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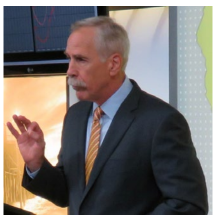
CAISO Narrowly Avoids Blackouts amid Brutal Heat, Fires

Demand Response, Conservation Headed off Another Crisis

By Hudson Sangree

In the face of another heat wave and raging wildfires, CAISO avoided rolling blackouts but declared Stage 2 emergencies on Saturday and Sunday after losing transmission and generating capacity without warning.


Eric Schmitt, CAISO | © RTO Insider

Sunday was "undoubtedly the most stressful grid day we had this year, maybe 10 years," Vice President of Operations Eric Schmitt said in a media briefing Monday.

At midday Sunday, the ISO said it faced a 4,000-MW "mismatch" between supply and demand and could order rolling blackouts affecting millions of residents unless massive conservation efforts and aid from neighboring utilities allowed it to avert or limit outages.

If that had happened, it would have been the second time in less than a month that CAISO resorted to rotating outages to avoid jeopardizing the Western grid. The blackouts of Aug. 14-15, which affected more than 1 million customers, were the first time the ISO used its emergency powers in nearly 20 years. (See *Theories Abound over California Blackouts Cause*.)

A heat wave set record or near record temperatures across the West on Sunday, including 109 degrees Fahrenheit in downtown Los Angeles and 113 F in Las Vegas. Wildfires raging in Central and Southern California took transmission lines out of service, stranded

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High Fire Danger Prompts First Oregon PSPS Event (p.11)

Montana Hybrid Ruling Departs from PURPA Precedent

By Robert Mullin


| © RTO Insider

FERC last week broke with precedent in a decision that will hamstring the ability of renewables-plus-storage developers to optimize the output of their projects while still qualifying for treatment under the Public Utility Regulatory Policies Act.

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FERC Rejects NYISO Bid to Aid Public Policy Resources

Glick: Ruling will 'Doom' ISO's Capacity Market

By Rich Heidorn Jr.

FERC on Friday rejected NYISO's proposal to make it easier for public policy resources to clear its capacity market, prompting a fiery dissent from Democrat Richard Glick, who warned the ruling "will ultimately doom NYISO's current capacity market construct by forcing New York to choose between the commission's constant meddling and the state's commitment to addressing the existential threat posed by climate change."

Chairman Neil Chatterjee and fellow Republicans James Danly and Bernard McNamee — in one of his final rulings before leaving the commission — joined in rejecting the proposal, which would allow public policy resources in New York City and capacity zones G-J to avoid buyer-side mitigation if enough existing capacity exits the market, or if demand increases enough to boost capacity requirements (*ER20-1718-001*).

The proposal was recommended by NYISO's Independent Market Monitor and supported by majorities of all of the ISO's stakeholder sectors. (See *Five New Recommendations from NYISO Monitor*.)

'Similarly Situated'

But the commission majority said NYISO's plan was "unduly discriminatory because it does not provide sufficient justification for prioritizing the evaluation of public policy resources before nonpublic policy resources, independent of cost."

The ISO contended public policy resources — renewables, battery storage and other zero-emission resources — are not "similarly situated" to nonpublic policy resources because the latter are unlikely to be completed under New York's aggressive emission-reduction goals.

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In this week's issue

FERC/Federal News

McNamee Leaves FERC

Panel Reduced to 3 Members Pending Confirmation of Christie, Clements

By Rich Heidorn Jr.

FERC Commissioner Bernard McNamee bid farewell to the commission last week after a 21-month term during which the panel's bipartisan traditions were tested as perhaps never before.

McNamee, a Republican whose term as replacement for former Commissioner Robert Powelson expired on June 30, announced in January that he would not seek a second term but agreed to remain on the commission pending his replacement. His last day was Friday.

President Trump announced McNamee's replacement, Virginia State Corporation Commission Chair Mark Christie, in July. McNamee's departure reduces the panel to three members pending the confirmation of Christie, a Republican, and clean energy activist Allison Clements, a Democrat. Clements would fill the seat left vacant by Cheryl LaFleur, who departed in August 2019. (See *Trump to Nominate Christie, Clements to FERC*.)

McNamee, a former aide to Sen. Ted Cruz (R-Texas), was serving as executive director of the Energy Department's Office of Policy when he was tapped by Trump.

He was barely confirmed, 50-49, on a party-line vote. Democrats' opposition to McNamee stemmed in part from his role in drafting DOE's Notice of Proposed Rulemaking seeking subsidies for endangered coal and nuclear generators.

Sen. Ted Cruz (R-Texas) introduces his former aide Bernard McNamee, President Trump's nominee to FERC, before the Senate Energy Natural Resources Committee.| © *RTO Insider*

FERC Commissioner Bernard McNamee gives his opening remarks at his first open meeting in December 2018. | © *RTO Insider*

He also worked briefly as the director of the Texas Public Policy Foundation's Center for Tenth Amendment Action, a group that files legal challenges over what it views as federal government overreach. It was in this role that McNamee promoted the center's Life: Powered initiative — described as a project to "reframe the national discussion" about fossil fuels.

McNamee described the effort as "the key not only to our prosperity [and] quality of life, but also to a clean environment" and attacked environmental groups, describing their activism against fossil fuels as a "constant battle between liberty and tyranny."

McNamee did not use such polarizing language after joining the commission. But he joined his fellow Republicans — Chairman Neil Chatterjee and since March, James Danly — in repeatedly vexing Commissioner Richard Glick, the lone Democrat since LaFleur's departure.

While LaFleur had joined with the Republican commissioners in approving multiple natural gas pipelines and LNG export facilities, Glick has opposed them, contending the commission is violating the law by not considering the impacts of greenhouse gas emissions from the projects. Glick and the Republicans also clashed over commission orders that frustrated state emission-reduction policies. (See related story, *FERC Rejects NYISO Bid to Aid Public Policy Resources*.)

McNamee reflected on his term on the commission in a FERC Open Access *podcast* recorded shortly before his departure.

He said he was surprised by the volume of orders the commission issued — 941 in 2019 and more than 700 through August 2020. "For every party that comes before the commission, their issue is the most important. And I try to approach each case that comes before us with that in mind."

He said he was particularly proud of the commission's updates of its rules on return on equity and the Public Utility Regulatory Policies Act and its approval of 14 LNG export facilities.

"Before I got to the commission, for two years, no LNG export facility had been approved. After I got here, I dug into the law and the facts and was able to work with Commissioner LaFleur and the chairman, and we came up with a compromise," he said. "And I think that's something [that] is very good for the American people. With the abundance of natural gas that we have, being able to build those facilities ultimately will result in billions of dollars of investment [and] thousands of new jobs, and it will also give new policy tools to American elected officials in dealing with other countries because of the ability to use American energy in order to help influence events and support our allies and friends."

The commissioner, who has been commuting weekly to D.C. from his home near Richmond, Va., had said he was eager to spend more time with his wife and teenage son. McNamee said he plans to take some time off before looking for his next job. "I expect that I'll continue to work on energy issues from both legal and policy perspectives," he said. ■

FERC/Federal News

Expert Says Nuclear's Future Lies in Small, Mobile Reactors

By Amanda Durish Cook

Small, dispersed reactors are the nuclear industry's best chance at future success and can forge a quicker path to zero-carbon electricity portfolios, one nuclear energy policy expert told her audience last week.

Jessica Lovering, Carnegie Mellon | *Resources for the Future*

Carnegie Mellon University researcher Jessica Lovering on Sept. 1 said the industry is making strides on small modular reactors (SMRs), light-water reactors, molten salt reactors, helium-cooled fast reactors and micro reactors. Those advancements could prove a renaissance for the nuclear industry, she said during a webinar on advanced nuclear technologies hosted by environmental policy nonprofit Resources for the Future.

Lovering said the first-ever small modular reactor is close to commercialization. Portland, Ore.-based NuScale Power's SMR design last month passed the U.S. Nuclear Regulatory Commission's final review for design certification. NuScale said customers can now proceed with plans to develop their power plants. (See *NRC OKs NuScale's Small Modular Reactor Design*.)

Micro reactors have much longer core lifetimes that can operate up to 30 years between refueling, Lovering said, and some advanced technologies come equipped with a lifetime core.

Other reactors can be designed so that the cores are already fueled when shipped from factories, Lovering said. When those reactors reach the end of their lifespan, she said, they can be packaged and sent back for either refueling or decommissioning.

"You ship the whole reactor back, and that's good for communities that don't want to deal with the whole refueling and decommissioning process," she said. "This can really open up new markets in communities. … The waste won't sit on site. It'll go back to a central facility. Of course, that still leaves what the central company will do about disposal."

Lovering said there's much research and development on waste disposal and processing that is yet to be tackled.

Most small reactors have sealed cores to prevent access to the nuclear material, minimizing the risk of accidents or terrorism, she said. Lovering also said molten salt retains its liquid form even at very high temperatures, minimizing explosion danger.

Artist's rendering of NuScale Power's small modular nuclear reactor plant | *NuScale*

"It's really going to be up to proving the safety case to the regulators," she said.

Lovering said nuclear capacity has stagnated in the U.S., hovering around 20% of generation since the 1990s. That share is at risk of retirement as electrification boosts energy demand, she said. More nuclear capacity should come online beyond the two plants under construction in Georgia, she argued.

The International Energy Agency estimates that global nuclear capacity needs to *double* by 2050 to meet aggressive carbon-reduction goals.

"Some of the big obstacles to building new nuclear … are really high cost and long construction times," Lovering said. "They're too big and expensive for deregulated markets."

She said it's no surprise that the only two new plants in construction, Georgia Power's two additional units at *Plant Vogtle*, are in the regulated southeastern U.S. The Vogtle expansion has nearly *doubled* in price from the original $14 billion the Georgia Public Service Commission approved more than a decade ago. Last week, Georgia Power told the PSC that the project is on schedule, with the first unit set to go online in November 2021 and the second to follow a year later.

Lovering also noted that some states have moratoriums on new nuclear generation until the national waste disposal problem is addressed.

Communities with coal-fired plants set to retire in the next decade could be an ideal fit for a small nuclear reactor placed on the plant's site, Lovering said. That would retain some jobs, she said, as even small, dispersed nuclear reactors will need staff.

"You can take advantage of the existing coal plant site and power lines," she said, adding that some coal plant employees could be retrained to staff the reactor.

Micro reactors can also be installed to provide emergency services on existing grids, keeping hospitals and other essential services running in a blackout, she said.

Lovering also said it's important to prolong the operation of existing nuclear plants for as long as they are safe and not let economic forces compel early retirements. She said as nuclear plants are decommissioned before their useful life ends, they lose their spot in the public consciousness as a viable option for zero-carbon energy resources.

"It's a real shame to close any of them early. What we see is when they're shut down, they're often replaced with natural gas," she said.

Lovering said the *Nuclear Energy Leadership Act*, introduced in Congress last year, could spark more industry growth. The bill would provide funding for two advanced nuclear reactor demonstration projects by 2025 and up to five such projects by 2035.

Talk of a Green New Deal in Congress has fostered an openness to new nuclear capacity, she added.

"That's really driven by the reality on the ground," Lovering said, noting that wind and solar generation continue to have a variability problem that needs solving. ■

CEC Explores Building Design Role in Decarbonization

By Robert Mullin

Smart building design can play a central role in California's drive to decarbonize its electricity system, but the massive stock of existing structures cannot be left out of the effort.

That was a key takeaway from a panel discussion Wednesday, part of the California Energy Commission's two-day forum on "Reimagining Buildings for a Carbon Neutral Future."

"Decarbonizing our built environment is an opportunity to improve the relationship that our buildings have to the grid," said Commissioner Andrew McAllister, the panel moderator.

But McAllister said he needed to "dispatch" one timely topic before kicking off the panel: "Our decarbonization goals were not the underlying reasons for" the rolling blackouts that shut power to millions of Californians during a mid-August heat wave. (See *CAISO Provides More Details on Blackouts*.)

Instead, the supply shortages prompting the Aug. 14-15 blackouts were caused by "momentary issues regarding weather" and California's inability to import power from other Western states suffering under the same record-setting heat, McAllister said. (See *Theories Abound over California Blackouts Cause*.)

"It was really the reserve capacity that was not available when it was expected to be there," he said. "The system actually mobilized new resources" during the system emergency.

McAllister's defense of California's ambitious environmental goals provided a transition into the theme of the panel: "Our buildings can be a decarbonization resource for the grid," he said.

Buildings can be modified to "help in an aggregated way" to support grid reliability through load flexibility, demand response and use of distributed energy resources, McAllister said. He cited the example of OhmConnect, a DR provider that works with residential customers of Pacific Gas and Electric and Southern California Edison that helped stave off additional blackouts over Aug. 17-18 by calling on 250 MW of aggregated energy reductions.

"They have relationships with individual residential customers, and it's a bidirectional, callable, fairly predictable resource at this point," he said.

"How our buildings actually consume energy and how they behave is a topic of our time, and we will be in the coming months and years getting deep into that and developing resources to help that happen at scale," McAllister said.

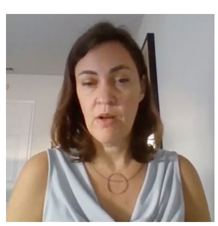

Andrew McAllister, CEC | *California Energy Commission*

New and Old

New construction tends to dominate discussions around green building. McAllister asked his panelists to consider how existing buildings will represent the majority of structures needing decarbonization by midcentury, which in California will mean the electrification of appliances that still largely run on natural gas, such as furnaces, water heaters and stoves.

"Not that fully decarbonizing new construction is easy, but I think that it's a different challenge and probably has fewer facets to it than our existing buildings," he said.

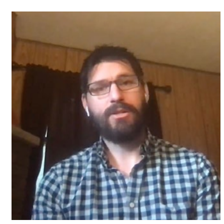
McAllister pointed to one of those facets: that California's most diverse populations live in existing housing stock, inserting a social and racial equity angle into the policy of decarbonizing housing.


Heather Rosenberg, Arup | *California Energy Commission*

"Certainly, anything that's new should be held to the highest standard," said Heather Rosenberg, an associate principal at sustainability consultant Arup. "That said, the places where there is most significant need is in existing buildings ... particularly buildings in low-income communities and affordable housing."

Rosenberg pointed to the difficulty of addressing decarbonizing homes in areas with low-income housing that have long suffered from "chronic" disinvestment.

"As we think about that and as we think about our communities, there is an opportunity to bring investment in and make sure that it's done for the people who are in those communities without triggering further displacement and further degradation in places that really are requiring investment," Rosenberg said.


Shawn Hesse, International Living Future Institute | *California Energy Commission*

"Some of our biggest projects that have pursued certification and used our platforms are renovation projects," said Shawn Hesse, director of business development at the International Living Future Institute, which certifies structures that meet green standards.

"The question we pose all the time is [that] we're not interested in something that's a little less bad; we want to know what's good," Hesse said. "What does good look like? And you can ask that question for renovation projects as well."

"I think we're uniquely positioned here in California to have greater influence and impact on decarbonization, whether it's existing or new buildings," said Miranda Gardiner, senior vice president with design firm HKS. "We have Silicon Valley; we have so many higher [education] institutions — the [University of California] campuses that marry their new and existing construction with their master plans."

CAISO/West News

Miranda Gardiner, HKS | *California Energy Commission*

Gardiner said she appreciates working with clients such as universities and health care providers because "they're not into this kind of fast-fashion approach that some of our developer clients are, and they know their buildings are going to be operational/functional [and] they're going to have occupants in them for the next 50 years, and they're thinking about it long-term."

"And when they look at their existing stock, [they ask the question], 'How do I bring that up to speed with the new buildings?'" she said.

McAllister asked the panel how the building industry can attract financing for decarbonized buildings and appeal to investors that recognize the value of "co-benefits" from greater building efficiencies. Those benefits can include lower expenses, better indoor air quality and the livability improvements from an overall higher standard of design.

Rosenberg said Arup is currently working with a major nonprofit developer of affordable housing to create metrics for co-benefits in a way that could drive investment from socially conscious investors.

"And then you have to think about how to bundle projects, because at the individual project level, it's not enough to attract investment. You need a bunch of them, and then what's the [return on investment]?" she said.

"We aren't missing the technology. We aren't missing the recognition of the climate imperative," Hesse said. "What we're missing is the ability to align the financing with these projects to actually turn them into reality."

Rosenberg said the economic signals for decarbonization will not be strong enough until there's a "real" price on carbon, which will likely require a "regulatory push."

None of the panelists could answer McAllister's question about what carbon price would actually "flip the switch" and bring investment into building decarbonization.

"We really need to … unpack that," McAllister said.

Decentralized Resilience

Decarbonization is currently seen as "mitigation strategy" for climate change, but it can move beyond that role to reshape the relationship between the built environment and the electricity grid, Rosenberg said.

"It also can become, if we design it right, an adaptation strategy where we are reducing our dependence on a completely centralized and fairly rigid grid and bringing diversity, flexibility, durability [and] redundancy into our energy system in some new and creative ways. But it only works if you design it that way," Rosenberg said.

The California utility policy of public safety power shutoffs (PSPS) to avoid sparking wildfires "has changed the way that people think about power reliability," she said. PSPS is driving interest in microgrids by businesses such as airports, hospitals and data centers, for whom the momentary switching to backup power is too disruptive.

While those organizations previously couldn't justify the cost of a microgrid based on the benefits of having flexible load or providing DR, the value of having "constant power" now makes the idea "pencil" out — "and that's been a really big shift in the state," Rosenberg said.

Hesse echoed the theme of reducing dependence on a centralized grid, offering a different take on the notion of resilience.

"As great as new technology is, and the ability to do instantaneous demand shifting, there are some pretty basic things that allow us to design projects to need less energy in the first place," Hesse said.

He recounted a story about a project team from his company meeting in a "living" — or sustainably designed — building when the grid went down.

"No one noticed," he said, because the building was designed based on passive energy principles, being primarily lit by daylight and having a natural ventilation system.

"When it does need those active systems, those systems are powered through on-site renewables," Hesse said.

"Designing out the reliance on those kinds of systems is kind of the primary resilience strategy that allows us to do so many things all at once," he continued. "I don't want to leave that out of the conversation — that there's actually a huge role to play in terms of the design community, particularly, in really doing our own best practice and not relying so much on grid administrators." ■

CAISO/West News

CAISO Narrowly Avoids Blackouts amid Brutal Heat, Fires

Demand Response, Conservation Headed off Another Crisis

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hydroelectric and solar resources and fouled the air in major cities.

On Saturday evening, the ISO suddenly went from an energy warning to a Stage 2 emergency when fires near Fresno and in Southern California interrupted power flowing from a hydroelectric plant in the Sierra Nevada foothills and solar arrays in the Imperial Valley, said John Phipps, director of real-time market operations.

The fires cut off 1,600 MW, forcing CAISO to an emergency status that allowed it to borrow 300 to 400 MW each from the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD). Blackouts were narrowly averted.

About 600 MW of the lost power returned Sunday, Phipps said, but in the middle of the briefing, he said he had just learned another 500 to 600 MW had been lost because of fire at a plant.

Sunday's peak demand was projected to exceed 49 GW, by far the highest load of the year, but it ended up being slightly more than 47 GW, still a record high for 2020, Schmitt said. Neighboring states struggling with the heat didn't have much electricity to spare, he said.

On Sunday, Schmitt warned that when California's solar power waned in the evening while demand remained high, severe shortfalls would occur. "We still haven't been able to find enough energy to make up that shortage," he said.

During the mid-August heat wave, Nevada's NV Energy strained to serve load, especially in the Las Vegas area, and issued emergency alerts.

On Friday, FERC granted PacifiCorp temporary authority to make short-term sales of electricity to NV Energy during emergency conditions at CAISO's 15-minute market LMP at the Palo Verde price node (ER20-2816). The sales would otherwise be prohibited by PacifiCorp's tariff.

"Due to credible information about possible reliability problems, we find that the exercise of our discretion to grant this waiver in part is warranted," FERC said.

Events of Sept. 6

CAISO predicted problems to start around 5 p.m. Sunday and grow worse until as late as 10 p.m. There was a 4,000-MW difference between forecasted supply and demand at 1 p.m.

Unless circumstances changed, CAISO said it would likely declare a Stage 2 emergency between 4 and 5 p.m. and move to a Stage 3 emergency, commencing blackouts, around 5 p.m., Schmitt said. Outages could have affected 2.5 million to 3 million customers, or about 7.5 million to 9 million residents based on average household size.

The Stage 2 emergency was declared later than expected at 6 p.m., when a high-voltage DC line linking California to Oregon was suddenly derated by 1,100 MW and adjacent AC lines became overloaded, causing CAISO to lose 1,600 MW in minutes, Phipps said.

Then a 260-MW generating resource tripped offline. Having lost 1,900 MW, CAISO was "close to the edge," Phipps said.

It called on large-scale consumers to honor their demand-response contracts and limit consumption, taking 960 MW of load off the system, he said. LADWP and SMUD again supplied additional power, while residents did their part to conserve, he said.

CAISO did not have to progress to a Stage 3 emergency.

The weather forecast called for a cooling trend starting Monday but also high winds that Pacific Gas and Electric and other investor-owned utilities warned could lead to public safety power shutoffs (PSPS) to prevent wildfires. CAISO said it did not expect the PSPS events to impact its system. ■

Triple-digit heat across much of the West is straining CAISO's system.

CAISO/West News

OTC Plants to Remain Open, Calif. Water Board Rules

By Hudson Sangree

Four aging natural gas plants scheduled to retire in December will keep operating because of California's anticipated capacity shortfall, state water officials decided last week.

The four members of the State Water Resources Control Board on Sept. 1 voted unanimously to reverse a prior board decision ordering the once-through-cooling (OTC) plants to cease operations by the end of this year, saying they are needed for grid reliability.

"This decision doesn't come lightly to us as board members," Chair E. Joaquin Esquivel said. But "there was always the understanding that we needed to balance [environmental concerns with] grid reliability."

Last week's ruling allows selected units at the Alamitos Generating Station in Long Beach, the Huntington Beach Generating Station in Orange County and the Ormond Beach Generating Station in Oxnard to operate for three more years, until Dec. 31, 2023. The Redondo Beach Generating Station in Los Angeles County got a one-year reprieve to Dec. 31, 2021.

The Alamitos (1,200 MW), Huntington (250 MW) and Redondo (850 MW) plants are owned by AES California. The Ormond plant (1,500 MW) is owned by GenOn.

The OTC plants use ocean water for cooling, killing billions of marine organisms, the water board found. In 2010, it ordered the phase-out of 19 OTC plants along the coast. Some plants retired, while others updated to air-cooling or alternative water-cooling technologies. The last four plants, built in the 1950s and 1960s, still use their original cooling designs.

The hulking plants loom over densely populated coastal communities, wetlands and sandy beaches. Many residents and elected officials want them closed because they are noisy, polluting and unsightly. Dozens spoke at the Sept. 1 meeting, encouraging the board to adhere to its original plans.

However, the California Public Utilities Commission projected capacity shortfalls of 2,300 to 4,400 MW starting in the summer of 2021 and extending through 2023. Last year the commission *ordered* utilities to collectively procure 3,300 MW by August 2023, with 50% to come online by August 2021 and 75% by August 2022. It also recommended the water board extend the OTC compliance deadlines. (See *California PUC Votes to Keep Old Gas Plants Operating*.)

The three organizations that oversee energy in California — the CPUC, CAISO and the state Energy Commission — urged the water board to let the plants remain open until the new capacity could come online.

"These compliance date extensions would provide a bridge of about 3,740 MW in 2021, 2,230 MW in 2022 and 1,380 MW in 2023," board staff said in their report.

California is on an ambitious course to supply 100% carbon-neutral energy to retail customers by 2045. It has ample solar generation but still needs thousands of megawatts of battery storage to let solar meet evening demand.

With fossil fuel generation retiring across the West, the OTC peaker plants help the state meet high demand on hot summer evenings after solar generation falls away. The rolling blackouts of Aug. 14-15 occurred under such conditions. (See *CAISO Provides More Details on Blackouts*.)

The board on Sept. 1 also voted to amend the retirement dates of the Diablo Canyon Nuclear Power Plant, California's last nuclear generating station. It extended Diablo Canyon Unit 2's closing date for eight months to August 2025 and shortened Unit 1's retirement date by two months to November 2024.

"These revisions match the expiration date of each unit's Nuclear Regulatory Commission operating license, as requested by the Pacific Gas and Electric Co. as part of its plan to retire Diablo Canyon," the board said in a written summary. ■

Alamitos Generating Station | *California Energy Commission*

CAISO/West News

Montana Hybrid Ruling Departs from PURPA Precedent

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The commission's lone Democrat, Richard Glick, sharply dissented from the Sept. 1 ruling, which found that the 210-MW Broadview Solar hybrid project in Yellowstone County, Mont., cannot be certified as a PURPA qualifying facility because it exceeds the 80-MW cap on power production capability specified in the 1978 law. The commission found the project exceeded the cap despite the 80-MW limitation on its interconnection with the NorthWestern Energy transmission system (QF17-454).

Montana has been an especially contentious front for PURPA disputes in the West, where utilities contend the law requires them to integrate large volumes of QF renewable resources at contracted rates far above market rates. Montana's Supreme Court last month ruled that the state's Public Service Commission had "arbitrarily and unlawfully" reduced solar generators' payments and contract lengths under PURPA. (See *Montana Supreme Court Rebuffs PSC on PURPA*.)

Broadview, a subsidiary of Broad Reach Power, stepped into the PURPA fray last year when it revised its QF application to reflect a gross capacity of 160 MW (up from 104.25 MW in the original 2016 application) and include 50 MW of energy storage, while maintaining a net capacity of 80 MW.

FERC noted the company explained that while its planned solar array "is sized greater than 80 MW to increase the facility's capacity factor, the aggregate capacity of the solar array and battery storage system cannot exceed 80 MW net capacity due to" limitations on the project's DC-to-AC inverters. Broadview said the increased power is not in a form to be transmitted to the grid without additional inverters.

The company contended that FERC's finding in 1981's *Occidental Geothermal, Inc.* that "a facility's power production capacity is not necessarily determined by the nominal rating of even a key component of the facility" backs up its claim that the solar facility falls within the 80-MW limit.

Broadview also pointed to FERC's determination in *Malacha Power Project, Inc.*, a 1987 ruling that said that "the electric power production capacity of the facility is the capacity that the electric power production equipment delivers to the point of interconnection with the purchasing utility's transmission system."

NorthWestern contested Broadview's application, arguing that facility is not a single QF, putting it outside PURPA's 80-MW capacity limit. It said the solar array and battery storage system are two distinct power production facilities at the same site because the 160-MW solar array exceeds the 80-MW net capacity limit and the battery qualifies separately as a small power QF.

The utility questioned Broadview's interpretation of *Occidental*, contending that a facility's individual components represent the most relevant calculation of its net capacity and that *Occidental* had actually determined that a facility could qualify as a QF only if it has the potential to produce more than 80 MW for limited periods because of circumstances outside the facility's control.

The Edison Electric Institute argued that FERC should not allow generation operators to "artificially limit" the output from their facilities at a single location to stay within the 80-MW limit.

"With the growth of new technologies, such as batteries, and the increased sophistication of resources, EEI asks the commission to reconsider whether it is still appropriate to measure QF power production capacity based on net capacity as established in *Occidental*, rather than the rated capacity test that EEI asserts was initially intended by Congress," FERC noted.

Occidental Reversal

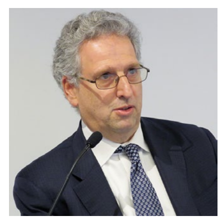
FERC's decision aligned with the complaints made by NorthWestern and EEI. While the commission acknowledged that its 40-year-old *Occidental* decision specified that a facility's "send out" capability — and not the size of the project's individual components — was the determining factor for PURPA eligibility, it now finds "there is a significant difference between (i) design capabilities that may incidentally or occasionally cross PURPA's 80-MW threshold due to certain components or variances, such as fuel or ambient temperature, and (ii) a facility purposefully designed with a 160-MW solar array."

"Broadview's proposal represents a significant departure from any project that the commission has previously considered under a QF application," FERC wrote. "That such a project arguably could satisfy the 'send out' analysis the commission applied in *Occidental* compels us to reconsider whether it is a facility's 'send out' that is determinative of whether the facility complies with the 80-MW threshold established in PURPA."

Based on that reconsideration, the commission determined that the *Occidental* finding that the maximum net output of the facility (or send-out) represents the facility's power production capacity is inconsistent with the 80-MW power production capacity limit specified by PURPA and regulations.

"Re-examining *Occidental* and the potential such an analysis creates for the approval of projects that do not comply with the plain language of PURPA, we conclude that we have improperly focused on 'output' and 'send out,' instead of on 'power production capacity,' which is the standard established both in the statute and our regulations," the commission wrote.

'Preferred Outcome'



FERC Commissioner Richard Glick | © *RTO Insider*

In his dissent, Commissioner Glick said that any "fair reading" of the PURPA statute and commission precedent would put Broadview's power production capacity at 80 MW and make it eligible for QF status.

"The commission's contrary determination will make QF status turn on the capacity of any one component of the facility, rather than the actual power production capacity of the facility itself. That conclusion finds no support in the statute, our precedent or common sense," Glick wrote.

Glick agreed with Broadview that increasing the project's power production capacity worked to improve its capacity factor, "meaning that the facility will, all else equal, generate a higher fraction of its total 80-MW capacity than it would with a smaller array … a result I would have thought the commission would be eager to encourage."

He further called out the commission for a "break from precedent" that reaches "its preferred outcome."

"On a broader level, I cannot help but express my concern that so casually upending settled precedent creates unnecessary uncertainty, making it hard for developers to know which precedents they can count on and which they cannot," he said. ■

CAISO/West News

Study: Calif. Must Build Renewables at Record Rate

Huge Amounts of Solar, Wind and Storage Needed to Reach 2045 Zero-carbon Goal

By Hudson Sangree

California must build generating resources at an unprecedented pace to reach its goal of supplying 100% renewable and zero-carbon energy to retail customers by 2045, according to the draft results of a study released last week.

Senate Bill 100, signed by Gov. Jerry Brown in 2018, established the landmark clean-energy mandate and required the California Energy Commission (CEC), Public Utilities Commission and Air Resources Board to report to the State Legislature by Jan. 1, 2021, on factors such as technologies, transmission and reliability.

A joint agency *workshop* Wednesday focused on draft modeling results developed by CEC staff and consultants from Energy and Environmental Economics. Key takeaways from the modeling included a finding that "sustained record-setting build rates will be required to meet SB 100," said Liz Gill, an electric generation system specialist with the CEC, who presented the draft results.

Over the past 10 years in California, developers built an average of 1 GW of solar generation and 330 MW of wind generation each year, Gill said. Battery storage had a negligible yearly "build rate" over the same period, though about 1,000 MW is now installed, she said.

Reaching SB 100's goals by 2045 requires roughly tripling the construction of wind and solar generation and dramatically increasing battery capacity, Gill said. The modelers estimate the state needs an annual build rate of 2.7 GW of solar, 2.2 GW of storage and 1 GW of wind each year over the next 25 years, she said.

However, the build rate will probably gradually increase through 2030, with the state "playing catchup" and building resources at a much faster clip from 2030 to 2045, she said. (The state is required to hit a 60% renewable portfolio standard by 2030.)

Under a "high electrification" scenario, with consumers switching from gas to electric appliances, the state must add 180 GW of new capacity, including 70 GW of utility-scale solar and 50 GW of storage to reach SB 100's goals, Gill said. The land required for so much wind and solar is substantial. Solar projects alone could occupy nearly 500,000 acres, Gill said.

The study assumes utility customers will install 39 GW of rooftop and on-site solar by 2045. Wind, including new sources of out-of-state wind and offshore wind in California, will make up the additional 20 GW, the analysts forecasted. ■

California needs an additional 70 GW of utility-scale solar to reach its clean-energy mandate. | *U.S. Department of the Interior*

CAISO/West News

High Fire Danger Prompts First Oregon PSPS Event

By Robert Mullin

Portland General Electric on Monday pre-emptively cut power to about 5,000 customers in high-risk fire areas near Mount Hood in the first public safety power shutoffs (PSPS) to affect Oregon residents.

The utility began cutting service on Monday evening to prevent its equipment from sparking wildfires along a heavily forested portion of U.S. Route 26, stretching from Alder Creek to the high-elevation town of Government Camp, southeast of Portland.

"The proactive safety outage is a last resort to help protect people, property and the environment in the fact of extreme fire danger conditions and high winds forecast for the area," PGE said in a statement.

PGE said it expected the distribution outages to last from 24 to 48 hours, "subject to repair times for any damage that may occur."

The shutoffs coincided with a small wildfire that burned about 2 acres near the Mount Hood Meadows ski area on the south side of the mountain, shutting down nearby hiking trails. The cause of that blaze, which occurred away from any power lines, was still under investigation.

On Monday, Mount Hood and its foothills were shrouded in a thick haze as high winds carried in smoke from larger fires burning to the east. With winds expected to gust as high as 65 mph, a red flag warning is in effect for the Mount Hood National Forest through Wednesday evening, indicating an increased danger of wildfire.

While PSPSes have become increasingly commonplace during California's growing wildfire seasons, the practice is new to the Pacific Northwest.

"Even in historically wet, mild Oregon, summers are getting hotter and dryer with longer wildfire seasons, and the overall risk of wildfires is increasing," PGE said.

The utility said it is taking other steps to prevent wildfires in its service territory, including increased vegetation management and inspection along its 12,000 miles of power lines and replacement and modification of equipment to reduce the risk of sparking fires.

PGE said it is also training crews in basic firefighting to learn "what to do if a fire ignites at their work scene" and "help prevent it from escalating to an even more dangerous situation."

Portland-area Outages Top 100,000

Monday evening also saw more than 100,000 Portland-area customers of PGE and Pacific Power lose power as high winds with gusts as high as 55 mph snapped tree limbs and knocked down distribution lines throughout the region. An additional 15,000 PGE customers in Marion and Yamhill counties south of the metro area also lost service.

Even as PGE crews restored service to customers, the utility's website showed outages continuing to climb throughout Monday night and into the early morning hours today.

The high winds are expected to persist throughout the region into midweek as a late-summer heat wave pushes temperatures into the mid-90s. Milder conditions are in the forecast for later in the week, according to the National Weather Service. ■

Mt. Hood National Forest was shrouded in smoke Monday as high fire danger in the area prompted PGE to invoke Oregon's first public safety power shutoffs. | © *RTO Insider*

ERCOT News

ERCOT Reports Adequate Capacity for Fall

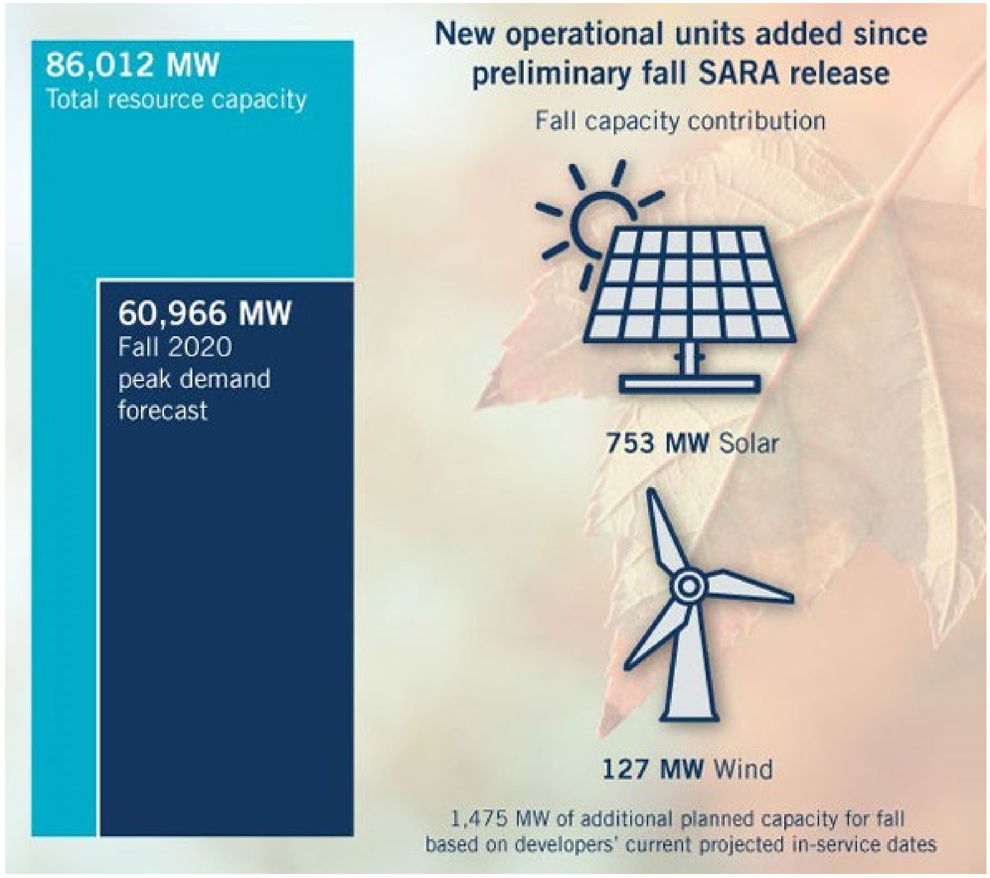
ERCOT said Wednesday it expects "adequate" installed capacity available to meet demand this fall and winter.

The grid operator's final *seasonal assessment of resource adequacy* (SARA) for the fall forecasts a peak demand of nearly 61 GW, unchanged from the preliminary fall forecast. It expects it will have more than 86 GW of capacity available. That takes into account a generation-outage projection of 14.3 GW, based on the historical average of outages for weekday peak hours during the last three fall seasons.

ERCOT has added 753 MW of solar capacity and 127 MW of wind capacity since the preliminary fall SARA. It also expects another 1.5 GW of planned wind and solar capacity to be online for the fall season (October and November).

"We study a range of normal to extreme scenarios prior to each season to determine whether there are any operational risks associated with meeting the forecasted peak demand," Manager of Resource Adequacy Pete Warnken said in a *press release*. "At this time, our assessments show there will be adequate generation for fall and winter."

ERCOT also released a *preliminary SARA* for the winter (December-February) that includes a peak-demand forecast of 57.7 GW, well below the winter demand record of 65.9 GW set in January 2018.



ERCOT is adding more solar resources than wind resources for the fall. | *ERCOT*

The assessment includes a low-wind scenario that will be used in all future seasonal assessments because of renewables' growth in the ERCOT system. The grid operator reported a shade shy of 25 GW of installed wind capacity and 3.3 GW of installed solar capacity at the end of July, but its *interconnection queue* lists almost 77 GW of solar capacity and more than 25 GW of wind capacity in various forms of study.

Staff developed their peak-demand forecasts for fall and winter using revised Moody's Analytics economic data obtained in April. ■

— Tom Kleckner

ISO-NE News

Overheard at NECEC Back to Work Webinar

The COVID-19 pandemic has roiled the clean energy industry and caused the loss of more than 600,000 related jobs nationwide, and the economic slowdown has also exacerbated social and environmental inequities.

The Northeast Clean Energy Council (NECEC) on Wednesday held the first in a series of *webinars* — called the Clean Energy Back to Work Challenge — which brought together a public official, an environmental advocate and a solar developer to explore how energy infrastructure and policy affect environmental justice and social welfare.

"As we know, clean energy is a key element to the economic recovery and the way out of the recession and economic challenges posed by COVID-19," said Jeremy McDiarmid, vice president of policy and government affairs at NECEC. "We need to make sure that the recovery is just and equitable, and that traditionally disadvantaged populations are getting access to the benefits of clean energy while avoiding the environmental harms associated with fossil generation and pollution."

Following is some of what we heard at the event.

Broad Goals, Public Policy

The clean energy industry now faces three key issues: the environmental justice question, social welfare needs and the intersection of those with public policy on new energy infrastructure, said Kathy Kelly, vice president of operations at Daymark Energy Advisors.

"We have very broad energy goals as a country around decarbonization and the adoption of clean energy and how that fits into our long-term plans," Kelly said. "We need to make sure that as we do that, unlike the past, that all sectors of our society have access to clean energy and are treated equally as we implement the clean energy infrastructure."

The disadvantages from energy development in the past hit poor people worst, which has lessons for overcoming the challenges of today, she said. For example, the housing stock in low-income areas is unable to accommodate renewable energy improvements, whether because of outdated wiring inside, or roofs unable to support solar panels.

It's important not to repeat the mistakes of the past, said John Odell, director of energy and asset management for the city of Worcester, Mass.

Certain parts of the community bear more of the burden than others, which is why the city is developing a Green Worcester *Plan* to serve as a roadmap, he said.

"We want to get as much clean energy out there, remove as much waste from the waste stream, make sure our natural systems are enhanced as best we can and to do as much of that as fast as we can," Odell said. "It's often easier to do those things in areas that don't have the disadvantages, so that's where the issues of social equity come to the forefront. It's easier to build on your strengths than it is to correct your weaknesses."

Environmental Justice and Social Welfare

Health care accounts for more than 10% of greenhouse gas emissions nationally, but the sector also represents about 18% of GDP and is the largest employer in Massachusetts, said Eugenia Gibbons, Boston director of climate policy for Health Care Without Harm (*HCWH*), an international nonprofit organization with a network of more than 1,200 hospitals in the U.S.

"We employ about 500,000 people in the state and the sector also holds a significant amount of real estate across the commonwealth," Gibbons said. "So when hospitals and hospital systems begin to implement climate strategies and try to address climate change in their own systems it's actually having a huge impact on the surrounding communities and on the state as a whole."

The pandemic has reinforced the link between air quality and poor health outcomes, which is now undeniable, she said. Low-income communities and communities of color have been proven more susceptible both to the virus and to the effects of climate change and air pollution.

"They have been ravaged by COVID," Gibbons said. "We have to move away from the impulse to think about climate action as strictly an exercise in reducing GHG emissions, and really try to anchor the work in the communities and anchor the work around people."

The pandemic has caused many disruptions to supply chains, and a combination of the coronavirus and recent protests against racial injustice across the U.S. has "forced a lot of organizations and businesses to have a come-to-Jesus moment and say, 'We're either prioritizing this or we're not,' and a lot of people are making those commitments," Gibbons said. "It's up to everyone to see that they follow through."

Solar development, finance and construction is "pretty resilient," said Jon Abe, CEO of solar finance firm *Sunwealth*, which backs small- and medium-size projects, especially in lower-income communities.

Early on in the pandemic, in many states, solar was deemed an essential service, so while it was complicated, it was relatively easy compared to other businesses to implement the appropriate safety measures at job sites, he said. Sunwealth has almost a dozen developers and installers in the field employing more than 100 electricians and installers at various sites across the U.S.

Sunwealth has been lobbying on low-income community solar inclusion in Massachusetts, where neither the administration nor the legislature has done enough, Abe said. ■

— Michael Kuser

Photos from the June 2019 Worcester Vulnerability Preparedness Plan | *Worcester, Mass.*

ISO-NE News

Consultant to Coordinate New England 'Future Grid' Study

By Michael Kuser and Rich Heidorn Jr.

The New England Power Pool and the New England States Committee on Electricity (NESCOE) are hiring consultant Peter Flynn, a former National Grid executive, to serve as administrator of the Transition to the Future Grid *project*.

Flynn, a former senior vice president and deputy general counsel for National Grid, was introduced Sept. 1 at a joint meeting of the NEPOOL Markets and Reliability committees.

Flynn will report to the committees regularly to ensure the study meets NEPOOL's and NESCOE's goals. The study may be outsourced by ISO-NE or conducted by the RTO with assistance from a consultant.

At the joint meeting, Day Pitney attorney Eric Runge *presented* observations on six past and ongoing studies for their "potential to inform" the Future Grid study. Runge also commented on the proposed scope of the study, which is intended to identify the resource mix needed to meet state climate change goals and gaps in the RTO's ability to reliably operate the grid under the new conditions.

Carissa Sedlacek, ISO-NE's director of planning services, also presented the RTO's preliminary *feedback* on the 10 study proposals submitted for the Aug. 4 meeting. (See *NEPOOL Reviews 'Future Grid' Study Requests*.)

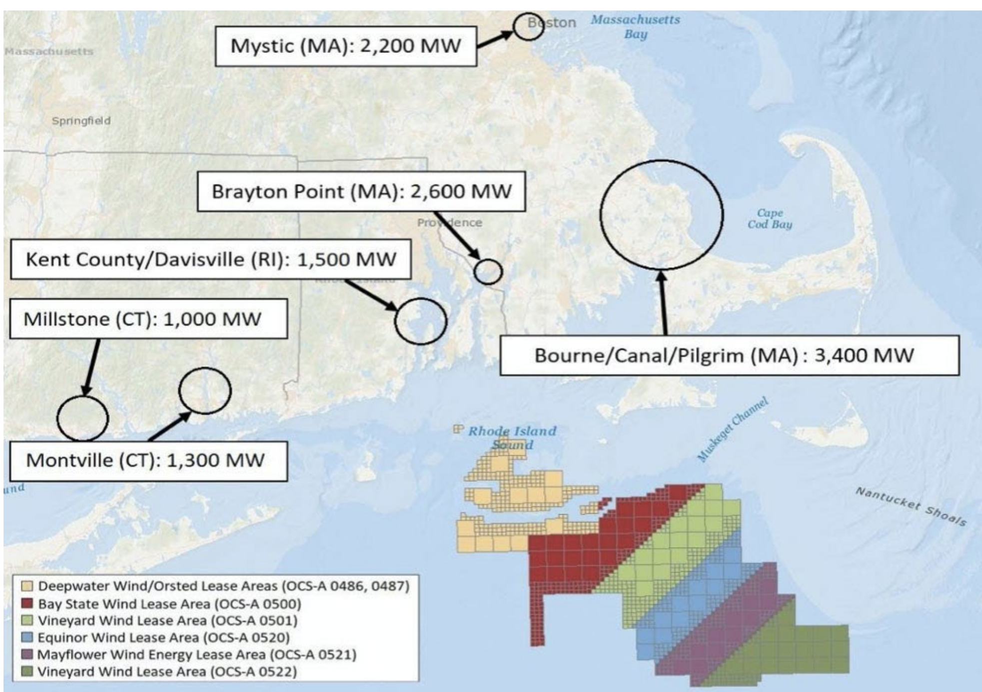
Straw Proposal

Runge said the next step in the process will likely be development of a straw study proposal presented for stakeholders to debate. He reviewed the objectives, scenarios and modeling used for the 2016 NEPOOL Economic *study*; the 2019 NESCOE Economic *study*, as expanded by the Anbaric Development Partners 2019 Economic *study*; the Massachusetts 2050 Roadmap *initiative*; Eversource Energy's "Grid of the Future" *study*; the "Electric Reliability under Deep Decarbonization" *study* by Energy+Environmental Economics (E3)/Energy Futures Initiative (EFI); and Brattle Group's 2019 "Achieving 80% GHG Reduction in New England by 2050" *study*.

Runge said the NEPOOL, Eversource and E3/EFI analyses seem most consistent with the scope of the Future Grid study.

Some of the data, analysis and assumptions from the Massachusetts 2050 Roadmap study and the Brattle study could help establish assumptions and identify gaps because they seem to focus on how to achieve an end-state goal, although both use modeling tools the RTO lacks, Runge said.

The NESCOE study is more limited in scope and would provide only a part of the analysis and information being sought in the Future Grid study, he added.



Interconnection points used for the 12,000-MW OSW scenario in the Anbaric 2019 Economic Study | *ISO-NE*

10 Proposals

Commenting on the study proposals *submitted*, Runge said one from *National Grid* was generally consistent with the scope but has a transmission/storage focus, with a suggestion to use bidirectional, controllable transmission for optimizing energy storage between New England and Québec.

"The Eversource *proposal* seems like a complete economic and reliability study and [is] consistent with the intended scope of the Future Grid Study," Runge said. "The modeling tools associated with it [Gridview and GE MARS] are used" by ISO-NE.

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

The NESCOE-proposed "pathway" scenario, which would look at the impact of certain electrification assumptions, could work into a larger study as a scenario, he said.

Anbaric's call for identifying an onshore and offshore power system that is carbon-free by 2035 seems outside the scope of the Future Grid study because it identifies a goal and then studies how to achieve it, Runge said. He said it could inform assumptions or sensitivities to the study, rather than being its focus.

Runge did not make any comments about the American Petroleum Institute's request to study how the grid will balance policy goals with other reliability, affordability and energy-access objectives.

He said the remaining proposals had limited focuses "that could be worked into a larger study, or potentially could be used as change cases/scenarios/sensitivities":

- A proposal by *Energy Market Advisors* on behalf of several public power systems suggested an analysis of how capacity interconnection and minimum interconnections would impact markets and operations. FirstLight Power said the base scenarios should not assume significant new electric storage entry to avoid understating potential reliability problems.
- Multi-Sector Group A (Acadia Center, Advanced Energy Economy, Brookfield

ISO-NE News

Renewables, Conservation Law Foundation, Energy New England, Natural Resources Defense Council and PowerOptions) spotlighted a potential need for ramping, regulation and load-following resources.

- Multi-Sector Group B (Advanced Energy Economy, Borrego Solar, Conservation Law Foundation, Energy New England, ENGIE, Natural Resources Defense Council and PowerOptions) asked for a long-term transmission system assessment to identify investments that could eliminate obstacles to reaching net-zero-carbon emissions.
- NextEra Energy and Dominion Energy jointly requested an analysis of the impact of the loss of NextEra's Seabrook and Dominion's Millstone nuclear power plants.

Stakeholder Comments

Anbaric Senior Vice President Theodore Paradise said, "When we were doing our request, we picked 2035 because it fits between the Rhode Island carbon-free goal of 2030 and the Connecticut goal of carbon free by 2040. ... The year probably doesn't matter, though it might for electrification more than for what transmission we think is realistic."

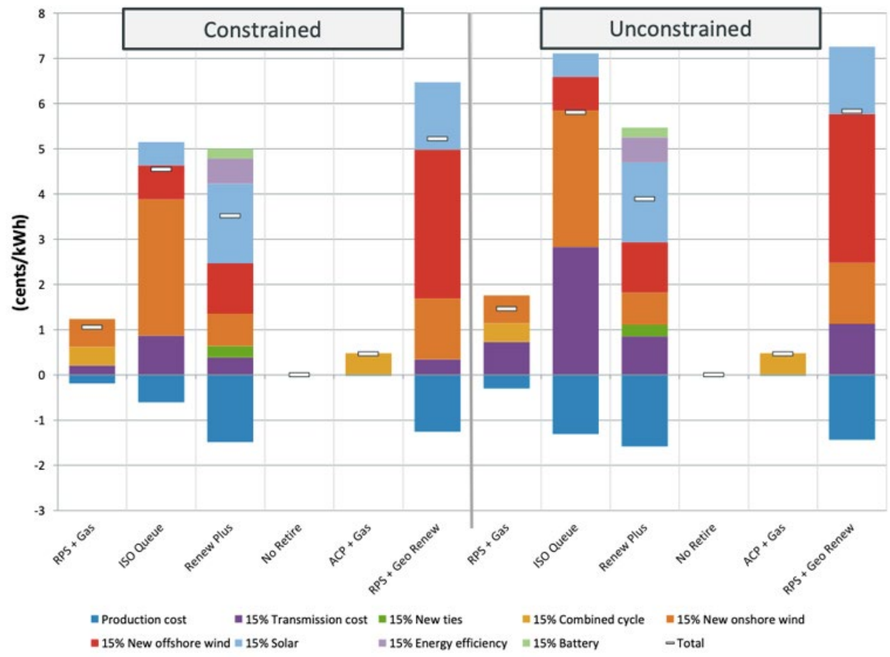
The request isn't to do an integrated resource plan, but to figure out if the market and transmission planning rules work to meet state goals, Paradise said. "We need to know what some version of that system looks like. … If the transmission isn't there, market signals won't lead to more resources."

RTO Feedback

Sedlacek said no single modeling platform could provide all the answers requested. She said the RTO does not have a model for projecting Forward Capacity Market clearing and is wary of developing one "because the marketplace may view it as a projection of anticipated market outcomes by the market administrator."

The Analysis Group has performed FCM price projections for the RTO in the past. Developing study assumptions and modeling parameters typically takes three to six months, and it could take another six to 12 months for the consultant to complete work and provide results. An economic study would likely require use of a probabilistic reliability model such as GE MARS and could be done in about 12 months if done concurrently with the 2020 economic study.

"What I've learned over the last two years working on economic studies ... is that it's very difficult to do multiple economic-type studies all at the same time," Sedlacek said. "There are efficiencies in concentrating on a single study at a time, especially on a topic as complex as the future grid. And the more granular the analysis, the longer it takes."



This 2016 NEPOOL Economic Study graph shows total relative annual resource costs, 2030, with changes compared to 2030 Scenario 4 (constrained) (cents/kWh). Economic modeling was done by ISO-NE using the Gridview tool available to the RTO. | *ISO-NE*

"Recall it took us four months to nail down the assumptions for the National Grid study," she noted.

Projecting ancillary service needs could take at least 15 months because of the need to further develop the Electric Power Enterprise Control System (EPECS) model developed by Dartmouth College, which is a "customized tool that is still in the development stage. It performs the analysis it was designed to do, but additional enhancements are warranted," Sedlacek said.

She also noted that the RTO generally studies incremental changes to the transmission system rather than the detailed transmission expansion some stakeholders seek.

The RTO's staff is too small to handle a large design and modeling project while also performing required interconnection and reliability studies, Sedlacek said, and lacks the necessary skills to appropriately estimate transmission costs. Such an analysis, she said, "would be best performed by engineers with relationships with transmission equipment vendors."

"We would be more than willing to work with ISO-led consultants to conduct this expanded effort once stakeholders have had an opportunity to derive a well defined study scenario," she said.

If stakeholders agree by November on the modeling assumptions for the Future Grid study, the RTO would need to displace the current 2020 National Grid economic study request to make Future Grid the top priority.

Joe Rossignoli, director of business development for National Grid, said he would like to discuss with the RTO how his company's study request would be treated upon being delayed, but he added that "we're good with making way from the resource perspective."

Pete Fuller of Autumn Lane Energy said, "My concern today is that we know how to study what we know, but not how to study what we don't know ... so, I'm not sure our study will tell us what to do to move toward this new future."

Sedlacek said the RTO is unaware of any current model that can provide the "detailed, operational dispatch needs of a system with significant inverter-based resources, interaction between the transmission and distribution systems, and evolving load profiles that may occur in the future." The RTO is beginning work to develop such a model, but it will be "a multiyear effort," she said. ■

ISO-NE News

ISO-NE Sees 722-MW ICR Jump for FCA 15

Tie Line Benefits Down

By Rich Heidorn Jr.

ISO-NE is proposing an installed capacity requirement (ICR) of 34,153 MW for Forward Capacity Auction 15, a 722-MW (2%) increase over FCA 14, in part because of reduced expectations of assistance from its neighbors in an emergency.

The RTO presented its *ICR proposal* and tie line calculations to the New England Power Pool Reliability Committee on Sept. 1. The committee will vote on the ICR and related values on Sept. 23.

ISO-NE calculates the ICR — the minimum system capacity needed to meet Northeast Power Coordinating Council reliability criteria — based on sequential Monte Carlo simulations to probabilistically compute the behavior of loads and resources.

The RTO's annual calculations also account for operators' ability to purchase energy from neighboring balancing authority areas during a capacity deficiency under Emergency Operating Procedure No. 4.

The RTO's Fei Zeng *told* the committee that the Maritimes, Hydro-Québec Phase II, Québec Highgate, New York AC and Cross Sound Cable ties will provide a combined 1,735 MW of tie line benefits for FCA 15 (2024/25), a 205-MW (11%) reduction from FCA 14 (2023/24).

Benefits from the New York AC ties showed the biggest reduction, a drop of 104 MW (29%), followed by a 47-MW reduction for the Maritimes (9%).

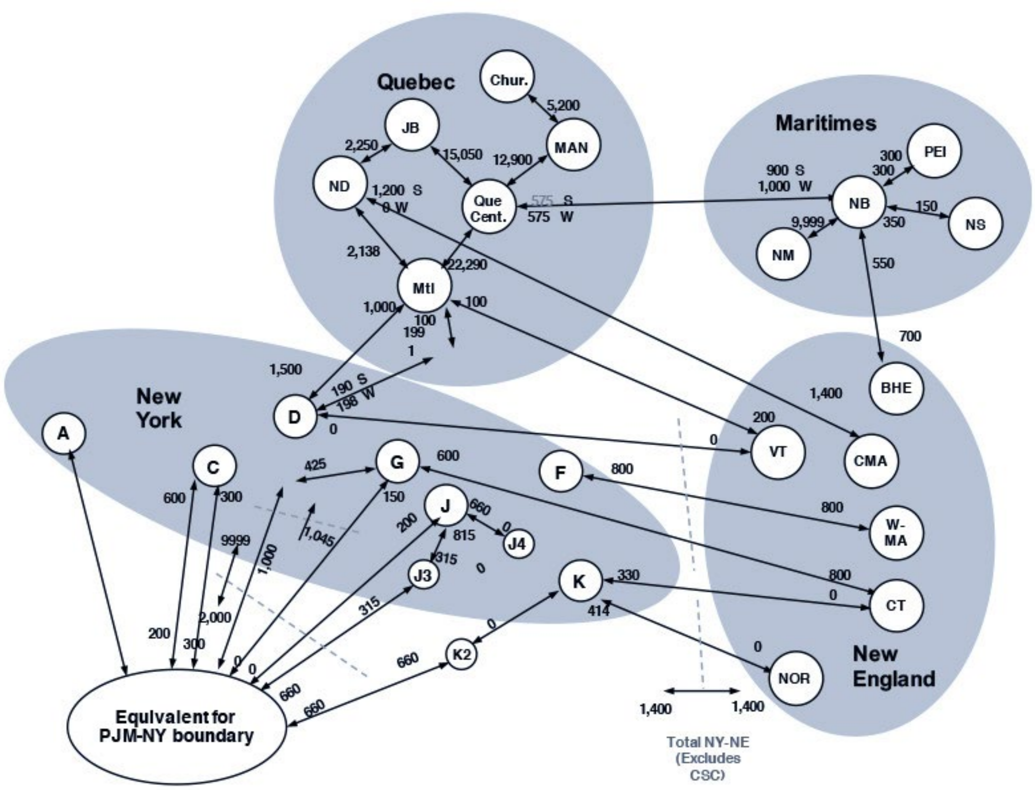
The New York reduction was largely the result of the state's need to meet higher peak and energy demand forecasts because of increased load forecast uncertainty (40 MW). New York's increasing need for emergency assistance available from the Canadian control areas reduced the assistance available to New England, Zeng said.

Another 50-MW reduction was attributed to a change in New York's behind-the-meter PV model: The penetration and hourly shape increased the correlation in the hourly loads between New York and New England.

In addition, a lower Northeast Massachusetts/Boston transmission import capability contributed to a 40-MW reduction, while the retirement of Mystic Units 8 and 9 resulted in a 25-MW decrease. "Tie benefits are a function of how much assistance New England needs and how much assistance our neighboring areas are able to provide," RTO spokesman Matt Kakley explained. "The retirement of Mystic results in a small decrease in what we would need to be able to replace in an emergency."

The region's internal transmission interface transfer limits reflect several anticipated transmission upgrades: the Greater Boston upgrades with the 345-kV Wakefield-Woburn line in service (2021/22); the Greater Hartford/Central Connecticut upgrades; southwest Connecticut upgrades; and the Southeast Massachusetts/Rhode Island reliability project upgrades.

Subtracting the Hydro-Québec interconnection capability credits (HQICCs) of 883 MW (down from 941 MW the prior year), the net ICR is 33,270 MW, a 2% increase over FCA 14. The reserve margin is 16.6% with the HQICCs and 13.5% without.



Interconnected system representation for 2024 (MW) | *ISO-NE*

"HQICCs are capacity credits that are allocated to interconnection rights holders, which are entities that pay for and, consequently, hold certain rights over the Hydro-Québec Phase I/II HVDC transmission facilities," Kakley said.

The gross cost of new entry (CONE) for the cap of the marginal reliability impact system demand curve for FCA 15 is calculated as \$11.951/kW-month, with net CONE at \$8.707/kW-month. The FCA will start at a price of \$13.932/kW-month.

FCA 15 will model the same zones as FCA 14, with Maine nested inside Northern New England as export-constrained and Southeast New England as import-constrained.

The Participants Committee will vote on the ICR and related values on Oct. 1, with a FERC filing expected by Nov. 10. ■

ISO-NE News

NEPOOL Participants Committee Briefs

Energy Efficiency Fix Approved

The New England Power Pool Participants Committee on Thursday approved a change to how ISO-NE accounts for energy efficiency in its gross load forecast reconstitution methodology.

The RTO said the change is needed to ensure gross load forecasts reflect the amount of EE that will clear in the Forward Capacity Auction and avoid counting EE resources with capacity supply obligations (CSOs) as both supply and demand. In the last several capacity auctions, it says, it has cleared less EE than was reconstituted.

The change, which was approved by the Reliability Committee in July, would set the quantity of load reconstitution based on a trend line reflecting historical measures of EE CSOs compared to the level of installed EE. (See "Wholesale Market Consequences of Gross Load Reconstitution Proposal," *NEPOOL Markets Committee Briefs: Aug. 11-13, 2020*.)

The change received a 68% sector-weighted vote of the PC, with unanimous support from the Transmission, Publicly Owned Entity and End User sectors. The change also was supported by about 55% of the Supplier sector, but only one-third of the Alternative Resources sector and only 20% of the Generation sector.

The PC had deferred action on the proposal in August following objections by the New England Power Generators Association (NEPGA), which contended that limiting reconstitution to the trend line based on the forecast could result in EE megawatts clearing in the FCA exceeding the level of forecast EE megawatts reconstituted for that auction.

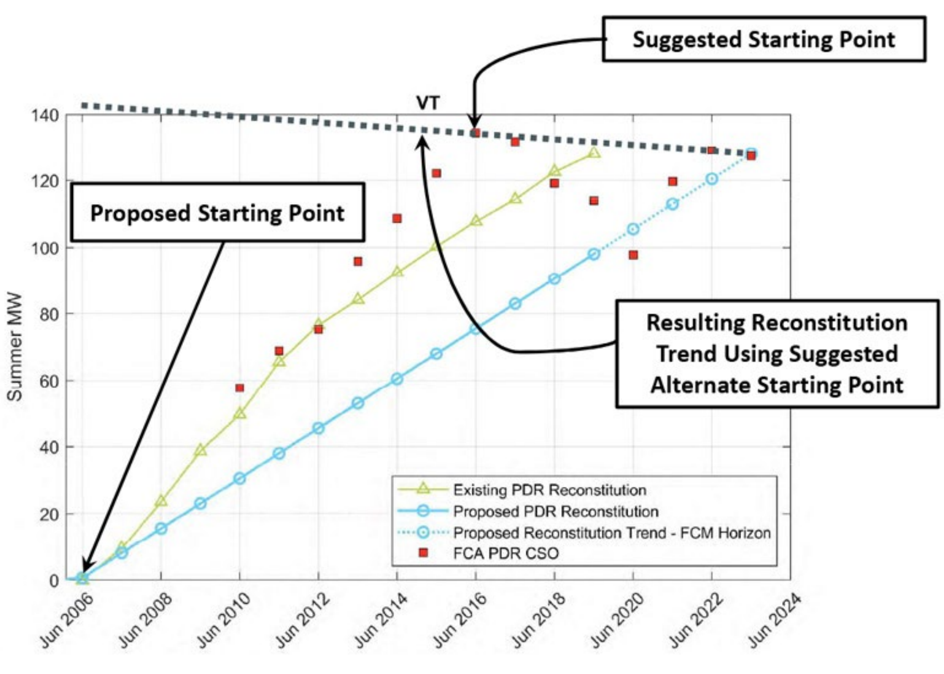
The generators said capacity market prices could be suppressed if EE and other passive demand resources (PDRs) begin to clear more CSOs than reconstituted on the demand side.

NEPGA asked ISO-NE to not qualify EE as capacity supply above the level of EE reflected in the reconstituted peak load forecast, or add a constraint to prevent EE from clearing beyond the level reflected in the peak load forecast.

The RTO declined to endorse NEPGA's proposal.

"The objective of the proposed PDR reconstitution methodology is to produce a reasonably accurate forecast of future PDR CSOs that will be correct on average, over time," Robert Ethier, vice president of system planning, wrote in an Aug. 27 memo. "The ISO believes its proposal achieves that objective. The ISO will continue to observe the clearing of PDRs in the FCM [Forward Capacity Market] and, if it becomes apparent that modifications to the participation of PDRs in the FCM are necessary, then the ISO will return to the stakeholder process."

The RTO hopes to implement the rule change for FCA 16.



ISO-NE's proposed change would set the quantity of energy efficiency load reconstitution based on a trend line reflecting historical measures of EE capacity supply obligations compared to the level of installed EE. | *ISO-NE*

'Challenging' August

ISO-NE Chief Operating Officer Vamsi Chadalavada briefed the committee on what he called a "challenging" August for RTO operations, a month that included Tropical Storm Isaias, which clobbered Connecticut and Western Massachusetts on Aug. 4, leaving 1.2 million customers without power following 32 transmission outages.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, Chadalavada approved his remarks afterward to clarify his presentation.]

ISO-NE declared an M/LCC 2 abnormal conditions alert at 3:40 p.m. on Aug. 4, which continued until 9 p.m. on Aug. 10. Scheduled generation and transmission outages were postponed where possible, and 1,200 MW of capacity was locked in Connecticut because of line outages.

The RTO also saw loads 1,000 to 2,000 MW above forecast during hot weather on Aug. 1, 9 and 10, requiring it to commit fast-start resources to maintain its operating reserves, Chadalavada said.

Aug. 9 presented an additional challenge because of an unplanned transmission outage in the Northeast Massachusetts (NEMA)/Boston area, high loads, the scheduled outage of lines 3163 and 3164 into Boston and resources that normally clear in merit in the day-ahead market not doing so.

The RTO was able to maintain all reliability standards by committing some resources and backing off others in the NEMA/Boston zone, Chadalavada said.

Daily net commitment period compensation (NCPC) for August was $2.9 million, up $1.2 million from July and up $1.3 million from August 2019.

First contingency payments totaled $2 million, up $500,000 from July, including $1.9 million paid to internal resources and $112,000 paid

ISO-NE News

to external resources. Dispatch lost opportunity cost was $158,000, and rapid response pricing opportunity cost was $297,000.

Chadalavada said operators were performing "a balancing act" in deciding not to recall the outage of lines 3163 and 3164, saying that delaying too many scheduled outages would push more maintenance work into the peak maintenance season in the fall.

ISO-NE Proposes 2.5% Budget Increase

ISO-NE is proposing a $178.6 million operating budget for 2021, a $4.4 million (2.5%) increase excluding FERC Order 1000 funding and before depreciation.

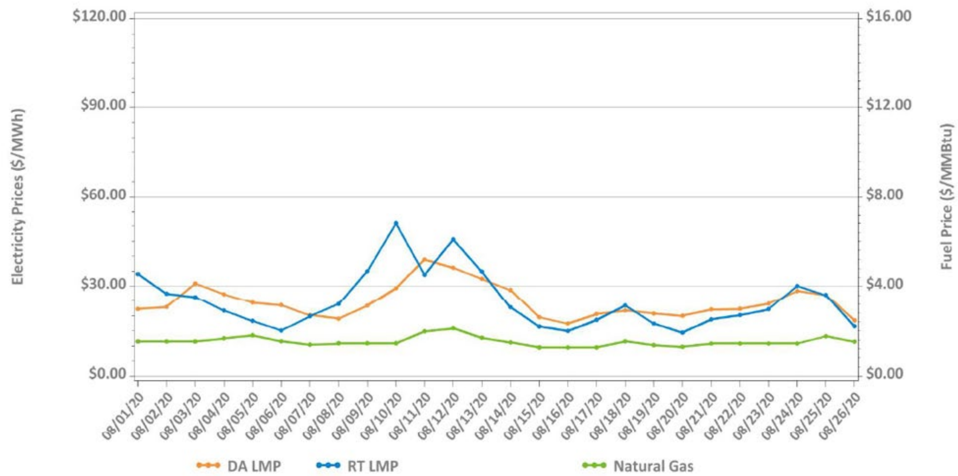
Including depreciation and FERC Order 1000 funding, the increase is $3.2 million (1.6%).

The budgets include no increase to the full-time-equivalent employee headcount of 587.

Robert Ludlow, the RTO's chief financial and compliance officer, said in a memo that the increase included inflation adjustments to compensation costs; implementation of the Energy Security Improvements (ESI) initiative; work related to renewable resources and emerging technologies; and cybersecurity and NERC Critical Infrastructure Protection (CIP) compliance.

The 2021 operating budget does not include funding for FERC Order 1000 costs because the RTO expects to underspend its Order 1000 budget by about $600,000 in 2020. Most spending on the issue in 2021 will be for legal expenses for protests and other filings.

The committee approved a modification to the ISO-NE Tariff's true-up provision to allow the RTO to carry such unspent "special purpose" funding over to 2021 rather than having to return it.



Average day-ahead and real-time ISO-NE Hub prices and natural gas prices: Aug. 1-26, 2020 | *ISO-NE*

The capital budget — which will fund ESI, the nGEM market clearing engine, nGEM software development (part II), cybersecurity improvements and a redesign of the CIP electronic security perimeter — will be unchanged from 2020 at $28 million.

Ludlow noted concerns of state officials that the RTO would not have enough internal resources to support the Future of the Grid initiative and that freezing the FTE headcount could have a negative impact on the Markets Development and System Planning departments.

"We shared that there was too much uncertainty regarding work related to the 'Future of the Grid/Markets' discussions to build in budgeted dollars and, to the extent additional resources or analyses are necessary, they will be funded through the contingency," Ludlow wrote.

The New England States Committee on Electricity (NESCOE) also presented its proposed $2.4 million budget for next year, a $7,200 increase over 2020 and $113,000 below the $2.5 million projected in its five-year *pro forma* budget.

NESCOE said the reduction reflected "continued rebalance" of technical and legal spending and reductions in travel and professional services costs.

The PC will vote on the budgets at its October meeting. ■

— Rich Heidorn Jr.

MISO News

MISO, SPP Regulators Ponder Monitors' Recommendations

Members Plead for More Transmission Projects

By Amanda Durish Cook

MISO's and SPP's market monitors last week presented their last report to state regulators working to improve the RTOs' interregional coordination, but members seemed more interested in the lack of joint projects between the two.

MISO Independent Market Monitor David Patton presented his report Aug. 31 on interface pricing to the Seams Liaison Committee (SLC), composed of regulators from the Organization of MISO States (OMS) and SPP's Regional State Committee (RSC). It was the last of the monitors' studies and reports commissioned by the SLC.

When invited to give their chief concerns about the grid operators' coordination, stakeholders seemed less focused on interface pricing and more interested in why the RTOs have been unable to agree on beneficial interregional transmission projects.

The American Wind Energy Association's Daniel Hall criticized the RTOs' use of different planning futures, models and assumptions in their coordinated system plan (CSP), the studies they use to search for interregional projects.

"There is a need for large interregional projects, but it's not showing up in the regional studies, and that's a problem and we need to address that," he said.

MISO last month said it doesn't plan to endorse any interregional project possibilities this year after a fourth CSP with SPP. (See *MISO, SPP Close to Ruling out Joint Projects Again*.)

ITC Holdings' Brenda Prokop said many transmission owners are similarly questioning the design of the RTOs' interregional planning, especially because the TOs are forecasting a "strong need" for transmission buildout along the seam.

"We're wondering if it's the most cost-effective and efficient way for the RTOs to be planning in their separate regional process," Prokop said. She also asked that MISO and SPP "line up" their models and assumptions.

Hall suggested the regulators consider urging the RTOs to create a new category for small, economic interregional transmission projects, called targeted market efficiency projects. MISO and PJM debuted the project type three years ago and have since approved two portfolios of smaller projects.


Texas PUC Chair DeAnn Walker questions SPP staff during an RSC meeting. | © *RTO Insider*

American Electric Power's Jim Jacoby said regulators should support the creation of the project type. MISO and SPP considered developing smaller projects two years ago but called off the effort. (See *MISO, SPP Mulling Small Interregional Project Type*.)

Hall also urged regulators to investigate the eradication of rate pancaking and the possibility of a joint dispatch model between the two RTOs. He said the monitors' earlier conclusion that joint dispatch wouldn't benefit the grid operators doesn't consider reliability advantages and the possibility of capacity-sharing.

Members: Tx, Please

The IMM's study on interface pricing concluded that the RTOs need only include congestion from their monitored constraints when calculating interface prices. Currently, both MISO and SPP estimate the flow's impact and congestion costs on all market-to-market (M2M) constraints, even those they aren't monitoring.

"Both of us are pretty much estimating the full impact of scheduling the transaction," Patton said. "In the report, we call this a redundant payment, and it is the primary problem identified in the report that needs to be solved."

Patton said interface payments can be large because the RTOs' congestion-calculating redundancies exaggerate the cost of moving power over constraints.

He also said nothing in the RTOs' joint operating agreement provides for refunds when interface prices are overinflated by twice-counted congestion on M2M constraints.

"So ultimately, those payments are just going to show up as uplift that SPP customers pay on MISO constraints, and vice versa," Patton said.

Texas Public Utility Commission Chair DeAnn Walker asked why the RTOs aren't already calculating congestion on just their monitored M2M constraints.

"The RTOs aren't doing this yet because it hasn't risen to the top of the heap," Patton said. He said the switch would entail software changes for both grid operators. That might be especially difficult for MISO, as its IT crews are already taxed with rolling out a new market platform.

The OMS and RSC have discussed presenting by year-end a list of recommendations on how the RTOs can better coordinate across the seam. (See *MISO, SPP Regulators Mull Seams Recommendations*.)

Walker said that as the regulators compile their list of recommended improvements, they might reach out to the monitors for advice.

"I don't think they're totally off the hook," she said. "In forming our recommendations, we may ask for some input."

"As market monitors, we see evidence of things not working well. I think state involvement is very important," Patton said.

Hall said regulators should keep the SLC alive after it issues recommendations to oversee the RTOs' handling of them and to continue monitoring areas of improvement in seams coordination.

The SLC will meet again Sept. 14. RTO staffs are expected to appear and respond to the monitors' and members' ideas for improvement. ■

MISO Keeps Advisories in Effect a Week After Laura

By Amanda Durish Cook

Hurricane Laura aftermath | *Entergy*

MISO staff continue to keep advisories in effect and compile data on the MISO South emergency and subsequent rolling blackouts caused last week by Hurricane Laura.

The RTO said Laura was the strongest storm to hit Louisiana in 150 years.

"The southeastern Texas and southwestern Louisiana areas of the MISO footprint sustained substantial damage to the transmission facilities under MISO's functional control, as well as to interconnected generation and distribution facilities, requiring careful and deliberate focus on maintaining system stability," the RTO *said*.

Laura's path of destruction Aug. 27 caused MISO to direct Entergy to employ periodic power outages in the western half of the West of the Atchafalaya Basin (WOTAB) load pocket that spans the Texas-Louisiana border. (See *MISO Enacts Rolling Blackouts in Laura Aftermath*.)

MISO said that as a result of the widespread grid damage, the area's constraint locations have temporarily changed. It said it is investigating the locations to include them in modeling.

"It is important that any unique restoration system conditions are captured correctly in MISO's market models and the bids and offers they clear, to properly incentivize additional, economic generation as part of the restoration efforts," MISO said.

The grid operator *reported* that $3,500/MWh value of lost load pricing was in effect for some of the WOTAB's commercial nodes from 11:40 a.m. to 10:55 p.m. ET on Aug. 27.

MISO has put standing capacity and transmission advisories in place for the areas affected by the hurricane, warning members that generation and transmission capacity could become scarce as restoration work continues. It also *canceled* a monthly training drill on firm load shedding planned for Sept. 2 in MISO South because of an extended conservative operations *declaration* through yesterday in some areas.

Chris Miller, FERC liaison to MISO, thanked MISO South members for their restoration efforts along the Gulf of Mexico and surrounding areas.

"I know it's a big event. It's an ongoing situation, and I want to give a hearty 'thank you' to everyone working to get power back to people," Miller said during a Reliability Subcommittee meeting Thursday.

Restoration worker handling new wires | *Entergy*

Entergy *said* the bulk of lingering outages lies in its Louisiana territory. The utility said that as of Thursday, it has restored 81% of the 616,000 power outages caused by Laura; however, it also said that more than 108,000 of the 271,000 Louisiana customers affected by Laura remain without electricity. The company said nearly all the 291,300 Texas customers affected by the hurricane would be restored by Sept. 4.

Entergy said it is committed to a swift restoration but warned that customers in the city of Lake Charles and Cameron and Calcasieu parishes will "face weeks" without power.

"Our damage assessments indicate catastrophic damage to our electrical infrastructure. We expect the recovery to be as difficult and challenging as we have ever faced in the past," Entergy said. "The damage from Hurricane Laura's historic intensity caused catastrophic damage to the Entergy system across Louisiana and Texas. The eye wall, which brings the most damaging winds and intense rainfall, passed directly over Lake Charles, La., causing wide-spread damage to that area and our system."

Entergy reported 219 out-of-service transmission lines, 292 damaged substations and sizable distribution system damage.

SPP CEO Barbara Sugg said before, during and after the storm's landfall, there was coordination among SPP, MISO, ERCOT, regulators, American Electric Power and the Edison

MISO News

Electric Institute.

"Together, we addressed voltage and severe loading issues, monitored required load sheds and mitigated the risk of major, potentially catastrophic outages both during the event and through restoration efforts," Sugg said in an emailed update. "Certainly, load shed events are unfortunate and undesirable. However, I'm proud of the interregional coordination to protect the bulk electric system."

She said she has received "messages of gratitude" from MISO leadership.

More Detail on July Emergency

Meanwhile, MISO staff last week released more information on the July 7 maximum generation event that affected its North and Central regions.

Speaking during the RSC meeting, MISO System Operations Senior Adviser Gerald Rusin said the RTO may not have needed to enact emergency measures. He said MISO's North and Central regions were spared from more intense heat by widespread pop-up thunderstorms that began around 1 p.m. July 7. While generation and load-modifying resources' emergency ratings were available to meet forecasted load, Rusin said LMR use wasn't necessary. (See *Max Gen Event Managed Efficiently, MISO Says*.)

"At the time that we made the declaration, the numbers were pointing that way," he said, citing forecasted temperatures in the low 90s in the North and Central regions and a "near peak" combined load of 88.5 GW for the two regions.

COVID-19 pandemic load profiles that continue to be unpredictable also contributed to some uncertainty during the event, Rusin said. He said unplanned generation outages have been steadily increasing since April, possibly because of the pandemic. By July, unplanned outages had risen to more than 10 GW, uncharacteristically high for the month known for peak demand, he said.

"We need to see how this plays out in the months to come to see if the true effects of COVID caused the pattern to persist in this way," Rusin said.

Ultimately, systemwide MISO load peaked at 114 GW for the month on July 8. The RTO experienced an average 88.4-GW load during the month, slightly higher than 2019's 88.1-GW systemwide average.

Damaged transmission tower after Hurricane Laura | *Entergy*

Executive Director of Real-Time Operations Rob Benbow said MISO will update its termination declarations after some stakeholders said it wasn't completely clear through RTO communications which emergency steps ended and when during the July event.

"We want to make sure it's clear and that everyone is on the same page as we step down protocols," Benbow said. ■

MISO News

Sustainable FERC Project Spotlights Nixed MISO Renewables

By Amanda Durish Cook

The Natural Resources Defense Council's Sustainable FERC Project has released a new interactive map of MISO's interconnection queue, highlighting how many renewable gigawatts the footprint has lost out on because of limited transmission capacity.

The organization's director, John Moore, said it's important for regulators and policymakers to see where once economic renewable generation projects have evaporated.

"The primary reason we did this is the MISO doesn't offer a lot of insights into the locations of these projects. And I don't think people are aware of the projects that are growing and dying right in their backyards," Moore said in an interview with *RTO Insider*.

The map displays in-progress and canceled projects on the county level. The Sustainable FERC Project found that 245 clean energy projects — or 40% of withdrawn projects over the past four and a half years — "had reached advanced stages of the generator interconnection process" when they were shelved. The organization said the projects could have generated 30.9 GW.

Michigan and Minnesota had the most withdrawn generation projects, the organization said. Michigan, which experienced a capacity shortage to meet local load obligations in this year's MISO capacity auction, saw 42 projects worth about 5.1 GW abandoned from 2016 to 2020. Minnesota saw 36 projects that could have generated nearly 5 GW withdraw.

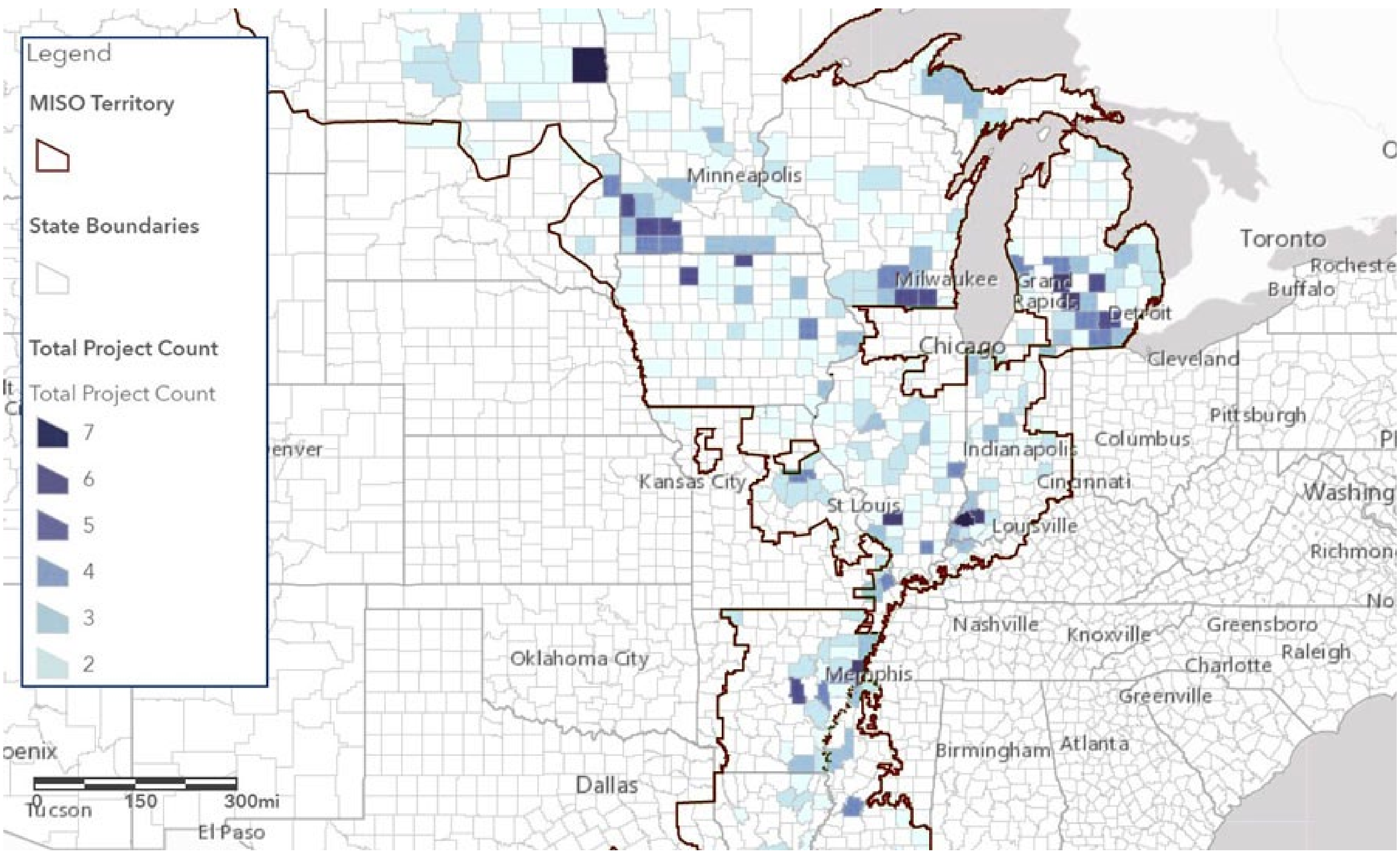
"It illustrates in another way that problem," Moore said of the map. "Twice as many projects are falling out of the queue than normal because of the cost of integrating them."

The Sustainable FERC Project said many developers are forced to scratch projects because of MISO's inability to approve "large-capacity transmission lines and grid upgrades." Moore said that while the cost of network upgrades isn't the only reason for projects falling out of the queue, it's become the most significant one.

MISO last month announced it will embark in a series of long-range transmission studies that could produce project approvals as early as the end of 2021. (See *MISO Processing Heftiest Interconnection Queue Ever*.) The grid operator is also working with stakeholders to try to better line up its annual transmission planning with needed network upgrades that are identified in interconnection queue studies.

The MISO queue currently contains 756 projects totaling 113 GW, 64% of which is solar. It's the grid operator's largest-ever interconnection queue, with 353 project proposals representing about 52 GW of new generation entering in July alone.

Moore isn't hopeful all that solar generation will see the light of day. He said MISO is late to arrive at the long-term transmission studies, and he predicted that many projects in the record-breaking queue will fall off.



Sustainable FERC Project's MISO queue map | *NRDC*

MISO News

"I'm still not hopeful because I don't think the planning is keeping up with the queue," Moore said. "The costs for the network upgrades are obviously far too expensive for any developer to absorb. So, no, I'm not hopeful."

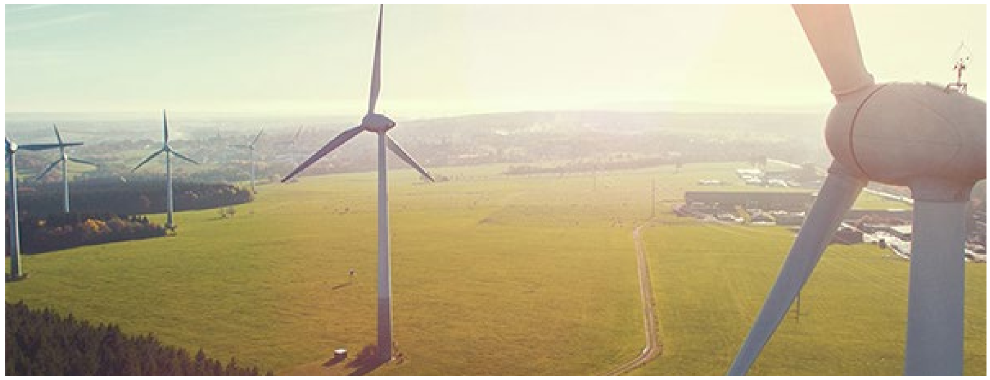
Clean Grid Alliance, Solar Energy Industries Association and the American Wind Energy Association said upgrade costs have been raising the cost of renewable generation projects in MISO West by more than 60% on average.

The Sustainable FERC Project's map doesn't yet include the lineup of new projects that entered in July, but Moore said his organization plans to update it and continue to keep tabs on unrealized projects for regulators and policymakers.

"Leaders aren't familiar with the types of projects that are coming and going and trying to get on the system," he said.

Moore said that though MISO is moving in "better directions" with a long-term transmission process approach and trying to coordinate grid planning, states' clean energy targets could be compromised by project withdrawals. He pointed to integrated resource plans in Michigan and Minnesota, which order more renewables online while the two states see promising proposals vanish.

"Whatever the intention of utilities, the lack of transmission makes it significantly harder," Moore said, adding that MISO could benefit from using longer-term study assumptions for both generator interconnection and transmission planning.



| NIPSCO

The Sustainable FERC Project pointed to EDP Renewables' planned 100-MW wind farm in southwestern Minnesota that was dropped this year after MISO assigned the project an $80 million network upgrade cost — eight times what the developer expected.

EDP Origination Manager Vipul Devluk said the project could not absorb the cost burden. "Ultimately, we had to cancel our power purchase agreement discussions with the customer, and we had to relay to the local community that the benefits they were expecting from this project would not be forthcoming," he said.

Moore said that even MISO South is susceptible to thwarted renewable megawatts because of MISO's lack of transmission buildout. The map shows Mississippi lost nearly 2 GW in planned solar generation from 2016 to 2020.

"There is economic development and carbon-free energy being left on the table," Moore said. "Once there were projects, and now there are none; once there were plans, and now they're gone."

MISO spokesperson Allison Bermudez said the RTO "continues to work with our stakeholders to determine the most cost-effective transmission investments needed to support future energy needs." She declined to comment further on the map.

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

NYISO News

NYISO Looks at Pricing Supplemental Reserves

By Michael Kuser

As new solar and wind energy resources come onto the grid, NYISO is preparing to be able to adapt its reserve requirements quickly to a changing resource mix by procuring supplemental reserves during times of system uncertainty.

Supplemental reserve procurements can help provide for system uncertainty introduced by weather-dependent resources, both distributed and grid-connected, as well as potentially more volatile load, according to NYISO. It hopes to have a market design complete this year, Pallavi Jain, energy market design specialist, *told* the Installed Capacity/Market Issues Working Group last week.

NYISO is not proposing to add any supplemental reserve requirements now. Rather, it will propose Tariff revisions to establish the process and procedures for implementing requirements when warranted in the future, Jain said. The reserves would be priced lower than the proposed lowest shortage pricing value, $25/MWh, in tiers:

- Any 30-minute reserves: $10/MWh
- 10-minute total reserves: $12/MWh
- 10-minute spinning reserves: $15/MWh

To help determine the appropriate values, the ISO analyzed historic reserve shadow prices and reserve supply offers.

	10-minute spin		10-minute total		30-minute	
	95th percentile of offers	99th percentile of offers	95th percentile of offers	99th percentile of offers	95th percentile of offers	99th percentile of offers
NYCA	$7/MWh	$50/MWh	$5.95/MWh	$11.74/MWh	$8.75/MWh	$50/MWh
NYC and LI	$5.5/MWh	$6/MWh	$6.45/MWh	$14.49/MWh	$8.75/MWh	$10/MWh

Pricing analysis of historic reserve supply offers, with those from New York City and Long Island broken out separately to help identify any potential for material differences in offer costs from resources in these regions. | *NYISO*

Stakeholder Concerns

Couch White attorney Kevin Lang, representing New York City, said he was concerned about extending undue discretion to the ISO to change reserve requirements without stakeholder authorization.

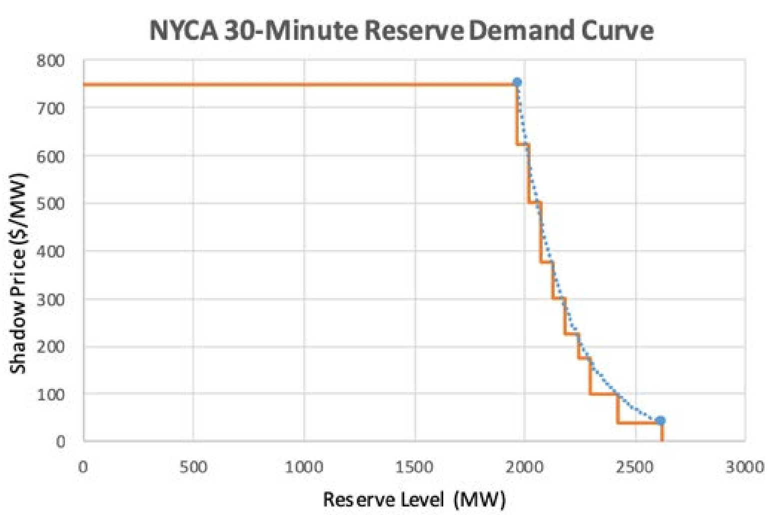
Increasing reserve requirements is in conformity with current practice, with any action taken brought to the soonest meeting of the Operating Committee, said Aaron Markham, director of grid operations at NYISO. "We want to be prepared to change quickly to meet reliability needs," he said.

Brian Wilkie, manager for New York wholesale strategy at National Grid, suggested that the ISO could communicate its needs beyond the OC, as many stakeholders do not attend its meetings.

Michael DeSocio, NYISO's director for market design, said there is a way to balance stakeholder concerns and still provide flexibility for the grid operator.

"We're not delaying addressing any reliability needs, and still have the issue of developing the software we need," DeSocio said. "I do worry that there is a notion that we can continue to rely on out-of-market actions ... which is probably not in the best interests of consumers in the long run, nor in the best interests of achieving the state's clean energy goals."

Stakeholders were also presented a consumer impact analysis to aid further discussion of the proposal. NYISO currently plans to seek stakeholder approval of the proposal at the October meetings of the Business Issues and Management committees. If approved, the enhancements would be implemented in 2021, which the ISO expects to occur after implementation of the Reserves for Resource Flexibility project. ■



Shortage Price ($/MW)	Reserve Level (MW)	Demand Curve (MW)
750	≤ 1,965 to 0	1,965
625	1,965 to 2,020	55
500	2,020 to 2,075	55
375	2,075 to 2,130	55
300	2,130 to 2,185	55
225	2,185 to 2,240	55
175	2,240 to 2,295	55
100	2,295 to 2,420	125
40	2,420 to 2,620	200

Note:
- Highlighted shortage price cells indicate the values from the costs of operator actions analysis

NYISO's proposed 30-minute reserve demand curve during emergency DR/special-case resource events | *NYISO*

NYISO News

FERC Rejects NYISO Bid to Aid Public Policy Resources

Glick: Ruling will 'Doom' ISO's Capacity Market

Continued from page 1

But the commission said they should be treated the same because "they must adhere to similar requirements for interconnection and for participation in the" ISO's Installed Capacity (ICAP) Market.

"Further, our finding that NYISO's proposal is unduly discriminatory is dispositive," the commission added. "We need not reach NYISO's arguments that its proposal would not cause price suppression."

James Denn, spokesman for the New York Public Service Commission, said the state will seek to overturn the ruling.

"Longstanding FERC policy and precedent respected state's rights. But this constitutionally protected idea apparently means nothing to this administration. If allowed to stand, this decision would cause tremendous economic and environmental harm across the country by intentionally increasing energy prices for consumers to line the pockets of fossil fuel interests and undermining successful renewable energy policies that have created hundreds of thousands of jobs."

"We worked closely with market participants on a design we felt addressed FERC's jurisdictional obligations and New York's right to implement renewable energy policies," said NYISO CEO Rich Dewey. "We're reviewing the order to assess next steps and remain confident we can find a regulatory solution acceptable to all parties that supports the changing grid."

The ISO's buyer-side market power mitigation rules require new ICAP resources in New York City and zones G-J to offer at or above the default offer floor — 75% of the net cost of new entry (CONE) of the hypothetical unit modeled in the most recent ICAP demand curve reset — until they clear 12 monthly auctions.

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 the net CONE of the new entrant.

4 Changes

NYISO proposed four changes to its rules, saying they would "better reflect changes in resource investment and retirement decisions and, ultimately, the composition of the overall resource mix that are expected to take place in New York state."

The changes would:

- modify the ISO's current practice of performing the Part B test before the Part A test by swapping their order;
- establish two separate mitigation study periods (Group 1 and Group 2), each covering three consecutive years;
- Evaluate resources under the Part A test for each capability year of a resource's three-year mitigation study period; and
- put public policy resources ahead of nonpublic policy resources in Part A evaluations.

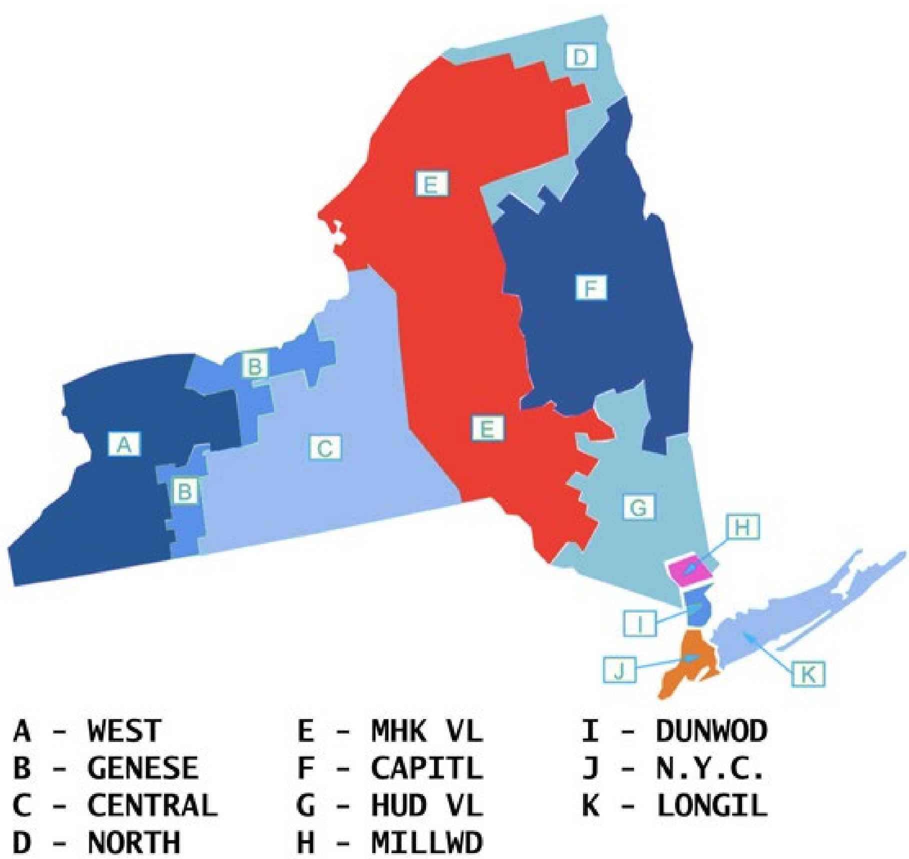
The commission said the proposal "would unjustifiably limit nonpublic policy [resources'] ability to pass the Part A test and participate on an equal footing with public policy resources."

The ISO contended public policy resources are more likely to secure the necessary permits and siting permissions, secure firm off-takers and receive favorable financing, and that nonpublic policy resources are unlikely to enter the market in the future.

It cited the Climate Leadership and Community Protection Act, which calls for 70% of New York's electricity to come from renewable resources by 2030 and for electricity generation to be 100% carbon-free by 2040. It also nearly quadrupled New York's offshore wind energy target to 9 GW by 2035.

It also cited the Accelerated Renewable Energy Growth and Community Benefit Act, which established an office to accelerate the permitting of large renewable energy facilities. (See *Cuomo Proposes Streamlining NY's Renewable Siting*.)

Because of these policies, NYISO said a resource's cost structure is no longer the best predictor of whether it will ultimately get built.



New York Control Area load zones | *NYISO*

NYISO News

Because its proposal will not change how much capacity qualifies under the Part A test, it will not result in price suppression, the ISO said.

"While NYISO's filing makes references to certain New York state laws, regulations and policies that it argues will drive the composition of New York state's resource mix, we disagree that the prevalence of public policy resources in the future composition of New York state's resource mix means they are not similarly situated to nonpublic policy resources for the purposes of the Part A test," the commission said.

It also said it was not persuaded by the Monitor's contention that the proposed realignment will minimize surpluses and avoid inefficient incentives for investment in new resources. States "are free to make their own decisions regarding how to satisfy their capacity needs, but they 'will appropriately bear the costs of [those] decision[s],' ... including possibly having to pay twice for capacity," the commission wrote, quoting from a 2009 D.C. Circuit Court of Appeals ruling.

"While we respect that New York state may have initiatives to favor the development of certain types of resources, we reiterate that we must base our decision on our duty to ensure just and reasonable rates pursuant to the [Federal Power Act], and not on whether the proposal is consistent with federal, state or municipal renewable energy policies."

Glick Dissents

Glick said the majority's "deeply misguided" ruling "is just the latest in the commission's ever-growing compendium of attempts to block the effects of state resource decision-making," an apparent reference to its December ruling requiring PJM to expand its minimum offer price rule to include all new state-subsidized resources.

"This time the commission does not even bother trying to hide behind 'price suppression,' 'investor confidence,' 'market integrity,' 'the premise of capacity markets' or any of the other inscrutable buzz words that it has used to justify its efforts to 'nullify' state policymaking," Glick said. "Without disputing NYISO's explanation that these reforms would not cause any 'price suppression,' the commission nevertheless rejects the filing because it would expressly facilitate the entry of resources needed to meet New York's public policy goals."

Glick termed the ISO's proposal "a set of minor but eminently reasonable changes" to ensure that the Part A exemption test reflects the commercial and regulatory realities under state policies. The majority's order used "perfunctory reasoning that displays not even the slightest effort to wrestle with, or even correctly characterize, the arguments advanced by NYISO or the other supporting parties."

He said the fact that the public policy resources are subject to the same market and interconnection rules as nonpublic policy resources is "irrelevant."

"The commission has repeatedly recognized that state support may constitute a distinguishing factor that renders resources not similarly situated. For example, in its order accepting ISO New England's Competitive Auctions with Sponsored Policy Resources construct, the commission approved of an entire new market — the substitution auction — that was open only to state-sponsored resources," he said.

The order "appears to stake out the new, and even more radical, position that it is improper for an RTO to design its Tariff in a way that even acknowledges, much less accommodates, state public policies — an approach that is both fundamentally misguided and a striking departure from commission precedent and practice," Glick said.

The majority "puts RTOs and ISOs in an impossible position, forcing them to juggle the commission's ideological antipathy toward state efforts to shape the resource mix with the realities that Congress gave states responsibility over resource decision-making and that the physical system will ultimately, and rightfully, reflect those state choices. ...

"The proposal received a supermajority of votes in the stakeholder process, and not a single party protested this issue before the commission, including any of the generator groups that have cheered on the commission's slew of recent buyer-side mitigation orders. But, of course, the commission thinks it knows better than NYISO's stakeholders, better than NYISO's Market Monitoring Unit, better than the New York state Public Service Commission and better than the people of New York. ...

"The most likely outcome of the commission's misguided campaign to 'protect' capacity markets is their ultimate dissolution. Today's order makes that result all the more likely. New York is currently considering whether to 'take back' resource adequacy from NYISO, a move motivated in large part by the commission's efforts to prevent the NYISO market from reflecting the state's policy choices. The evident hostility toward state policies displayed in this order will only add fuel to that fire." ■

PJM MIC Briefs

Market Suspension Guidance Endorsed

The PJM Market Implementation Committee last week unanimously endorsed the development of business rules outlining how the RTO would address a market suspension from an emergency or some other incident.

At the MIC meeting Wednesday, Stefan Starkov of PJM reviewed updates to the *problem statement* and *issue charge* for the initiative, reflecting changes since the issue was brought to a first read last month. (See "Market Suspension Settlements," *PJM MIC Briefs: Aug. 5, 2020*.)

Starkov said PJM acted after realizing it had limited guidance on how to handle settlements during a market suspension with no day-ahead or real-time LMP results. Starkov said PJM doesn't anticipate that a market suspension would occur, but the RTO wants to be prepared.

Phase 1 work includes defining the term "market suspension," reviewing consequences to PJM markets from such an event and identifying and implementing any necessary changes to PJM's business rules to accommodate the impact of a market suspension on settlements.

An additional point was added to indicate Phase 1 of the initiative is focused solely on addressing the lack of energy market clearing prices and does not include forward-looking financial transmission rights and capacity auctions.

Phase 2 work includes identifying and implementing any other business rule changes needed to respond to a suspension.

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

Work on Phase 1 is expected to take three months, and Phase 2 is estimated to take six months to complete. Work is set to begin in October.

Paul Sotkiewicz of E-Cubed Policy Associates said it was a problem statement and issue charge that was "long overdue" considering the risk of cyber threats. He asked how far the work will go to address systems operations in PJM, including how dispatch would be done in a scenario with no markets.

PJM's Tim Horger said the idea was to focus narrowly on the settlement process and how to price the market without real-time LMPs. Horger said PJM didn't want to expand the work scope to look at operations.

Sotkiewicz said he understands and agrees with the focus on market settlements, but he also sees the possibility of a market suspension coupled with computer system problems impacting dispatch and operations. He said the issue could possibly be examined in the Operating Committee.

Gary Greiner, director of market policy for Public Service Enterprise Group, asked why the issue wasn't being brought to the Market Settlements Subcommittee to be deliberated. He said the scope of the work seemed to be tailored to the subcommittee and would allow stakeholders to utilize experts to discuss the issue more in depth than would be possible at the MIC.

"It allows our subject matter experts to get into the process," Greiner said.

PJM said the work on the issue was better suited for the MIC because of its scope.

Stability Limits Endorsed

Stakeholders endorsed a joint package between PJM and the Independent Market Monitor of a capacity constraint proposal regarding *stability limits in markets and operations*.

The proposal, which was *reviewed* by Joe Ciabattoni of PJM, was endorsed with 64% approval, passing the required 50% threshold. The proposal then won 71% endorsement over maintaining the status quo.

A second package, the opportunity cost proposal put forward by J-POWER, won 58% support and will serve as a secondary package in voting by the Markets and Reliability Committee.

The proposals were the result of several

Gary Greiner, PSEG | © *RTO Insider*

months of discussion at the MIC on potential changes to how PJM curtails generating output when needed to maintain stability during maintenance outages. Generating units must sometimes be reduced below their normal economic max limit if a planned or unplanned transmission outage presents stability problems that could result in damage to the units. (See "Stability Limits in Markets and Operations," *PJM MIC Briefs: May 13, 2020*.)

Current rules require the RTO to implement a thermal surrogate to reflect the stability constraint in the day-ahead and real-time markets and to bind the constraint, affecting the unit's dispatch.

The MIC agreed in August 2019 to consider alternative approaches in response to a problem statement and issue charge by Panda Power Funds' Bob O'Connell, who said PJM's decision to remove supply from the market to address stability constraints would result in some units committing at price-based offers, rather than cost-based. Under the RTO's rules, only the affected generator would know of the constraint, which stakeholders said would lead to a competitive advantage over other units, possibly resulting in greater mark-ups in their offers. (See "Modeling Units with Stability Limitations," *PJM MIC Briefs: Aug. 7, 2019*.)

The capacity constraint proposal addresses the allocation of limits to multiple units by stating that the limit will apply to the sum of the output of the affected units plus ancillary service megawatts. Ciabattoni said the units would be dispatched in economic merit order up to the stated stability limitation.

If a stability limitation has been identified

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during the planning process and the unit chooses not to remedy the stability limitation, Ciabattoni said, the operating restrictions for the unit — as documented in its interconnection service agreement — would be utilized prior to other units being reduced.

Lost opportunity cost (LOC) credits would not be paid for any reduction required to honor the stability limit. Similarly, LOC is not paid for economic megawatts of a resource that cannot produce because of a ramp limitation.

Sotkiewicz, who presented the J-POWER opportunity cost proposal, said the package was fundamentally the same as the PJM-Monitor package except for providing compensation for LOCs. He said payment for LOC is permitted by section 3.2.3f of the Attachment K Appendix to the Tariff.

The compensation measure sends the right price signal to generation to accept being backed down, avoids the modeling problems of the thermal surrogate and avoids the appearance of physical withholding of capacity by forcing a unit to take an outage, Sotkiewicz said.

Tom Hyzinski of GT Power Group offered a friendly amendment to the proposal regarding after-the-fact reporting. The capacity constraint package originally called for reporting the frequency of the use of the capacity constraint on a monthly basis maintaining the confidentiality of market-sensitive data.

Hyzinski requested that PJM report on a monthly basis the number of instances (defined as a generator hour where the capacity constraint was called), the amount of megawatt-hours constrained and the number of generators that were impacted in the day-ahead and real-time markets.

Terri Esterly, PJM | © *RTO Insider*

Rules governing how to handle settlements during a market suspension with no day-ahead or real-time LMP results were "long overdue" considering the risk of cyber threats.

—Paul Sotkiewicz, E-Cubed Policy Associates

A compromised amendment that was adopted said, "Data will be made available to the market to increase transparency on frequency, location and number of affected units to the extent it is consistent with confidentiality rules. This language will be refined prior to the presentation at the MRC."

Manual language will now be developed and presented for a first read at the October MRC meeting.

Behind-the-meter Generation

Terri Esterly of PJM provided a *presentation* and a first read of the *problem statement* and *issue charge* addressing clarifications to the behind-the-meter generation (BTMG) business rules as they relate to a unit changing status from netting against its load to participating in PJM markets.

Esterly said a BTMG unit can be designated to be a capacity resource or energy resource in the wholesale markets or be designated as BTMG netting against load on a unit-specific or partial-unit basis. Any BTMG unit seeking to be designated in whole or in part as a wholesale resource must submit an interconnection request.

Tom Hyzinski, GT Power Group | © *RTO Insider*

BTMG rules were developed beginning in 2003 within the Behind-the-Meter Generation Working Group, Esterly said, and there has been limited review of the rules governing them since their development. Esterly said the OC in 2019 endorsed clarification updates to BTMG business rules focused solely on the reporting, netting and operational requirements of non-retail BTMG.

Esterly said the Tariff and Manual 14D updates are needed because of the increased development of distributed energy resources and load-serving entity requests for adjustments to network service peak load and obligation peak load for new BTMG.

The key work activities include providing education on existing BTMG business rules in the Tariff and Manual 14D related to status changes, Esterly said. Work also will include reviewing and identifying business rules related to status changes that would benefit from clarification or additional detail or that may conflict with existing rules.

The review includes:

- clarifying any relevant limitations or restrictions on market participation;
- clarifying market participation impact on the unit's ability to net against the load; and
- clarifying the paths for participation in PJM markets.

The committee will be asked to approve the issue charge at its October meeting. ■

— Michael Yoder

PJM PC/TEAC Briefs

Planning Committee

2020 Installed Reserve Margin Study Results

PJM is recommending an installed reserve margin (IRM) of 14.4%, down from 14.8% required in 2019.

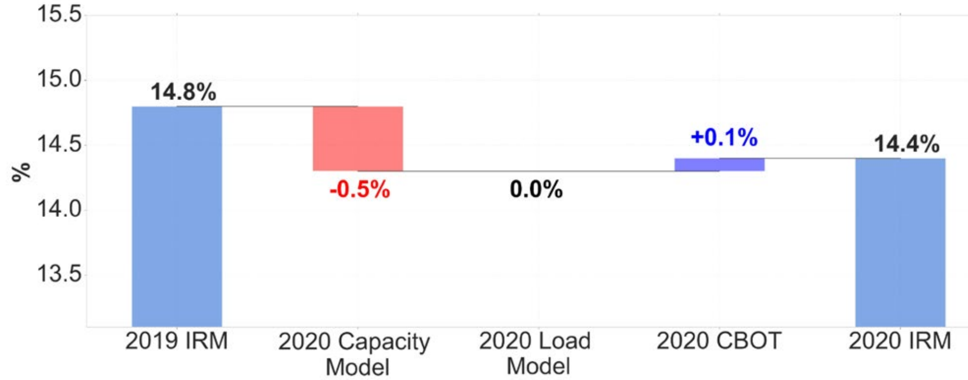
During the Sept. 1 Planning Committee meeting, PJM's Patricio Rocha Garrido reviewed the 2020 reserve requirement study (RRS) *results*, which determine the RTO's IRM and forecast pool requirement (FPR) for 2021/22 through 2023/24 and establishes the initial IRM and FPR for 2024/25. The results are based on the 2020 capacity model, load model and capacity benefit of ties (CBOT).

The 2020 capacity model is putting downward pressure on the IRM, with the average effective equivalent demand forced outage rate (EEFORd) of 5.78%, compared to 6.03% in the 2019 RRS.

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. 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, Garrido said, coming in at 1.0865 instead of 1.086 the previous year.



2020 IRM Waterfall Chart | *PJM*

Garrido said the study results will also be used in the 2022/23, 2023/24 and 2024/25 Base Residual Auctions (BRA). He said delays in the 2019 BRA for 2022/23 necessitated the use of data from the 2020 study.

The PJM and world load models used are based on the 2002-2014 period that were approved at the August PC meeting. (See "Load Model Selection," *PJM PC/TEAC Briefs: July 7, 2020*.) Analysis from the *2020 PJM Load Forecast Report* released in January was also used.

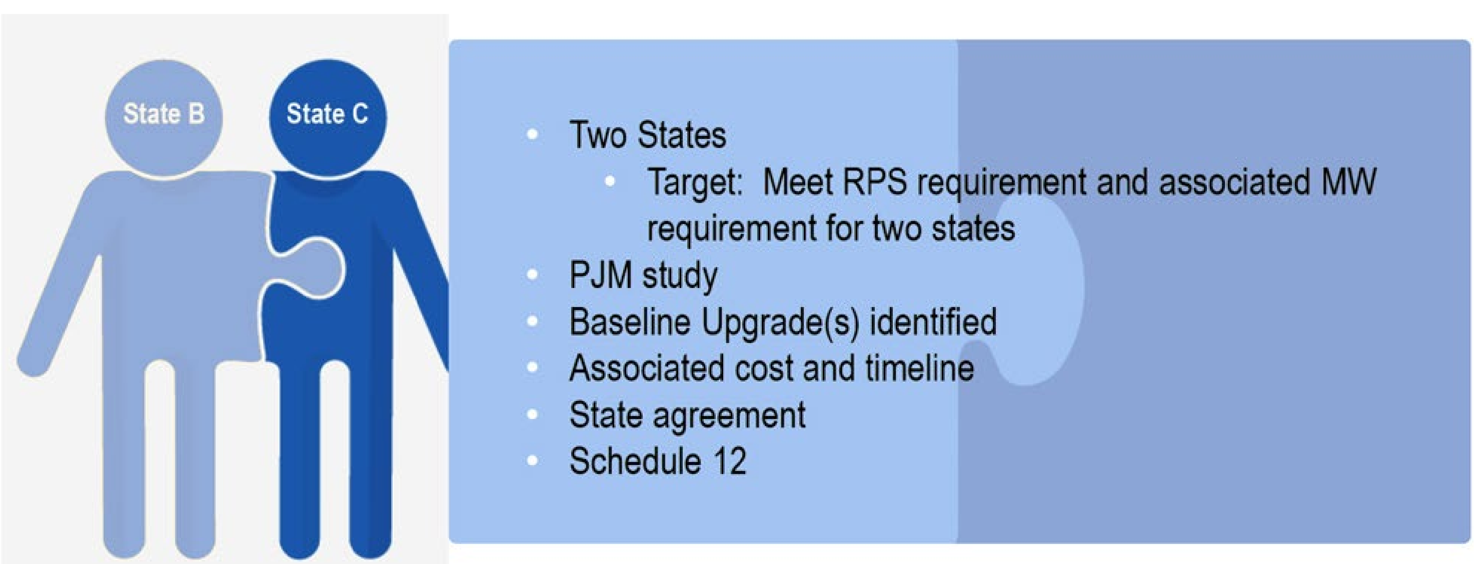
The PC will vote on the study results at its next meeting, with final votes at the Markets and Reliability Committee and Members Committee meetings in November.

Preliminary 2021 Capital Budget

Jim Snow of PJM reviewed the RTO's preliminary 2021 capital *budget*, which is set at $40 million, roughly the same amount as the 2020 budget.

The largest portion of the proposed budget is for current applications and systems reliability, Snow said, with $15 million earmarked for projects compared to $19 million in the 2020 budget.

Some of the proposed systems reliability projects include cybersecurity enhancements for monitoring and access of PJM's computer systems, automation and efficiency improvements for markets, and operations-related



Theoretical example – Two states one solution | *PJM*

PJM News

applications. Money is also set aside for the integration of eDART into PJM's standardized software tools and to provide enhancements to the application through upgrades.

Snow said the next largest budget expense is for facilities and technology infrastructure at $11 million. Projects include purchasing network, server and storage infrastructure equipment to replace obsolete equipment and replacing conference room equipment to enhance capabilities for on-site and remote participants at the PJM campus. Money is also allocated for the replacement of the Valley Forge, Pa., control center's below-grade-level cooling units and to add a backup cooling method.

Application replacements and retrofitting are proposed to be increased to $9 million in 2021 from $6 million in 2020. Projects include implementation of updated architecture to allow for future expansion of PJM's transmission network application system and the Next Generation Markets project, a multiyear partnership among PJM, MISO, ISO-NE and General Electric that began in April 2017 to transform the market systems architecture, technology and products. (See "nGEM Project Update," *PJM MIC Briefs: April 15, 2020*.)

Snow said the replacement of aging backup diesel generators for the control center building was deferred until a future budget. That project is expected to cost $5.4 million.

State Agreement Approach

Mark Sims of PJM provided an informational discussion and *update* on the RTO's "state agreement approach." FERC *approved* the approach in the RTO's first Order 1000 compliance filing in 2013, saying it was "supplemental to PJM's proposal to consider transmission needs driven by public policy requirements, and not needed for compliance." (See *PJM Dusts off 'State Agreement' Tx Approach*.)

The approach allows individual states or groups of states to submit a transmission project for study by PJM, even if it does not qualify as a reliability or market efficiency initiative under the RTO's Tariff. The project would be included in the Regional Transmission Expansion Plan (RTEP) as a supplemental project or baseline state public policy project — which could trigger a competitive solicitation — if the state(s) agree to pay for it.

Sims went through a theoretical example of a two-state solution under the approach. First a target project is identified that meets the renewable portfolio standards and associated megawatt requirements of the two states.

PJM would then model the generation in a study, and assumptions would be made to determine the best location for the generation and identify any needed baseline upgrades. Associated costs and a timeline for the baseline upgrades would then be created by PJM and would be documented in Schedule 12 of the Tariff.

Sims said a state can choose not to move forward with the approach at any time in the process.

Erik Heinle of the D.C. Office of the People's Counsel asked if there is a scenario in which PJM will play a "matchmaker" between two states looking to find a solution through the approach and what role the RTO envisions playing in the process moving forward.

Sims said the process is totally driven by the states, but PJM is willing to play a part in conversations between government entities. He said a big part of the RTO's role is education and instructing states on how the approach works.

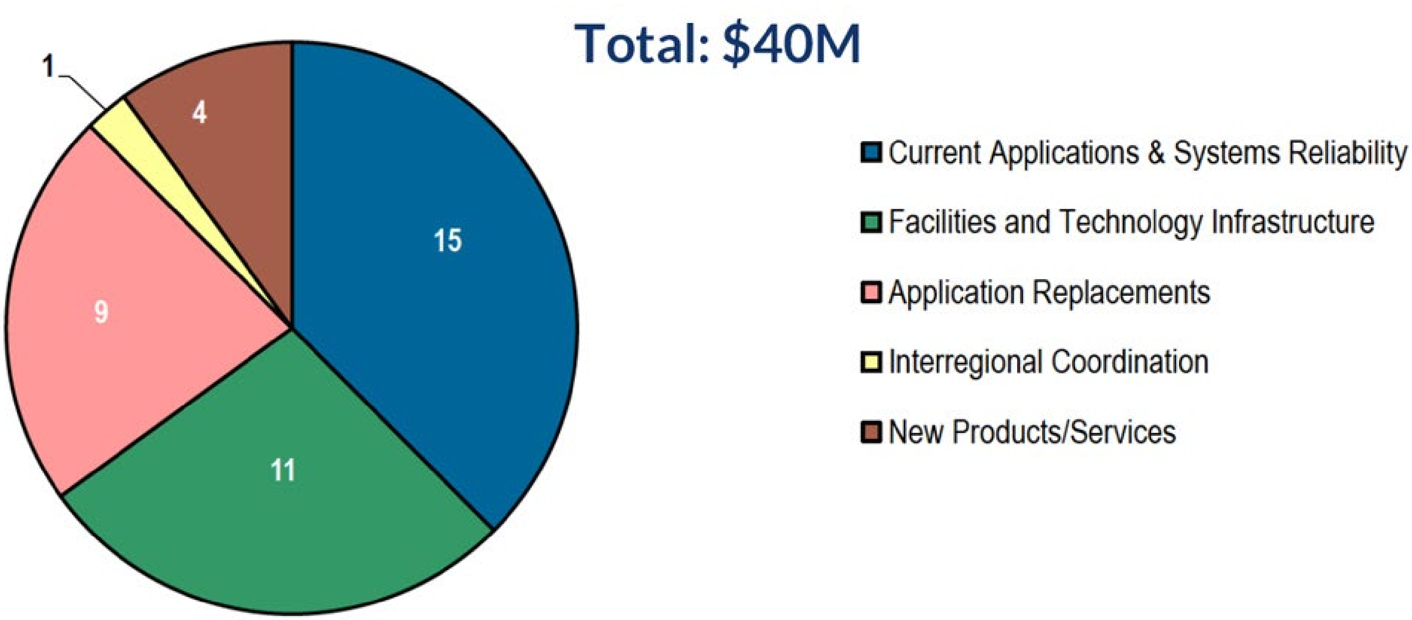
PJM does not intend to find the optimal solution for states, he said. Instead, the RTO will work with states to identify the assumptions based on their needs and the RPS requirement.

"We are ready and willing to have conversations," Sims said. "We're here for any states who approach us."

Transmission Expansion Advisory Committee

Market Efficiency Update

Nick Dumitriu of PJM *presented* the Transmission Expansion Advisory Committee with assumptions for the 2020/21 long-term market



Preliminary 2021 capital budget | *PJM*

PJM News

efficiency window, announcing that the RTO would post the preliminary base case on its website by the end of the week for stakeholders to examine.

Dumitriu said the base case is still not complete and some analysis has to be finished. He said the preliminary base case is being posted so that stakeholders can provide feedback to ensure the correct ratings and other data are included.

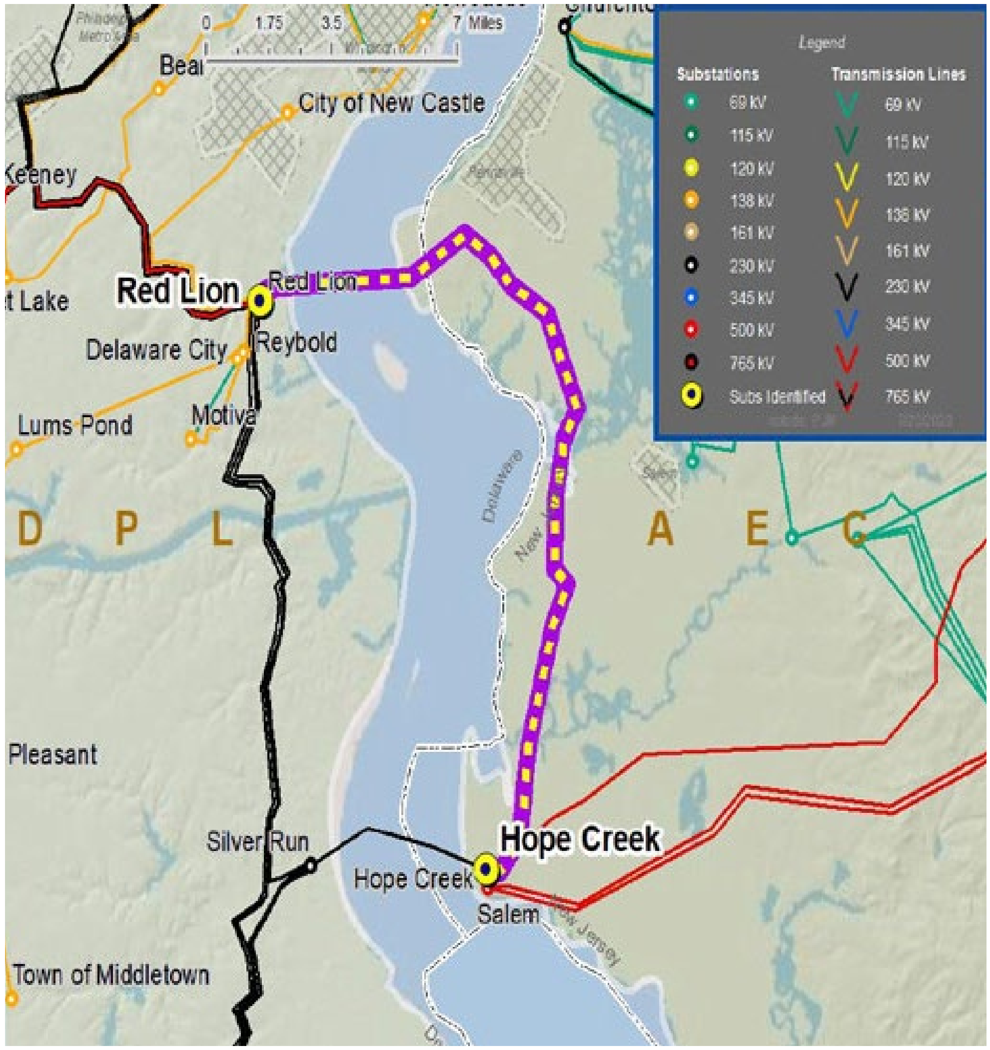
PJM will present the preliminary congestion drivers at the October TEAC meeting. The final base case and congestion drivers will be posted in December before the start of the 2020/21 long-term window in January.

Dumitriu said the base case power flow is consistent with the powerflow posted in the 2020 RTEP proposal window. The load forecast is based on the 2020 load forecast report, Dumitriu said, and the demand response is consistent with the same report.

The financial parameters for the preliminary base case are based on the Transmission Cost Information Center *spreadsheet*. The discount rate stands at 7.37%, Dumitriu said, and the levelized annual carrying charge rate is 11.82%.

Mark Ringhausen of Old Dominion Electric Cooperative asked how the annual carrying charge rate was determined. Ringhausen said that transmission owners with which his company interconnects have a "much higher" carrying charge.

Dumitriu said the number is tabulated from information contained in the Transmission Cost Information Center spreadsheet and is based on information from all TOs across PJM.



Public Service Electric and Gas and Delmarva Power & Light presented solutions to fix a line running from the Hope Creek Nuclear Station that continues to experience faults. | *PJM*

Hope Creek Line

Public Service Electric and Gas and Delmarva Power & Light presented solutions to help fix a line running from the Hope Creek Nuclear Station that continues to experience faults.

Esam Khadr of PSE&G presented needs and a *solution* for the supplemental project involving the 500-kV 5015 Red Lion line that runs from the nuclear plant in New Jersey to the Red Lion substation in Delaware. Khadr said the line has experienced nine faults in the last 10 years because of birds and lightning strikes, including two faults in April.

The line is currently protected using power line carrier relaying, additional simulation testing has revealed a more secure and reliable method for fault detection, and isolation is required to avoid potential overtrips, Khadr said.

Multiple towers on the line are only accessible by boat, Khadr said, so more accurate fault location methods are required. He said the 5015 line is critical to the operation of Hope Creek and the Salem Nuclear Power Plant.

The proposed solution calls for upgrading relaying of the 5015 line at Hope Creek and using existing fiber optic paths for primary and backup line protection. The estimated cost of the project is $1.2 million and is projected to be in service by March 2021.

Delaware Deputy Public Advocate Ruth Ann Price asked why the fault problem was not addressed when more than $250 million in stability upgrades to Artificial Island in New Jersey were planned in recent years. (See *Artificial Island Cost Dispute is Over – Almost*.) Price said it seemed "interesting" that when the Artificial Island upgrades were being discussed that the line failure issue was not brought up.

Alex Stern, director of RTO strategy for PSEG Services, explained that PJM originally chose an Artificial Island project that would have dealt with the fault issue, but the Board of Managers subsequently rescinded that decision and went with a different approach.

"It was still needed to be done at some point, and with two incidents during the pandemic, it elevated the concern," Stern said.

Delmarva's Steve Zelvis presented a proposed *solution* for his company's portion of the project. It includes removing a wave trap at Red Lion and reconnecting communication over the existing fiber optic path. The estimated cost of the project is $200,000.

Price said the cost of Delmarva's solution was fair. "The cost is within the scope of reasonableness," she said. ■

— Michael Yoder

PJM News

PJM Operating Committee Briefs

Intelligent Reserve Deployment Rollout

PJM's Mike Zhang on Thursday provided the Operating Committee with an update on the planned rollout of the intelligent reserve deployment (IRD), a security-constrained economic dispatch (SCED) case simulating the loss of the largest generation resource. Approval of the case would trigger a spin event either in the Mid-Atlantic Dominion zone or throughout the RTO, Zhang told the committee.

The IRD will function mostly as a normal SCED case, Zhang said, with an economic dispatch based on all the same real-time inputs that the existing cases get, including constraints and load. But because it's deploying units for a spin event, Zhang said some aspects of the case will be done differently.

The case will add the megawatts of the largest contingency to the load forecast at the zonal level to simulate the unit loss, Zhang said, and will also be able to deploy condensers and other inflexible Tier 2 resources cleared for energy. Finally, the IRD procures additional resources to meet the new largest contingency.

Zhang said the IRD will be available to PJM dispatchers with no lag time waiting on a case to solve. He said it will more accurately price the deployment of reserves in a spin event because currently, the prices at the time of the event don't align with what is actually happening operationally on the grid.

Because SCED is being used, Zhang said, dispatchers can accurately deploy reserves and not create other operational issues. He said enough reserves generally exist at the beginning of a spin event, so PJM wants to make sure the reserves are deployed accurately without calling on excess reserves.

The RTO is looking to implement the IRD in late September or October for dispatchers.

Several stakeholders asked for more discussion on the issue at future OC meetings.

Independent Market Monitor Joe Bowring presented questions for PJM to consider when addressing the issue in future meetings. He asked if the loss of the largest generation unit in a zone is the actual trigger for any spin event and whether PJM should determine whether a targeted amount of spinning reserves in specific locations should be called when there is a spin event rather than an "all call" of all spinning reserves in every case, which might prompt excess reserves to be deployed. He said when looking at the causes of spin events, the loss of the largest unit in a specific zone is rarely the trigger for the event.

Bulk Power System Executive Order

Craig Glazer, PJM | © *RTO Insider*

Craig Glazer, PJM's vice president of federal government policy, provided an update on the Department of Energy's efforts to implement President Trump's *Executive Order 13920* to remove grid equipment connected to "foreign adversaries," such as China. The presentation included a summary of the ISO/RTO Council's response to DOE's request for information on the bulk power system.

The May 1 order declared a national emergency regarding foreign threats to the BPS and imposed restrictions on the purchase of equipment from suppliers suspected of connections with foreign adversaries. (See *Trump Declares BPS Supply Chain Emergency*.)

Glazer called it a "pretty sweeping order" impacting both existing equipment and future equipment installation. He said it's already difficult to find computer hardware and software that doesn't have some component with connections to China.

"There's a lot of industry concern about this because of its sweeping nature," Glazer said.

The DOE rules regarding the executive order are due to be completed by Oct. 1. The department issued a *request for information* July 8 to solicit input from industry and the public on the order.

Glazer said the IRC recently filed *comments* with DOE, indicating that it believed the order's language was too broad and that the scope of the problem needs to be better defined and narrowed. The council also requested that the department conduct a risk assessment to determine the impact on the grid of removing foreign components and the difficulty of replacing them.

"This is actually a big deal but has somewhat flown under the radar screen," Glazer said.

PJM Aug. 3 Technical Issues Update

Sean McNamara of PJM *discussed* technical issues that temporarily caused several of the RTO's market applications, tools, website and external email to be inaccessible for as much as a week last month.

McNamara said PJM and a vendor-initiated system updates after business hours on Aug. 3. Following the updates, the RTO's services were unexpectedly affected and taken offline.

PJM personnel and the vendor immediately began working to resolve the technical issues, McNamara said, including performing overnight tasks.

McNamara said external email was restored by Aug. 5. While it was unavailable, he said, stakeholders were still able to communicate with PJM through the member relations help line and the information technology operations center.

Most market applications and tools were restored and available by Aug. 7, McNamara said, and the remaining tools were restored and fully functional by Aug. 10.

McNamara said the reliability of the grid was unaffected by the problems. PJM's markets were restored quickly and have been available and running without interruption since the Aug. 3 incident.

PJM conducts regular drills for events similar to the system maintenance issue, McNamara said, which prepares the RTO to respond quickly to unforeseen problems. The RTO is currently examining what triggered the event and will implement corrective action to avoid the possibility of a reoccurrence during system maintenance work in the future.

Manual First Reads

Two first reads of PJM manual changes were presented at the OC.

Darrell Frogg of PJM *reviewed updates* to Manual 14D: Generator Operational Requirements as part of the periodic review. The updates include clarifying, administrative and substantive changes to the manual.

Frogg said the substantive change relates to section 7.5.1, the cold weather operational exercise, which will no longer be administered by PJM and instead be handled by the generation owners. The RTO is recommending that generation owners self-schedule testing of resources that have not operated in eight weeks leading up to Dec. 1.

Vince Stefanowicz of PJM *reviewed updates* to Manual 10: Pre-Scheduling Operations for the periodic review. The changes include several clarifying changes but nothing substantive, he said.

The OC will be asked to endorse the manual changes at the October meeting. ■

— Michael Yoder

PJM Monitor Challenges MBRAs over Market Power

By Rich Heidorn Jr.

PJM's Independent Market Monitor has opened another front in its bid to strengthen the RTO's market power rules, filing challenges to the renewals of market-based rate authorizations (MBRAs) in 14 dockets.

The Monitor said the RTO's current market power mitigation rules are insufficient to support the reauthorizations, reiterating arguments it made in its State of the Market reports for PJM and its February 2019 complaint alleging that the capacity market seller offer cap (MSOC) allows market power by some sellers (EL19-47).

Barring new rules, the Monitor said, FERC should require capacity market sellers to offer their resources at or below the "competitive capacity offer" — currently the avoidable-cost rate adjusted for expected Capacity Performance (CP) penalties and bonuses.

Energy market offers should be capped at or below the defined cost-based offer and required to submit operating parameters at least as flexible as the market's defined unit-specific parameter limits, the Monitor said.

The Monitor filed protests Aug. 28 and 31 challenging triennial MBRA renewal requests by:

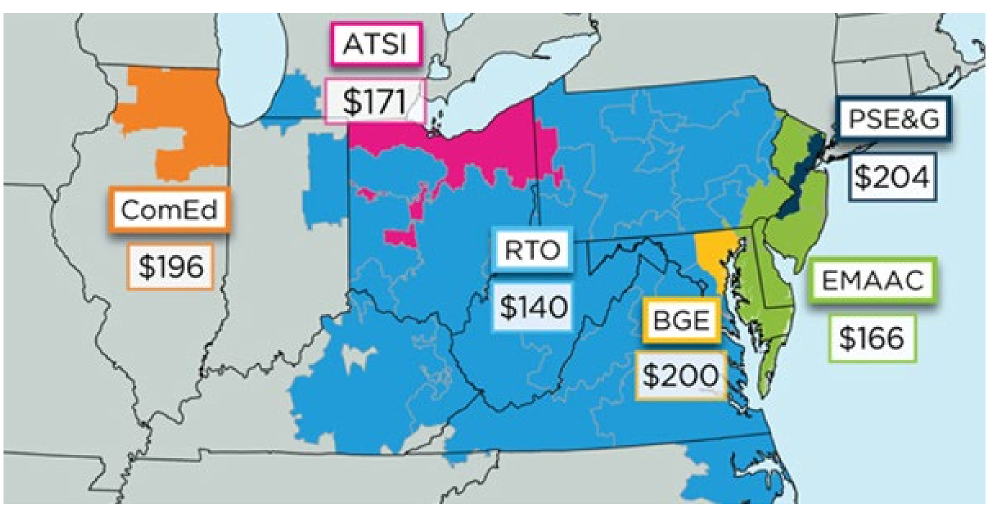
- Calpine Bethlehem, et al. (*ER10-2051*);
- Wheelabrator Baltimore, et al. (*ER13-1485*);
- TAQA Gen X, Red Oak Power and Bayonne Energy Center (*ER15-289*);
- LQA, Tenaska Power Services, et al. (*ER16-733*);
- Cube Yadkin (*ER16-2278*);
- Macquarie Energy (*ER18-2264*);
- Moxie Freedom (*ER20-2276*);
- Longview Power (*ER10-1556*);
- NRG Power Marketing, et al. (*ER10-2265*);
- Commonwealth Chesapeake and Hickory Run Energy (*ER10-3078, ER19-2564*);
- Talen Energy Marketing, et al. (*ER15-2013*);
- Radford's Run, et al. (*ER17-1438*);
- Carrol County Energy (*ER17-1609*); and
- Kestrel Acquisition (*ER18-1106*)

The Monitor noted that Order 861 allows intervenors to challenge MBRA applicants' claims that they do not post horizontal market power concerns. "Analysis of PJM markets shows that all PJM sellers have the potential to have and exercise local market power at any time based on transmission constraints that may arise in the PJM market for a variety of reasons," it wrote.

While PJM's energy market results are "generally competitive," the Monitor said, market power mitigation is often inadequate.

"Some sellers that fail the structural market power test — the three-pivotal-supplier test (TPS) — are able to set prices with a substantial markup over their cost-based offer," it said. "Some sellers that fail the TPS test are able to operate, set prices and collect uplift payments with operating parameters that are less flexible than their defined parameter limits."

> **"Analysis of PJM markets shows that all PJM sellers have the potential to have and exercise local market power at any time based on transmission constraints that may arise in the PJM market for a variety of reasons."**
>
> —PJM Independent Market Monitor



PJM's Independent Market Monitor contends ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 Base Residual Auction because of economic withholding encouraged by an inflated market seller offer cap. | *PJM*

No Action

FERC has not responded to the Monitor's complaint over the MSOC, and there has been no substantive action in the docket since May 2019, when the IMM responded to PJM's request to dismiss it.

PJM said the Monitor had failed to provide evidence that the cap — approved four years prior as part of the CP construct — and the results of Base Residual Auctions (BRAs) suddenly became unjust and unreasonable. (See *PJM: Dismiss Monitor's Offer Cap Complaint*.)

The RTO said the commission's order approving CP "explained that the default MSOC is just and reasonable because it reflects the amount that a competitive resource would accept to be committed as a capacity resource."

The Monitor contends that ratepayers were overcharged by $2.7 billion (41.5%) in the 2018 BRA because of economic withholding encouraged by an inflated MSOC. "The assertion that the system conditions have not 'drastically changed' since 2015 has no basis in fact and would surprise any objective observer of PJM markets," it wrote in its answer. (See *Monitor Defends Offer Cap Complaint*.) ■

Gen Owners Balk at Change to PJM Black Start Rates

By Michael Yoder

Tasley, a single-unit 33 MW industrial gas turbine that began commercial operation in 1972 in Tasley, Va., is a black start-capable unit. Calpine acquired Tasley in 2010 as part of its purchase of the Conectiv Energy assets. | *Calpine*

A contentious discussion regarding updates to the PJM Tariff's black start capital recovery factor (CRF) table led stakeholders to issue strong challenges to the RTO and the Independent Market Monitor at the Operating Committee meeting Thursday.

Paul Sotkiewicz of E-Cubed Policy Associates blasted the stakeholder process regarding the development of the CRF, saying it "was handled extremely poorly by PJM." Sotkiewicz said that although the *problem statement* and *issue charge* endorsed by the OC in May were supposed to look at CRF on a "prospective basis" with future *black start units*, the PJM and Monitor solution packages would apply the CRF to black start units already in service.

Sotkiewicz said generation owners with black start units are now finding themselves "absolutely surprised and flabbergasted" that units that have been in service for years and went through the bidding process may "potentially have to take a haircut" on previously promised benefits.

He said an "uncomfortable point for PJM" may be coming if stakeholders decide to endorse the CRF table for black start because it could set off a wave of revisions of the CRF in other places in the Tariff. If revisions are going to be done for black start, he said, it could also lead to revisions for the Reliability Pricing Model (RPM) auctions as well.

"Is that a fight that PJM is willing to take on at FERC and with generation owners?" Sotkiewicz asked. "I'm not sure that's the best use of our time right now, given all the other problems with RPM going forward."

Craig Glazer, PJM vice president of federal government policy, said that when the issue of updating the CRF came up for discussion, the RTO intentionally included it in the black start options *matrix* as needing stakeholder input. Glazer said the stakeholder input, along with dialogue with the Monitor, was taken to help formulate the proposals put forward for the CRF table update and to have it apply to existing black start resources.

Sotkiewicz said entertaining determinations that the updated CRF table would apply to existing black start resources was procedurally out of order and was not part of the issue charge endorsed by stakeholders.

"The fact that PJM is negotiating behind closed doors with the Market Monitor on this and trying to fast-track this is doubly troubling," Sotkiewicz said.

Black Start Progression

Work on an initiative that could tighten fuel requirements for black start resources was put on hiatus in March to allow the RTO to do additional analysis on its potential benefits. (See *PJM Backs off Black Start Fuel Rule*.)

In the interim, PJM decided to focus on the CRF and three other areas in the Tariff that the RTO said were in need of updates: testing requirements for black start resources not compensated through Schedule 6A; black start unit substitution rules; and black start termination rules. (See *PJM Eyeing New Black Start Changes*.)

The issue charge won endorsement at the May OC meeting, and stakeholders have been working for several months on the issues. (See "Black Start Issue Charge Endorsed," *PJM Operating Committee Briefs: May 14, 2020*.)

The CRF update has turned out to be the most controversial issue for stakeholders. The problem statement said that the current CRF is based on assumptions that do not reflect recent tax law and interest rate changes. PJM said it wanted to create a way to automatically update the CRF table to remain consistent with future tax law changes.

The problem statement also noted that current black start units receiving the capital cost recovery rate in Schedule 6A of the Tariff and units already awarded in recent black start requests for proposals will continue with the commitment period and CRF rates as documented in the Tariff.

3 Proposals

Becky Davis of PJM provided a *first read* of the PJM solution package at the OC meeting.

Davis said PJM is proposing future updates to CRF to be calculated at the time of the black start unit's in-service date. The CRF would be calculated using depreciation as applicable under the tax code changes in the Tax Cuts and Jobs Act of 2017.

Other calculation points include:

- the current federal tax rate (updated annually);
- the average state tax rate (updated annually);
- the debt interest rate (updated annually);
- a return on equity of 12%;
- 50% equity;
- 50% debt; and
- a five-, 10-, 15- and 20-year capital recovery period based on unit age at the time of the unit entering black start service.

Monitor Joe Bowring provided a *first read* of the IMM solution package, which mirrors much of the PJM package.

Bowring said the CRF table was created in 2007 as part of the RPM capacity market

PJM News

PJM Monitor Joe Bowring | © *RTO Insider*

design. He said the CRF table "provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old units would be making substantial investments related to pollution control." The same CRF table was also used in the black start rules.

Bowring said the CRF table includes assumptions that are no longer correct and that the CRF values are significantly higher than they should be under the lower corporate tax rate, leading to overcompensation for units.

The Monitor is proposing two CRF tables: one reducing the tax rate to reflect that units existing prior to the 2017 tax law saw their tax rate decrease without changes to the depreciation rules; and a second for black start units that came into service after the new law went into effect and benefited from new depreciation provisions and a lower corporate tax rate. In addition, the Monitor proposes that black start resources recover their costs over either a 10- or 20-year period and have a continuing commitment to provide black start service.

The original CRF table sets black start terms ranging from five years for units 16 years or older to 20 years for units five years and younger.

Bowring said overcompensation amounts vary with the project investment and the CRF recovery period. He said a post-2017 black start unit with an investment of $21 million to which the tax law applied would receive $840,000 per year in excess compensation, or $16.8 million over a 20-year recovery period.

A post-2017 black start unit with an investment of $21 million to which the lower tax rate applies would be overpaid by $2.6 million per year, or $13.4 million over a five-year recovery period.

Bowring said total overcompensation, if the CRF rules are not modified, for both pre- and post-2017 units over the life of their compensation periods would be $108.7 million.

Black Start Owners' Response

Michael Borgatti of Gabel Associates *presented* the potential impacts of the proposed black start rate changes on behalf of an anonymous coalition of black start resource owners.

Borgatti said the generation owners believe the proposed changes to the black start capital recovery rate should only apply prospectively. He said limiting the changes to prospective application would avoid "unnecessary litigation over retroactive ratemaking concerns."

Borgatti said he was authorized by the stakeholders he represents to notify PJM that if the RTO's or Monitor's proposed changes to the CRF table had been applied at the time of their black start units coming online, they would not have submitted bids. He also said that if the changes are endorsed, several of the generation owners will "strongly consider terminating their black start agreements at the earliest possible interval."

"You're looking at entities now that are committed to providing this service who would not have made that commitment under the proposal out here," Borgatti said.

Bowring said the Monitor understands the objections being made by stakeholders, but he said he doesn't believe it's the responsibility of PJM to make the final decision on the CRF updates. He said that ultimately the final decision should be made by FERC.

"It's not our decision to make, but at the same time, we can't ignore it," Bowring said. "Regardless of what the stakeholders decide, I believe we have the responsibility as the Market Monitor to take it to the commission and let them decide. If they decide against us, that's fine." ■

SPP Expands its Western RC Footprint

WEIS Tariff Work also Completed

By Tom Kleckner

Still in its first year as a reliability coordinator in the Western Interconnection, SPP last week announced it will add 3.45 GW of generating capacity to its RC footprint in 2021.

The RTO on Sept. 1 said it will add eight generating resources that are part of *Gridforce Energy Management's* balancing authority in Washington, Oregon, Arizona, and New Mexico, effective April 1.

Gridforce operates primarily as a BA for independent power producers and electric utilities, but the company offers a range of other operational services. Three of its Arizona BAs are currently in SPP's RC footprint: Griffith Energy, Arlington Valley and New Harquahala Generating Co.

Gridforce President C.J. Ingersoll said the company's continued relationship with SPP will help its expansion and growth.

"Gridforce will continue to work with clients that receive reliability coordinator services from both SPP and [CAISO's] RC West," he said in a *press release*. "We are looking forward to continued focus on reliable system operations and the benefits of working with highly capable RCs."

SPP launched its Western RC service in December 2019 for Gridforce and 14 other customers. It has been an RC provider in the Eastern Interconnection since 1998.

"We're happy to see our reputation as a service provider of choice growing in the West," said Bruce Rew, SPP's senior vice president of operations. "We want the chance to prove ourselves just as we've done for Eastern utilities."

Stakeholders Complete Work on WEIS Tariff

SPP is also developing a real-time balancing market in the West that is scheduled to launch Feb. 1. On Wednesday, the RTO's Western stakeholders approved a final necessary revision request as staff work to refile with FERC a proposed Tariff for its Western Energy Imbalance Service (WEIS).

The measure (*WRR6*) completes the RTO's response to a series of issues the commission raised in rejecting its first attempt (*ER20-1059, ER20-1060*). (See *FERC Rejects SPP's WEIS Tariff*.)

WRR6 provides that SPP will include constraints in its economic dispatch engine to use the combined transmission capability made available by market participants (MPs) and participating BAs on transmission facilities within a participating BA area or on transmission facilities used to transfer energy between participating BAs.

The revision was a holdover from the previous week, when the Western Markets Working Group and Western Markets Executive Committee held two joint meetings. The stakeholder groups were able to pass three other WRRs. (See *SPP Stakeholders Agree on WEIS Tariff Changes*.)

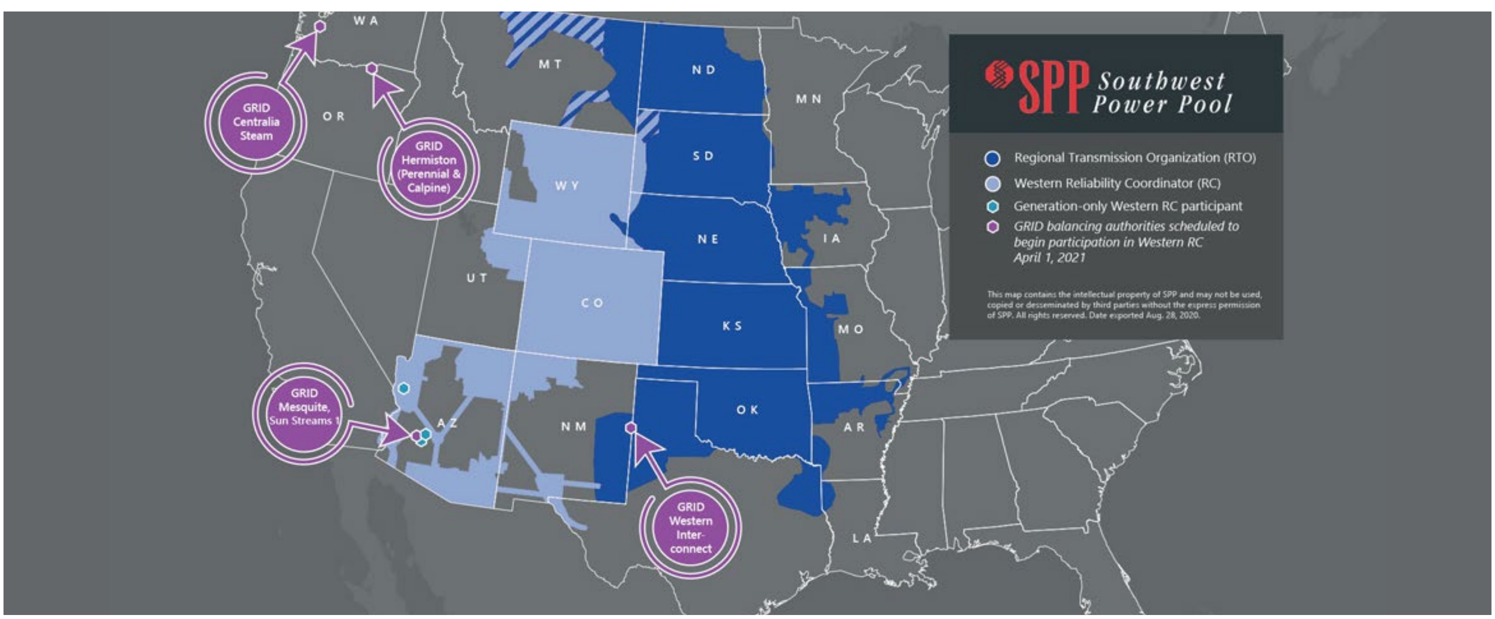
Both groups passed WRR6 unanimously after agreeing on language that clarified that "SPP, in its capacity as market operator," would, before constraining market dispatch, receive communication from joint dispatch transmission service providers and other MPs.

FERC said any future WEIS market proposal "should include the mechanisms or agreements that will ensure that the SPP WEIS market respects the transmission capacity of nonparticipating entities with appropriate constraints in the [security-constrained economic dispatch]."

Much of the debate centered on whether to capitalize "market operator," as it is not defined in the WEIS' Tariff or protocols, and how Robert's Rules of Order governed WRR6 motions from the week before.

"I'll be an expert on Robert's Rules one day," joked Basin Electric Power Cooperative's Valerie Weigel, the working group's chair.

SPP staff said they likely need the Board of Directors' authorization to refile the Tariff. They plan to first meet with FERC staff for a prefiling meeting later this month before scheduling a board meeting. ■



SPP's Western RC footprint will expand in April 2021. | *SPP*

SPP News

SPP Briefs

Staff to Begin Returning to Office in Oct.; Meetings Remain Virtual

SPP said last week it will begin allowing staff to return to its Little Rock, Ark., corporate headquarters in October, although the move is dependent upon "our community meeting certain milestones for health and safety."

The transition back to the office is scheduled to begin Oct. 5. SPP will used a phased approach, with 20% of the staff returning at a time. The grid operator in mid-March sent home its non-operations personnel, though some individuals have returned in recent weeks.

"We will continue best practices to keep our employees healthy and provide our essential services," CEO Barbara Sugg said in an *email* to stakeholders.

The RTO's Board of Directors and other committees will continue to meet virtually through at least January. The board and Markets and Operations Policy Committee last met in person in January.

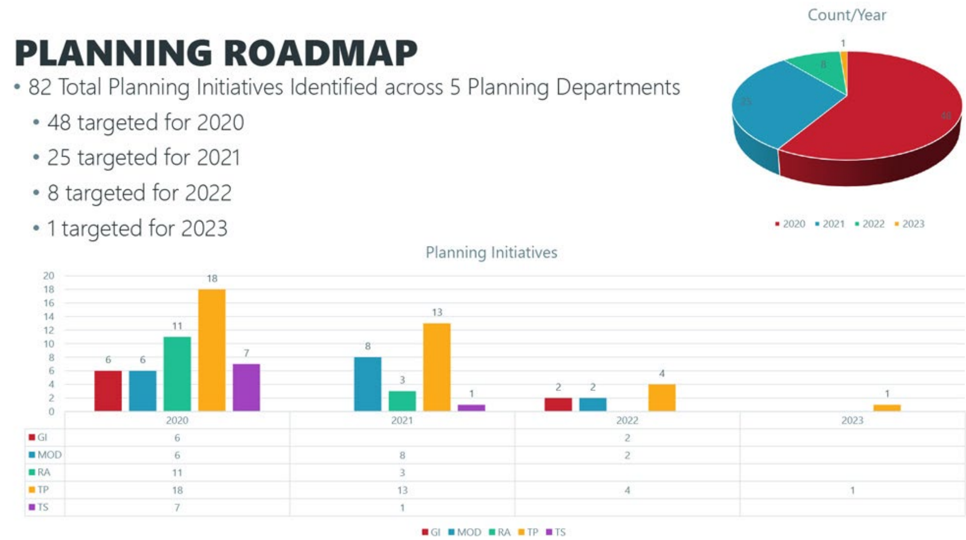
The White House Coronavirus Task Force last week *placed Arkansas in the "red zone,"* which recommends indoor dining be capped at 25% capacity and that bars be closed. The state on Friday *reported* a record 1,094 confirmed COVID-19 cases and 12 deaths, raising its totals to 64,174 and 873, respectively.

Sugg also took time to remark on SPP's "collective progress" this year. Load has returned to pre-pandemic levels, while staff and stakeholders continue to prepare to launch the RTO's Western Energy Imbalance Service market and conduct other strategic initiatives.

"Together we have navigated temporary and lasting changes to the way we work. … I know together, we stand ready to meet new energy challenges that arise," she wrote.

Sugg said SPP is "working through the aftermath of Hurricane Laura," which affected its footprint and those of neighbors ERCOT and MISO. The RTO has also supported western grid reliability by coordinating with CAISO, members and customers to ensure resources are available.

"We learn from each event we experience and take the opportunity to improve our own processes while also communicating with our peers about lessons learned from their perspective," she said.



SPP's transmission-planning roadmap extends into 2023. | *SPP*

"Take good care, and please wear a mask," Sugg said, in closing her email.

SPC Takes Look at Tx Planning

The Strategic Planning Committee is forming a task force — cumbersomely named the Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) — to evaluate all of SPP's transmission planning and applicable cost allocation processes.

SCRIPT comprises 11 SPC and Members Committee representatives and will add a soon-to-be-named member from the Regional State Committee. Chaired by Director Mark Crisson, the group will report to the board and provide updates to the three committees.

"This is going to be a really important initiative that has the potential to have a major strategic impact on the organization," Crisson said during an Aug. 31 *SPC education session* on transmission planning.

During the session, SPP staff ran the committee through its planning initiatives and processes, including:

- centralized coordinated process and integrated transmission planning;
- cost-allocation alignment;
- decision quality;
- risk-based planning;
- regional fuel mix;
- generator interconnection (GI) improvements; and
- model reduction.

SPP has seven planning departments. Staff conduct seven different planning studies, as well as compliance, seams and *ad hoc* studies. They are also responsible for resource adequacy analysis and model builds.

SCRIPT is expected to consider options to redesign those processes and produce a report with high-level recommendations by September 2021.

"We need to see how we can step back and integrate all the transmission functions we have," said Casey Cathey, SPP's director of system planning. "Everything we do has a reason. We have a reason for a GI process. We have a reason for reliability planning. The question is, how can we do it better?"

Staff are working on a planning roadmap to be presented to the board in January. SCRIPT is an important first step, Vice President of Engineering Antoine Lucas said.

"We will be looking for the SCRIPT to prioritize those initiatives and drive solutions through the working groups in an effective manner," he said.

The SPC has also created the *Energy Storage Resource Task Force* to determine the strategic use of storage as capacity and in potential support of the grid. The task force is scheduled to complete its work in the first quarter of 2021. ■

— Tom Kleckner

SPP News

GridLiance Acquires Tx Facilities in Kansas

By Tom Kleckner

GridLiance said last week its High Plains subsidiary has acquired a 65% ownership stake in the 69-kV transmission system and related substation equipment of the city of Winfield, Kan.

The transaction marks GridLiance's first co$_2$ ownership of transmission assets with a municipal utility under a development agreement with Kansas Power Pool, a municipal energy agency that provides energy and transmission services to Winfield and 30 other municipalities in Kansas.

"The successful closing of this transaction is an important step in bringing improved transmission reliability to Winfield customers and the region," GridLiance CEO Calvin Crowder said in a *press release*. "It is another example of our long-term commitment to invest in the electric grid and ensure the fair treatment of all transmission consumers."

The city will retain 35% ownership in the facilities and will be responsible for their maintenance. Winfield will continue to own its electric distribution assets and continue to provide retail electric service in return for a franchise fee and economic development and community support funds from GridLiance. Financial terms of the deal were not announced.

GridLiance substation | *GridLiance*

The Dallas-based independent electric utility holding company and Winfield have already begun to relocate transmission lines damaged by years of flooding on the Walnut River. The work is expected to be completed by the end of the year.

"Joining forces with GridLiance will ensure we will continue to [provide reliable electric service] for the long term," Winfield Mayor Phil Jarvis said. "We are already seeing the benefits of our collaboration with GridLiance."

The transaction was completed once FERC in late August accepted SPP Tariff revisions adding an annual transmission revenue requirement reflecting GridLiance High Plains' addition as a joint owner of Winfield's transmission facilities (*ER20-2195*).

The acquisition is GridLiance's second of the year. In February, its gained access to the MISO system when FERC approved GridLiance Heartland's purchase of Vistra subsidiary Electric Energy Inc.'s ownership in six transmission lines and two substations in Illinois and Kentucky. (See *GridLiance Gains Entry into MISO*.) ■

SPP News

FERC Affirms its Jurisdiction over Tri-State G&T

Order Pre-empts Colorado Regulators' Authority

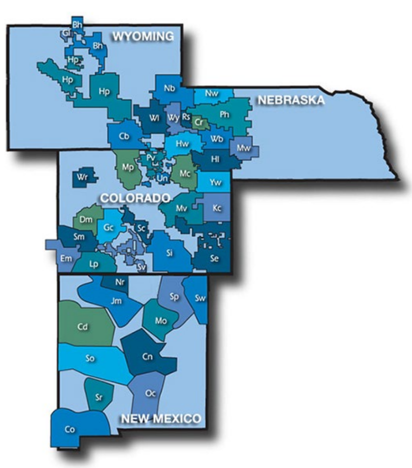
By Tom Kleckner

FERC on Aug. 28 affirmed that it has exclusive jurisdiction over Tri-State Generation and Transmission Association's rates and member exit charges, one in a flurry of orders that day related to the Colorado-based cooperative (*EL20-16*).

The order pre-empts the Colorado Public Utilities Commission's jurisdiction over Tri-State and would negate an exit-fee methodology proposed by co-op members United Power and La Plata Electric Association (LPEA). FERC in June accepted Tri-State's proposed contract-termination payment methodology and set hearing and settlement judge procedures, but a Colorado administrative law judge in July *recommended* that regulators approve the members' methodology. (See *Colo. ALJ Proposes $235M Exit Fee for United Power*.)

Tri-State became FERC-jurisdictional in March, when the commission recognized its status following last year's addition of MIECO, a wholesale energy services company that provides natural gas to the co-op, as its first non-utility member. (See "Ruling Permits Tri-State to Become FERC Jurisdictional," *SPP FERC Briefs: Week of March 16, 2020*.)

In its order last month, the commission said that, after "further consideration," it was modifying the March order to find that Tri-State's assessment of an exit charge "constitutes a commission-jurisdictional rate subject to our exclusive jurisdiction."



Tri-State's service territory includes 46 companies, soon to be 45, in the Rocky Mountains. | *Tri-State G&T*

Tri-State's headquarters in Westminster, Colo. | *Ludvik Electric*

FERC concluded that, as a result, the Colorado PUC's jurisdiction over complaints regarding Tri-State's exit charges "is pre-empted as of Sept. 3, 2019," the date the co-op admitted MIECO.

"This is a monumental decision for our members and Tri-State, and allows us all to move forward in our clean energy transition with much more certainty," Tri-State CEO Duane Highley said in a *statement*.

Tri-State CEO Duane Highley | *Tri-State G&T*

Highley said FERC was the "appropriate regulatory commission to consider these important issues."

"At the FERC," he said, "each of our members, no matter in which state they are located, can participate fully, have a voice and be treated equally on wholesale contract and rate matters."

The commission also reaffirmed that Tri-State's addition of new members was lawful under the Federal Power Act. It rejected United's and LPEA's claims that adding MIECO violated the law.

In a separate order, FERC also dismissed the members' rehearing requests (*ER20-1559*). It also sustained Tri-State's filed rate schedules in additional rehearing requests by United and the Sierra Club (*ER20-689, et al.* and *ER20-676, et al.*).

FERC to Investigate Tri-State Policies

FERC also found that Tri-State's use of fixed-cost equalization in its policy and rate is consistent with federal law and agreed with the cooperative's use of net metering for energy storage projects, rejecting United's and Sierra's claims and setting the matters for hearing (*EL20-66*).

The commission said Tri-State's policy reflects "the cost consequences that follow from the choice made by [qualified-facility] sellers to sell their power directly to Tri-State's utility members rather than to Tri-State under the transmission option." Referring to precedent set by Order 69, FERC said fixed-cost equalization "is simply a billing mechanism for implementing the avoided-cost pricing for full-requirements contracts."

While FERC held the settlement judge procedures in abeyance, it also opened FPA Section 206 investigations into whether two Tri-State board policies, a rate schedule and the member project contracts are just and reasonable. It said the policies, rate schedule and contracts raised issues of material fact that cannot be resolved based on the record before it.

One policy describes each member's option under its wholesale electric service contract to use self-owned or -controlled distributed or renewable generation resources to serve up to 5% of its annual requirement. The second addresses Tri-State's purchases of power from QFs and sets the terms for Tri-State's recovery of lost revenue (fixed-cost equalization) when a utility member's QF power purchases and its non-QF self-supply power exceed the 5% threshold.

The rate schedule in question sets forth the methodology for calculating billing adjustments due to Tri-State under the two board policies. ■

SPP News

FERC Rejects SPP's Zonal Planning Criteria

Proposal was 1 of 21 HITT Recommendations

By Tom Kleckner

FERC on Thursday rejected SPP's proposed Tariff revision to develop uniform local transmission planning criteria, siding with stakeholders who argued they would be unduly discriminatory or preferential (*ER20-2334*).

GridLiance High Plains, Tri-County Electric Cooperative, Kansas Power Pool and a group of eight cooperatives and municipalities protested the filing, which proposed to use zonal planning criteria to evaluate the need for zonal reliability upgrades in SPP's regional transmission planning process.

The RTO proposed that the network customer with the zone's largest total network load would designate each year a transmission owner within the zone as the facilitating TO. That TO would develop a single set of zonal planning criteria, conducting open meetings with the zone's other TOs and transmission customers taking long-term service within that zone.

All TOs within the zone would apply the zonal planning criteria "comparably" to all the zone's load.

SPP has 18 transmission pricing zones, 10 of which comprise multiple TOs. Currently, each TO submits its own local planning criteria to the RTO, which then uses its regional transmission planning process to determine whether a reliability violation requiring new reliability upgrades should be considered.

Those objecting to SPP's proposal charged it would give facilitating TOs "unilateral power" and "unduly" benefit them and the zone's largest network load customer by allowing a single customer, based on the size of its load, to dictate planning criteria for everyone else in the zone.

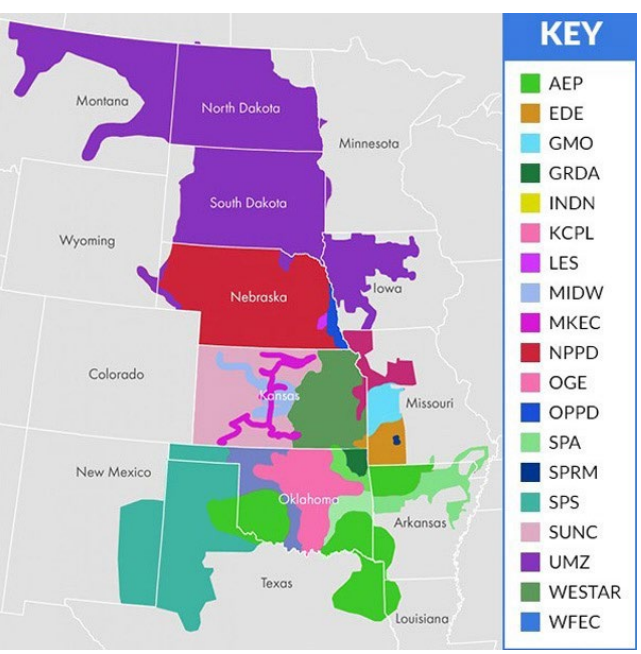
In a joint protest, GridLiance and Tri-County said "this puts every other entity within the zone at a disadvantage and unduly discriminates against smaller loads in the zone and non-facilitating" TOs. KPP and the cooperatives contended the facilitating TOs are not obligated to take stakeholder input into account when establishing the planning criteria.

The comments echoed their concerns over transparency and equality when the revision request was discussed and approved during SPP's April governance meetings. Four representatives on the 21-person Members Committee, which advises the Board of Directors with a show of hands, voted against the measure and a fifth abstained. (See "Directors Approve Zonal Planning Criteria, Z2 Elimination," *SPP Board/Members Committee Briefs: April 28, 2020*.) The Markets and Operations Policy Committee passed the proposal, with 73.44% approval. (See "Zonal Planning Criteria Meets Opposition," *SPP MOPC Briefs: April 14, 2020*.)

FERC agreed with the protests, finding that in zones with multiple TOs, SPP's proposal would give an undue preference to the network customer with the zone's largest total network load and to the facilitating TO.

In an email to *RTO Insider*, GridLiance High Plains President Brett Hooton said, "FERC's important ruling recognizes that the proposal would have given large incumbent transmission owners complete control over transmission upgrade criteria."

"Under SPP's proposal, the network customer with the largest total network load in the zone would have sole authority to designate a single transmission owner in the zone as the facilitating transmission owner, which could be the network customer itself (if it is also a transmission owner) or a transmission-owning affiliate," the commission said.



SPP's transmission pricing zones | *SPP*

Transmission lines in the WAPA footprint | *Southwire*

"This raises concerns that the facilitating transmission owner could potentially select zonal planning criteria that address its own local reliability needs ... or could potentially foreclose SPP's consideration of local reliability needs of other transmission owners in the zone when identifying the need for zonal reliability upgrades," FERC wrote. In that case, it noted, the resulting reliability upgrades' costs would be allocated to all customers in the zone.

The commission said SPP's proposal would be unduly discriminatory toward the zone's other transmission customers that do not serve the largest share of load and toward non-facilitating TOs. Aside from attending open meetings, FERC said the zone's other customers and TOs would have "no formal process rights" or the ability to influence the facilitating TO's decisions in establishing the planning criteria.

"Facilitating transmission owners could potentially prevent the local reliability needs of other transmission owners in the zone from being considered and thus prevent zonal reliability upgrades from being constructed in response to those needs," FERC said.

The Tariff proposal was one of 21 recommendations from the Holistic Integrated Tariff Team, which spent 15 months in an effort to help SPP adapt to the evolving grid and electricity markets. ■

Company Briefs

Ex-PG&E Employee Pleads Guilty to Kickback Scheme

Ronald S. Schoenfeld, a former Pacific Gas and Electric employee, pled guilty last week to one count of conspiracy to commit fraud for accepting kickbacks of more than $1.4 million in a scheme to divert business to his cousin's transportation company over the course of eight years. Schoenfeld is scheduled to be sentenced in November and faces a maximum penalty of five years in prison and a $250,000 fine.

PG&E paid at least $82.1 million to the transportation business operated by Schoenfeld's cousin during an eight-year period between March 2007 and February 2015. The company also paid Schoenfeld more than $1.47 million in kickbacks during that time, federal officials said.

PG&E condemned Schoenfeld's actions and said it has opened an investigation into why the fraud was not detected sooner.

More: *San Francisco Chronicle*

Blackjewel Employees Seek Settlement

Hundreds of former employees of bankrupt coal company Blackjewel could receive payments under a proposal filed last week. The agreement would settle claims that the company didn't give workers the required notice that they would be laid off before it filed for bankruptcy. The settlement, which won't be final until a judge approves it, is scheduled for a hearing Oct. 9.

The deal calls for Blackjewel to pay $17.3 million to compensate nearly 2,000 former employees.

More: *Lexington Herald Leader*

Google Signs PPA in Texas

Google last week said it signed a power purchase agreement with Candela Renewables for 140 MW of solar power from a proposed facility in Texas.

The move continues the company's renewable energy procurement effort that ramped up in September 2019 when it announced a planned 1.6-GW package of agreements that included 18 energy deals.

The Renewable Energy Buyers Alliance ranked Google second behind Facebook in its Deal Tracker of 2019's Top 10 Large Energy Buyers in the U.S. Google's total was 1.107 GW compared to Facebook's 1.546 GW.

More: *Environment + Energy Leader*

Harrell Joins Avangrid

Avangrid last week announced the appointment of Brian Harrell to the role of chief security officer and vice president of physical and cybersecurity. Harrell will lead the security efforts across the entire company.

Prior to joining Avangrid, Harrell served as assistant secretary for infrastructure protection at the Department of Homeland Security and as assistant director for infrastructure security at the U.S. Cybersecurity and Infrastructure Security Agency.

More: *Security Magazine*

IPL to Pay Millions in Fines over Clean Air Act Violations

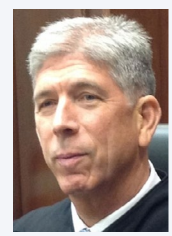
Indianapolis Power & Light (IPL) last week agreed to reduce emissions at its coal-fired power plant in Petersburg, Ind., after federal officials filed a lawsuit claiming the utility repeatedly violated the Clean Air Act.

As part of the agreement, IPL will pay a $1.5 million civil penalty split between the U.S. and Indiana, with the state receiving $600,000. The company also will spend $5 million at Petersburg to offset the "harm to the environment caused by the plant's excess emissions" over the years.

IPL received notices from EPA in September 2009, September 2015 and February 2016 alleging the utility had violated the CAA. According to the complaint, IPL replaced various components and pieces of equipment at the plant that enabled it to burn more coal. As a result, the utility "should have expected to and/or actually did" see a significant increase in its emissions of contaminants into the air.

More: *Indianapolis Star*

Murray Energy Bankruptcy Plan Approved



Judge **John E. Hoffman Jr**., of the U.S. Bankruptcy Court for the Southern District of Ohio, last week approved Murray Energy's Chapter 11 bankruptcy plan, despite a handful of objections from creditors and the U.S. Department of Justice.

The nation's largest private coal producer will continue operating under the ownership of a lender group that includes Bain Capital Credit, Eaton Vance Management and Silver Point Capital. The purchasers will forgive $1.2 billion in debt as part of the deal and use a $45 million loan from Silver to finance the bankruptcy exit.

Murray filed for bankruptcy in October with more than $2.7 billion of debt.

More: *Bloomberg Law*

Federal Briefs

Companies Form Clean Energy Lobbying Group with AWEA

NextEra Energy, Avangrid and Berkshire Hathaway Energy last week announced they have joined forces to form the American Clean Power Association. The group will merge with the American Wind Energy Association to create a new lobbying organization ahead of the November presidential election.

The group's priorities will include environmental policy, market reform and grid modernization.

The renewables industry spent less than $18 million on lobbying in 2019, compared to more than $104 million spent by oil, gas and coal, according to Bloomberg government data. This year, spending by clean energy firms is about one-fifth of that of the fossil-fuel industry.

More: *Bloomberg Green*

EPA Relaxes Rules Limiting Toxic Waste from Coal Plants

EPA last week relaxed Obama-era standards for how coal-fired power plants dispose of wastewater laced with pollutants like lead, selenium and arsenic by scaling back the types of treatment technologies utilities must install to protect rivers and other waterways. It also pushed back compliance dates and exempted some plants from taking any action at all.

The agency estimates the new rule will save the electric power industry about $140 million annually and eliminate 1 million additional pounds of toxic pollution each year.

EPA Administrator Andrew Wheeler described the revisions as "more affordable pollution control technologies" that would "reduce pollution and save jobs at the same time." Meanwhile, environmental activists say the new rule threatens the health of 1.1 million Americans who live within 3 miles of a coal plant.

More: *The New York Times*

FERC: Morenci Project Stays out of MTEP 18

FERC last week upheld its earlier ruling that said a small Michigan transmission project in MISO's 2018 Transmission Expansion Plan (MTEP 18) is a local distribution facility that cannot be included.

The commission refused Wolverine Power Supply Cooperative's request for rehearing to categorize Michigan Electric Transmission Co.'s (METC) $21 million, 138-kV Morenci line near the Michigan-Ohio border as transmission. (See *Morenci Project Dropped from MTEP 18*.) The co-op had argued that FERC used its seven-factor test when it shouldn't have and relied too much on the Michigan Public Service Commission's findings that the line was distribution in nature. It also said FERC was inappropriately influenced by the potential cost impact to Consumers Energy's customers if the line were classified as transmission. FERC said it was free to apply its seven-factor in this case, noting that it can use it beyond the context of its designed use for unbundled, retail-wheeling service.

More: *EL19-59*

Interior Watchdog Says Officials Misled Congress on BLM Relocation

A report last week from the Interior Department's Office of Inspector General found that two top department officials misled Congress when they claimed high office rent in D.C. was a factor in the need to move the Bureau of Land Management to a new headquarters in Colorado.

Joseph Balash, a former assistant secretary for land and minerals management, and acting Director William Perry Pendley are implicated in the report. Both men wrote in correspondence with Congress that BLM would be unable to stay in its existing office because the cost would exceed the $50/square foot limit set by the government. Instead, the report found the claims were "misleading" and "the future lease cost of 20 M Street was irrelevant."

"The evidence indicated that the future lease cost of 20 M Street was irrelevant at that point due to the department's earlier plans to move the BLM into the Main Interior Building or another federal facility," the inspector general said.

More: *The Hill*

State Briefs

ARIZONA

APS Asked to Forgive Unpaid Debt amid COVID-19, Hot Summer

Several community groups last week asked Arizona Public Service (APS) to forgive about $30 million in debt from customers who have not paid bills during the COVID-19 pandemic and this summer's record-breaking heat.

The local Sierra Club chapter; Our Voice, Our Vote; Living United for Change in Arizona; Mi Familia Vota; Arizona Interfaith Power and Light; and Chispa all signed a letter sent to APS asking for debt forgiveness. APS said it had not received the letter but has tried to help customers who are struggling financially.

APS customers have accumulated about $26.5 million in unpaid residential bills as of early August and are likely to continue increasing the balance into October.

More: *The Arizona Republic*

CALIFORNIA

Plan to Raise Utility Bills to Fight Wildfires Killed

A legislative plan to add about $1 to the monthly bills for customers of Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric failed to receive a vote in the State Senate last week. The money would have been used to finance a $3 billion fund to help reduce the risk of wildfires.

AB 1659 came up days before the end of the legislative session and was brought up as an emergency measure, which meant it required a two-thirds vote of the legislature to pass. The bill failed to get out of the Senate in its final voting session before adjournment, even after it had been stripped down to a $500 million fund.

More: *The Mercury News*

PUC Audit Finds High Rate of PG&E Line-sparked Fires

A recent Public Utilities Commission audit found that Pacific Gas and Electric's distribution lines spark two-and-a-half times more fires per mile compared to other utilities — a rate that poses a "serious risk."

The audit, done on behalf of the PUC's wildfire safety arm, found that the utility had nearly 50% more equipment-failure-sparked fires between 2015 and 2019 over other utilities, with half of those involving line failures. Furthermore, the audit said the high rate of line-sparked fires has "a significant impact" on safety.

PG&E said its plan to tackle both the causes of fires and factors contributing to fire spread by focusing on about 5,000 miles of line that pose the "highest risk."

More: *KNTV*

SMUD Picks New CEO, GM

The Sacramento Municipal Utility District (SMUD) last week chose Paul Lau to succeed Arlen

Orchard as its new CEO and general manager, effective Oct. 3.

Lau, a 38-year SMUD veteran, currently serves as chief grid strategy and operations officer. He has been a member of the company's executive team for more than 12 years.

"I'm honored and humbled to be chosen by the board of directors to lead this great organization and continue SMUD's reputation for community leadership and excellence," Lau said.

More: *SMUD*

COLORADO

PRPA Eyes 90% Noncarbon Electricity for Fort Collins

Platte River Power Authority last week said it is poised to adopt a plan to achieve more than 90% carbon-free electricity for Fort Collins and surrounding areas by 2030. It would mean the utility would fall short of its goal of 100% noncarbon electricity by the same time.

While the utility is finishing its 2020 integrated resource plan, its board of directors, who will make a final call on the IRP this month, discussed the plan at length at its meeting last week. Of the two options, staff recommended the "zero coal" option because their modeling predicts the "zero carbon" option would lead to larger rate increases and possible reliability issues. The zero-carbon portfolio projects a wholesale electricity rate increase of 130% between 2021 and 2030 (9% per year), while the zero-coal option projects a more gradual rate increase of about 52% between 2021 and 2040 (2% per year).

More: *Coloradoan*

ILLINOIS

Moratorium on Residential Disconnections Extended

The Commerce Commission last week said several of the state's regulated electric, natural gas, water and sewer utilities have again voluntarily agreed to extend the moratorium on disconnections for customers.

Ameren Illinois and Commonwealth Edison have agreed to extend through Sept. 10. Nicor Gas, Northshore/Peoples Gas, Illinois American Water, Aqua Illinois and Utility Services of Illinois agreed to extend the moratorium until Sept. 30.

More: *WIFR*

MAINE

CMP Starts Incentive Program for High-power EV Chargers

Central Maine Power (CMP) last week launched an incentive program for the installation of high-power electric vehicle charging stations to understand consumer funding preferences. The pilot program, which was approved by the Public Utilities Commission, seeks to determine what incentives are most valued by developers, fleet managers, municipal planners and others who decide to install more expensive but faster level 2 chargers.

CMP will offer up to $4,000 toward the cost of installing the charging stations. Efficiency Maine Trust is also taking part in a similar program and will offer rebates to applicants, who will then purchase and install their own infrastructure to connect to the charging pads.

The review process will begin Oct. 1.

More: *Portland Press Herald*

MARYLAND

PSC Extends Service Shutoff Moratorium 1 More Month

The Public Service Commission last week voted to extend the state's moratorium on utility service shutoffs through Oct. 1.

In addition to extending the moratorium, the measure adopted by the PSC also requires utilities to supply residential ratepayers with a 45-day notice that service will be terminated; requires utilities to offer a 12-month repayment plan for consumers who are in arrears; decrees that no down payment is required by consumers who enter into a repayment agreement with a utility; and that negotiations between a utility and a consumer over a repayment plan cannot be cut if the consumer has been in arrears in the past.

More: *Maryland Matters*

MONTANA

Senate Candidates Spar over Carbon-pricing Proposal

U.S. Senate candidates Gov. **Steve Bullock**

(D) and incumbent Steve Daines (R) last week sparred on social media over a carbon-pricing proposal from the Climate Solutions Council. The proposal suggested the state work with its congressional delegation and other organizations on a carbon cap or price to lower emissions and generate revenue to bolster the economy.

Daines has tweeted about the proposal a few times and said it "will kill Montana jobs and wreck our rural economies and communities." He also sent a letter to Bullock criticizing the proposal as "reckless." Bullock sent a letter back to Daines, saying, "Although it may be campaign season, your attack on me and my office also attacks the work of this council. I read it as a reprehensible display of politics, indicative of your limited capacity to tackle a challenging issue facing our state and our nation and, unfortunately, unsurprisingly consistent with your tenure."

More: *Bozeman Daily Chronicle*

NEW MEXICO

Environment Department Cites Gas Plants for Excess Air Pollution

The Environment Department last week announced compliance orders against plant operators DCP Operating Co. and Energy Transfer Partners with potential fines of more than $7 million for allegations of vastly exceeding permitted air pollution limits while burning off excess natural gas.

The department said that four facilities operated by DCP were cited for emitting more than 1.6 million pounds of pollutants between May 2017 and August 2018. ETP was cited for emitting approximately 3.1 million pounds of pollutants in excess of limits at one plant between January 2017 and August 2018.

More: *The Associated Press*

PENNSYLVANIA

Senate Committee Advances Bills to Limit RGGI

The Senate Environmental Resources and Energy Committee last week voted 8-3 on Senate Bill 950 and House Bill 2025. Either would authorize the General Assembly — with the Department of Environmental

Protection, the Environmental Quality Board, the Public Utility Commission — to determine whether and how to regulate or impose a tax on carbon dioxide emissions.

Sen. Joe Pittman, vice chairman of the committee, said the bills do not prohibit the state from entering the Regional Greenhouse Gas Initiative, but rather give "a voice to the voiceless" that would be impacted by a tax.

The state's timetable sets it for RGGI entry on Jan. 1, 2022.

More: *The Indiana Gazette*

SOUTH CAROLINA

Santee Cooper Finalizes VC Summer Settlement

The Santee Cooper board of directors last week finalized a settlement with Westinghouse Electric that will enable the state-owned utility to sell off leftover parts and materials from the failed V.C. Summer project. The settlement requires the two to split the profits from any remaining equipment that could be used on another site.

The companies will evenly split the profits on the most expensive components that are still being warehoused at the site, but Santee Cooper will get 90% of the profits on the other major components that were already welded, bolted or cemented into place. Proceeds from any remaining nuclear equipment will also be divided up, with Santee Cooper getting 67%.

More: *The Post and Courier*

VIRGINIA

Northam Wants Dominion to Forgive Overdue Bills

Gov. **Ralph Northam** wants Dominion Energy to cover unpaid residential electric bills with $320 million the State Corporation Commission said the company overcharged from 2017 to 2019.

Northam is pushing for new budget language requiring Dominion to return most of the $503 million the SCC recently said it had earned above authorized levels the last three years. The figure is based on preliminary calculations and could change during a formal review.

Under the plan, which must be approved by lawmakers, customers who have bills that are more than 60 days overdue as of Sept. 30 would have them forgiven. It would also set aside money to cover bills that are 90 days overdue whenever Northam lifts the moratorium on disconnections. Dominion did not comment.

More: *The Associated Press*

WISCONSIN

MGE Proposes Electricity Rate Freeze, Natural Gas Hike

Madison Gas and Electric (MGE) last week filed an application with the Public Service Commission that would raise natural gas prices by about 4.1% while holding electricity rates flat next year. If approved, the deal is expected to cost the average household about $27/year more for gas.

MGE is proposing to use 2019 fuel savings and put off collection of some expenses until 2022 to offset the need for an electric rate increase next year.

The Sierra Club said it plans to contest the proposal, saying the rate freeze will simply result in bigger hikes down the road.

More: *Wisconsin State Journal*