transmission study. (See *MISO, SPP Heads Present Unified Front on Seams*.)

"The coordination between the two organizations has been outstanding," Sugg said. "MISO has been absolutely challenged and appreciates the coordination with SPP. We're very dependent on each other in that part of the country. I am very, very optimistic we'll make progress working together."

Con Ed Veteran Elected to Board

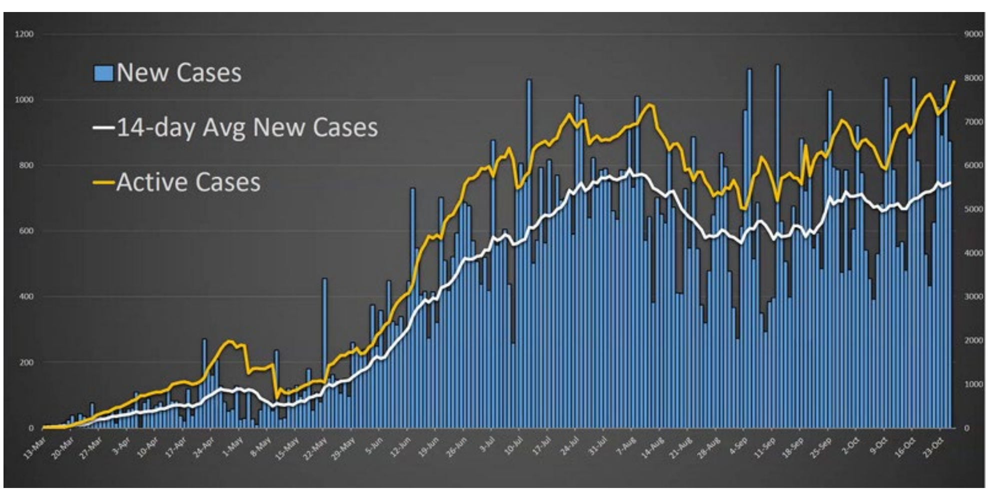
Members elected former Consolidated Edison General Counsel Elizabeth Moore to the board. Moore, who has 30 years of experience in the regulatory sector and energy industry, will serve the remainder of the late Bruce Scherr's term and will begin a new three-year term in January. (See *Former NERC Vice Chair Scherr Dies at 72*.)

Moore served as counsel to New York Gov. Mario Cuomo and has been named as one of the "25 Influential Black Women in Business" by *The Network Journal*. She is currently director emeritus on the board of trustees at her alma mater, Cornell University.

Board Chair Larry Altenbaumer and Director Joshua W. Martin III were re-elected to three-year terms.

Members also elected Advanced Power Alliance's Steve Gaw to fill the new Alternative Power/Public Interest sector's seat on the committee and then to an additional three-year term in 2021.

Re-elected to three-year terms were Tri-State Generation and Transmission Association's Joel Bladow (Cooperatives); Xcel Energy's David Hudson (Investor-Owned Utilities); Omaha Public Power District's Joe Lang (State); OG&E's McAuley (IOUs); OMPA's Dave Osburn (Municipals); and Google's Jeff



COVID cases in Arkansas have been on an upward trajectory. | *SPP*

SPP News

Riles (Large Retail Customer).

Board Approval for HITT Proposals

The board signed off on a revision request and several white papers stemming from the Holistic Integrated Tariff Team's (HITT) *recommendations*, designed to help SPP successfully meet the ever evolving grid's challenges.

The white papers were approved unanimously, but the HITT's proposal that the RTO implement a new cost-sharing methodology for qualifying 100- to 300-kV transmission projects that primarily move power out of local transmission pricing zones met opposition from Southwestern Public Service, OG&E, Public Service Company of Oklahoma, Liberty Utilities and City Utilities of Springfield (Mo.).

The measure (*RTWG RR422*) would fully allocate those qualifying projects on a regional basis. Transmission owners have largely opposed the proposal, saying it would shift byway cost responsibility from wind-rich areas to others.

The Energy Resource Interconnection Service/Network Resource Interconnection Service (NRIS) Task Force brought forward a 72-page *white paper* that recommends replacing NRIS with a new capacity resource interconnection service (CRIS).

CRIS provides capacity deliverability from a single resource to any load within a control area, balancing authority or other designated region that contains more than a single load. NRIS provides a generator with a sufficient interconnection to allow it to qualify as a designated network resource on the transmission provider's system without additional network upgrades.

The board also approved white papers on economic outage coordination, topology optimization and adding new load to the grid, all of which received unanimous approval from the Members Committee.

The first *white paper* recommends using existing transmission assets to increase grid flexibility and efficiency. The document says that while transmission elements are traditionally viewed as static elements, their topology reconfigurations may provide a means to reliably reroute power around congested facilities without causing additional burden on the system.

The economic outage coordination *white paper* evaluated other RTOs' outage-coordination processes and criteria thresholds before concluding SPP will need to invest time and money fully integrating and streamlining the process to take full advantage of the economic benefits.

A Transmission Work Group's *paper* documents proposed modifications to Tariff Attachment AQ that would limit its application to new load, revisions to loads and load retirements that need to be addressed outside of the ITP because of timing or some other "significant" reason.

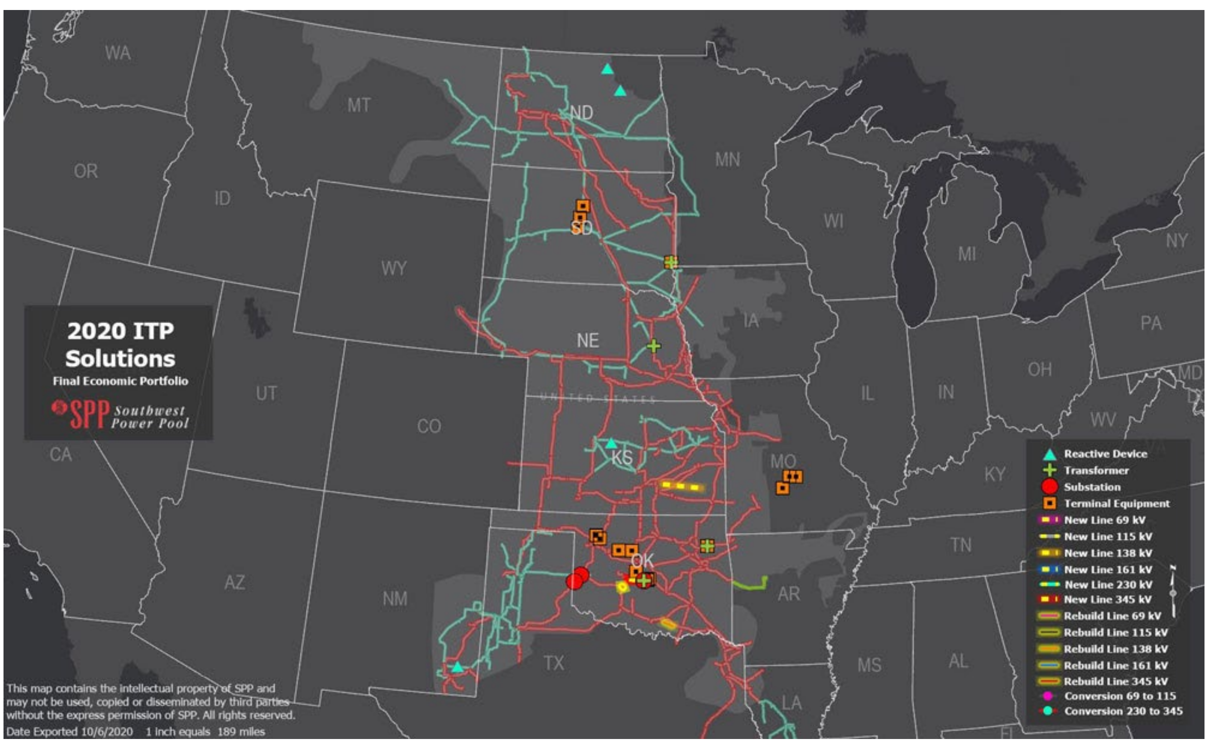
CGC Fills Out Key Stakeholder Positions

Members and the board approved the consent agenda, which included:

- the Corporate Governance Committee's nominations of SPS' Bill Grant, Evergy's Kevin Noblet, EDP Renewables' David Mindham and OMPA's Melie Vincent to four-year terms on the Strategic Planning Committee. Arkansas Electric Cooperative's Andrew Lachowsky was nominated to a vacant seat that expires in 2023.
- the CGC's nominations for Kansas Electric Power Cooperative's Suzanne Lane to the Human Resources Committee and Lincoln Electric System's Laura Kapustka to the Finance Committee, both for four-year terms.
- the CGC's recommended bylaw and membership agreement revisions clarifying that withdrawing members' financial obligations are applicable to partial terminations when only some of their transmission facilities are pulled back from SPP. The committee also clarified that non-TOs become TOs upon transferring functional control of Tariff facilities to SPP.
- the Supply Adequacy Working Group's *RR412* that allows both new and upgraded capacity from existing generators to be treated equally in qualifying as accredited capacity during the first peak season that each is available, thereby preserving the members' expected generation investment value.

The consent agenda also included approval of a $14.67 million increase above the $32.46 million original estimate for Empire District Electric and Evergy Kansas Central's 161-kV rebuild in eastern Kansas; an additional 161/69-kV transformer for Apex Clean Energy's Jayhawk Wind project in eastern Kansas; modification of an East River Electric Power Cooperative 69-kV project; withdrawal of two notifications to construct; and the 2020 annual violation relaxation limits *report*. ■

— Tom Kleckner



The 2020 ITP's economic projects | *SPP*

SPP News

Mixed FERC Rulings for SPP Compliance Filings

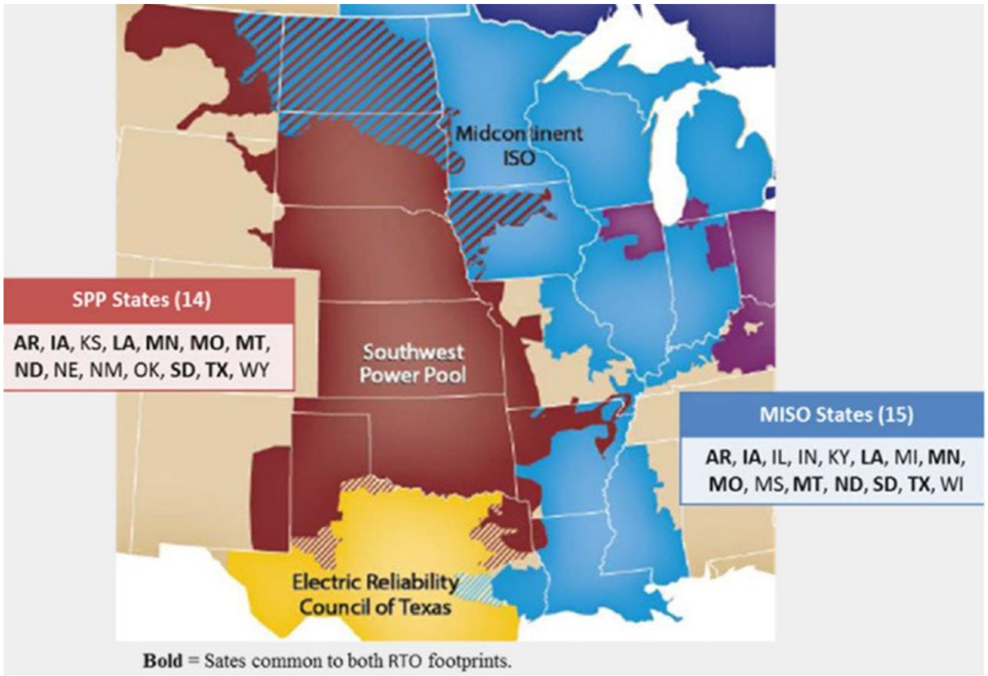
More Work to Do on GI Studies Along MISO Seam

By Tom Kleckner

FERC last week approved SPP's compliance filing responding to orders calling for more transparency into how RTOs analyze each other's systems during interconnection studies (*ER20-943*).

In a letter order Friday, FERC accepted revisions to the SPP-MISO joint operating agreement (JOA) that point to where interconnection customers can find the RTO's modeling details used in affected-system studies; added details to the sink assumptions; provided for more frequent information exchange during SPP's three-phase interconnection process; and corrected an administrative error.

SPP's revisions provided a specific section number for its generator interconnection process and business practices guidelines within Attachment V of its Tariff, where energy resource interconnection service (ERIS) and network resource interconnection service (NRIS) modeling information is contained.



The SPP-MISO seam | *Organization of MISO States*

The commission in October rolled back a portion of an earlier ruling, saying SPP, MISO and PJM don't have to rely on one another's dispatch assumptions to carry out an affected-system study. FERC had ruled in 2019 that the RTOs' JOAs do not provide enough clarity on how they handle generator interconnection studies along their seams. (See *FERC Walks Back Part of Affected-system Order*.)

In a related order, the commission directed SPP to make a further compliance filing regarding affected-system coordination procedures (*ER20-945*).

FERC asked the RTO to explain why it proposed placing ERIS and NRIS modeling information in a particular section of the guidelines for the interconnection process and business practices, but not the section that provides the ERIS and NRIS modeling details the grid operator uses to study interconnection requests on its own system.

Commission Accepts FSR, Rate Schedule Changes

The commission last week accepted compliance filings in two other SPP dockets.

In a proposal to revise the grid operator's fast-start pricing practices, SPP further revised its Tariff to provide that, for pricing purposes, fast-start resources' (FSRs) composite offers will be calculated with commitment costs "in effect at the time of the commitment."

The RTO also added language clarifying that an FSR's commitment costs will be amortized over its maximum economic capacity operating limit and its minimum run time, and explaining how it calculates the commitment costs added to each breakpoint on the FSR's energy offer curve (*ER20-644*).

FERC in July found that SPP's original fast-start pricing revisions did not allow prices to reflect the marginal cost of serving load. (See "Directs Further Compliance Filing on Fast-start Resources," *FERC OKs 2 Changes from SPP's HITT Work*.)

The commission also accepted SPP's Tariff revision clarifying the calculation of the transmission congestion rights (TCRs) administration service charge (*ER20-2628*).

FERC in February approved the RTO's revisions to Schedule 1A of its Tariff that replace a broad rate schedule with four targeted ones, effective Jan. 1, 2021 (*ER20-418*). The new schedules take effect in January. (See "Board Approves Modernized Cost-recovery Structure," *SPP Board of Directors/Members Committee Briefs: Jan. 29, 2019*.)

However, SPP discovered that the language mistakenly specified that the TCR service charge is calculated at the settlement location level. It added language that clarifies the charge type is calculated at the asset owner level and that two of the other new schedules are calculated at the settlement location level.

NIMECA, Corn Belt Finally Settle

FERC on Oct. 26 approved an uncontested partial settlement and settlement agreement between North Iowa Municipal Electric Cooperative Association member cities and other parties over their annual transmission revenue requirement, formula rate templates and formula rate implementation protocols (*ER15-2028*).

The settlement resolved all issues set for hearing other than those related to Corn Belt Power Cooperative's ratemaking treatment of its grandfathered agreements (GFAs), ATRR and formula rate template. The GFAs were a sticking point during hearing and settlement judge procedures that began in 2015.

Joining Corn Belt as intervenors were the Missouri Public Service Commission, Basin Electric Power Cooperative, MidAmerican Energy, Interstate Power and Light, and Missouri River Energy Services. ■

Company Briefs

AEP to Buy Energy from Columbus Solar Farm

AEP Energy Partners last week said it is finalizing a long-term power purchase agreement with BQ Energy Development for 100% of the power that will be generated at the new 50-MW Columbus Solar Park.

AEP will use the park to meet demand for renewable energy and future renewable needs should the city succeed in its aggregation initiative.

The project is expected to be completed in December 2022.

More: *Columbus Business First*

Ameren Says Continued Upgrades Will Extend Nuclear Plant's Life

Ameren Missouri last week said the Callaway Energy Center nuclear power plant will receive upgrades to extend its operational life and increase its efficiency through the next 24 to 44 years. The plant is licensed to operate through 2044, but Ameren plans to seek a renewal until 2064.

The company has included the plant as part of its strategy to cut carbon emissions by 50% over the next 10 years and have net-zero carbon emissions by 2050.

More: *News Tribune*

AES Names Lund as CEO of Utility Subsidiaries

AES last week announced that it had named Kristina Lund as president and CEO of utility subsidiaries Dayton Power & Light and Indianapolis Power & Light.

Lund is a senior executive with a 15-year tenure at AES. Most recently she was chief product officer for carbon-free energy. Prior to that role, she served as a regional CFO. She has led financial affairs and execution for AES businesses in 13 countries that represented more than $10 billion in assets, the company said.

AES also announced that company President Lisa Krueger is now executive chair of the boards for both utilities' respective holding companies, DPL and IPALCO.

More: *Inside Indiana Business*; *DP&L*

PGE's Lobdell to Retire

Portland General Electric last week announced that Jim Lobdell, senior vice president of finance, CFO and treasurer, plans to retire at the end of the year after 36 years with the company.

Jim Ajello, former CFO of Hawaiian Electric Industries, will join PGE as a senior adviser Nov. 30 before taking over as CFO on Jan. 1. Ajello was HEI's CFO from 2009 to 2017 and currently serves as an independent member of the company's Hawaiian Electric utility subsidiary's board of directors.

The company also announced that Brett Sims, senior director of strategy, commercial and regulatory affairs, would become vice president of strategy, regulation and energy supply on Friday.

More: *PGE*

Federal Briefs

IEA Says Severe Weather, Cyberattacks Threats to Renewables

The International Energy Agency last week released a paper titled "Power Systems in Transition" that identified variable renewable sources, cyberattacks and extreme weather as threats to future energy supply.

The study also looked at the "extremely challenging" reality for wind and solar technologies to grow fast enough to push out nuclear and fossil fuel plants. To reach emission-reduction goals, the deployment of wind and solar would have to "accelerate substantially" and become "dominant sources" in parts of an interconnected system.

Clean energy transitions will bring a structural change to electricity systems around the world, with variable renewable generation already surging over the last decade. The average annual share of variable renewables in total generation would reach 45% by 2040, according to the IEA's Sustainable Development Scenario.

More: *Windpower Monthly*

UN Plan Charts US to Net-zero Carbon Emissions by 2050

A U.N.-linked initiative, the Zero Carbon Action Plan, was released last week and presents an avenue for the U.S. to hit net-zero carbon emissions by 2050.

The research found that a transition to entirely clean sources would only cost only 0.4% more of the U.S.' gross domestic product than sticking with fossil fuels. The plan calls for reducing the carbon footprint of the electricity sector by 60% by 2030. While the proposal would end coal use, it does not fully transition away from fossil fuels and cites a need to rely on natural gas to help with the intermittency of renewable sources.

More: *The Hill*

Trump Orders Report Examining Impacts of Fracking Ban

President Trump on Saturday directed his administration to put together a report on what the effects would be of putting a ban or tighter restrictions on fracking.

The order directs Energy Secretary Dan Brouillette to submit reports within 70 days on both the economic and national security implications of banning or restricting fracking. The order comes as Trump has sought to differentiate himself from his Democratic opponent in today's presidential election, former Vice President Joe Biden, on the issue. The president tweeted that he signed an order to "protect fracking and the oil and gas industry," although the order wouldn't actually directly cause any policy changes.

Trump continues to claim that Biden wants to ban fracking in a bid to win states like Pennsylvania. Meanwhile, Biden has repeatedly said he does not want to ban the practice, except in the case of issuing new permits on public lands. But he also said during a recent town hall that it has to be "managed very, very well."

More: *The Hill*

State Briefs

ARIZONA

ACC Approves Plan for 100% Carbon-free Power by 2050

The Corporation Commission last week voted 3-2 to approve a plan for utilities to get all their energy from carbon-free sources by 2050.

The new regulations require utilities to get half their power from renewable energy by 2035. By 2050, they would need to supply all demand with either renewables, carbon-free nuclear or energy-efficiency measures such as subsidizing low-watt lightbulbs or attic insulation.

Carbon reductions would be based on how much carbon a utility's plants emitted on average from 2016 to 2018.

More: *The Arizona Republic*

IDAHO

Idaho Power to Leave Nevada Coal Plant 3 Years Early

Idaho Power last week said it will leave its Valmy coal plant in Nevada three years early and stop all coal use by 2030 as it moves toward its goal of using all clean energy sources by 2045.

The utility jointly owns the Valmy plant with NV Energy. The decision to leave the plant early was made in the company's integrated resource plan, which was completed this month. A company official said the decision will save customers $3 million.

Idaho Power hopes to make up for the lost capacity with imports from Nevada through the same transmission line south of Twin Falls. If it can't, it will put out a request for proposals that could include programs to manage demand, renewables or battery storage, it said.

More: *Idaho Statesman*

ILLINOIS

Turbine Setbacks Recommended to Piatt County Board

The Piatt County Zoning Board of Appeals last week voted unanimously to recommend an amendment to its current large Wind Energy Conversion ordinance to mandate setbacks of 1.3 times the tower tip height to the nearest nonparticipating primary structures, or 1,600 feet, whichever is greater. The current ordinance mandates setbacks of 1.1 times the maximum tip height or 1,600 feet.

The increase from 1.1 to 1.3 times the blade tip height will likely not add any distance to setbacks, as the ordinance mandates a minimum of at least 1,600 feet. For a 467-foot tip height — which is how tall the blades are on Apex Clean Energy's Hoopeston wind farm — the 1,600-foot minimum would take hold.

The recommendation will be considered by the county board on Nov. 12.

More: *Piatt County Journal-Republican*

IOWA

Solar Farm Coming to Waterloo

The Waterloo Board of Adjustment voted 4-1 last week to approve the construction of MidAmerican Energy's 3-MW solar farm despite objections from the public.

Most residents said they did not oppose solar energy but did not like the location of the farm. MidAmerican said it examined other sites, but the options did not work because of future development plans or the distance from an existing power substation.

Construction is slated for spring 2021 and is expected to take five months.

More: *The Courier*

MICHIGAN

PSC Approves Consumers' Cost Recovery Reconciliation

The Public Service Commission last week approved Consumers Energy's reconciliation of its power supply cost recovery expenses and revenues for the 2018 calendar year but disallowed costs associated with two power plant shutdowns that the company had asked to recoup.

The PSC approved the utility's reconciliation of its 2018 demand response program costs that resulted in an overcollection of $1.76 million that will be refunded to customers in the next rate case.

Consumers tried to recover about $2.6 million in costs stemming from an unplanned 20-day shutdown of its Karn power plant in fall 2018. During the shutdown, Consumers also performed other maintenance work to prevent other future outages, avoiding power replacement costs of $966,000 for 20 days of separate shutdowns that the maintenance work would have otherwise required. The PSC disallowed the $2.6 million, except the $966,000, on concern about flaws in the company's processes and procedures for plant modifications.

More: *Michigan PSC*

MONTANA

NorthWestern Customers Pay $14.3M in Unexpected Costs

The Public Service Commission last week said NorthWestern Energy customers will be responsible for $14.3 million in unexpected power costs stemming from a 12-month period from July 2018 to June 2019.

State law allows monopoly utilities to bill first and respond to questions later about unforecasted expense claims. NorthWestern's customers saw a one-year rate increase of $23.8 million starting in October 2019, but the hearing on whether those costs were justified did not take place until June 2020. The $14.3 million is what commissioners determined appropriate, although NorthWestern will have to credit back the difference to customers, with interest ($9.4 million with $523,000 interest).

At the center of NorthWestern's $23.8 million claim was replacement power bought during a 77-day period in 2018 when Colstrip Units 3 and 4 failed to comply with the federal Mercury and Air Toxics Standards.

More: *Billings Gazette*

NEW JERSEY

BPU Hires Deputy Director to Lead Clean Energy Equity Work

The Board of Public Utilities last week announced it has hired Crystal Pruitt, effective

Nov. 23, as the deputy director for Clean Energy Equity, where she will be tasked with "ensuring that New Jersey's clean energy future is accessible to all residents."

According to the board, filling the new role is the first step in developing its Office of Clean Energy Equity, which will oversee the equitable deployment of clean energy technologies and energy efficiency programs. BPU President Joseph Fiordaliso announced his intention to create the role in June.

Pruitt joins the BPU after serving as chief of staff for Assemblyman Andrew Zwicker, where she focused on energy issues.

More: *New Jersey BPU*

OHIO

Cincinnati, Columbus Sue to Block Nuclear Bailout Fees

Cincinnati Mayor **John Cranley** and Columbus City Attorney Zach Klein last week filed a lawsuit seeking a court injunction blocking the state's $1.3 billion nuclear bailout fee, set to hit residents' electric bills on Jan. 1, alleging it is an "unconstitutional tax" because it is based on fraud.

Without legal or legislative action, an 85-cent/month fee will be added to residential bills to subsidize two nuclear plants owned by Energy Harbor, which was previously FirstEnergy Solutions. The change is part of House Bill 6, which was passed last year to bail out the plants.

Former House Speaker Larry Householder and four others were arrested and accused of accepting nearly $61 million in bribes from "Company A," believed to be FirstEnergy, and other businesses to win control of the House of Representatives, pass the bailout and defend it. On Thursday, FirstEnergy fired its CEO, Charles Jones, over his role in the bribery scheme. (See related story, *FirstEnergy Fires Jones over Bribe Probe*.)

More: *Cincinnati Enquirer*

UTAH

EPA Approves State Pollution Controls at Power Plants

EPA last week approved a plan for new pollution controls on PacifiCorp's Hunter and Huntington coal-fired power plants in Emery County aimed at reducing haze near two national parks.

The agency said the plan calls for providing credits for nitrogen oxide emission-control systems at the plants. It also said it was formally withdrawing a mitigation plan for the two plants it had submitted under the Obama administration in 2016.

Despite the announcement, the Healthy Environment Alliance said the plan does not do enough to curb emissions and will have no effect on cleaning the state's air.

More: *The Associated Press*

VIRGINIA

Shenandoah County Approves Solar Facility Permit

Shenandoah County supervisors last week unanimously approved a special-use permit to allow a large-scale solar generating facility to be constructed on 32 acres of land in Mount Jackson.

Randolf Solar Partners originally filed the special-use permit with the intent of constructing the facility on land adjacent to an existing Shenandoah Valley Electric Cooperative substation. Chris Gordon, a developer with EDF Renewables Distributed Solutions, told commissioners and supervisors earlier this month that all power generated from the facility would go directly to county customers.

The site will have a lifespan of 25 to 35 years and could be up and running by the second or third quarter of 2021.

More: *The Northern Virginia Daily*

WISCONSIN

Green County Wind Farm Scrapped

EDF Renewables, which was planning on building a 24-turbine wind farm in Green County, notified landowners last week that it would be terminating its lease agreements. The 65-MW farm would have been the sixth-largest in the state.

Sandi Briner, vice president of corporate communications for EDF, confirmed the project had been canceled but did not disclose why.

More: *Wisconsin State Journal*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