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FERC Changing ROE Rules; Higher Rates Likely for TOs

By Rich Heidorn Jr.

In a victory for transmission owners, FERC last week signaled a major change in how it sets TOs' return on equity rates, saying it will no longer rely solely on the discounted cash flow (DCF) model it has used since the 1980s.

Instead, the commission said it will give equal weight to results from the DCF and three other techniques: the capital asset pricing model (CAPM), expected earnings model and risk premium model.

The commission's new policy came in its long-awaited response to the D.C. Circuit Court of Appeals' April 2017 ruling vacating Opinion 531, FERC's 2014 order on the New England Transmission Owners' (NETOs) ROE rates. (See Court Rejects FERC ROE Order for New England.)

The Oct. 16 order proposes a methodology for addressing the issues remanded to the commission in *Emera Maine v. FERC* and pending in three other proceedings involving NETOs' ROEs, setting a paper hearing on how the methodology should apply.

"In relying on a broader range of record evidence to estimate NETOs' cost of equity, we ensure that our chosen ROE is based on substantial evidence and bring our methodology into closer alignment with how investors inform their investment decisions," the commission wrote (EL11-66-001, *et al.*).

Higher Hurdle for ROE Complaints

FERC said it would use the methodology to determine initially whether an existing ROE remains just and reasonable. It said it will use three of the models — the DCF, CAPM and

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FERC Reduces ITC Adders over Independence Issues
(p.19)

Chatterjee Dodges as DOE Spins on Coal Bailout

McIntyre's Future in Question

By Rich Heidorn Jr.

FERC Commissioner Neil Chatterjee | © *RTO Insider*

ARLINGTON, Va. — FERC Commissioner Neil Chatterjee and Assistant Energy Secretary Bruce Walker pledged to continue their work on grid resilience Wednesday following the apparent demise of the Trump administration's latest plan to prop up struggling coal and nuclear plants.

The two appeared at the Department of Energy's Electricity Advisory Committee meeting, where Walker charged the panel with

Continued on page 4

CAISO Symposium Looks to Grid's Future

By Hudson Sangree

SACRAMENTO, Calif. — Solar and wind will replace fossil fuels. Big batteries will store renewable energy. And every new vehicle sold will be electric.

The 1,000 or so attendees at *CAISO's Stakeholder Symposium* got a glimpse of what the future could hold from visionaries, venture capitalists and carmakers during the event's 10th anniversary at the Sacramento Convention Center.

"If we come back here in 2030 or 2040, we won't even recognize the grid," said Ron Dembo, a former Yale University professor and high-tech entrepreneur who kicked off the event as its keynote speaker.

Dembo's message was to prepare for the unpredictable. He gave the example of a forest fire so fierce that it could jump a major freeway

About 1,000 people packed the Sacramento Convention Center for the 10th annual CAISO Stakeholder Symposium on Oct. 17 and 18. | © *RTO Insider*

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Brad Jones (left) abruptly quit as CEO last week and will be replaced by General Counsel Robert Fernandez. | *NYSO*

Brad Jones out at NYISO

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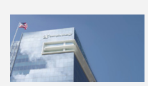

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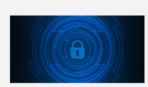

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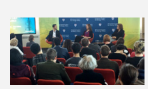

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FERC Changing ROE Rules; Higher Rates Likely for TOs

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expected earnings — to establish a composite zone of reasonableness, which will be "an evidentiary tool to identify a range of presumptively just and reasonable ROEs." (The risk premium model results in a single number and cannot produce a range of reasonable rates, the commission said.)

"Under this approach, we intend to dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile — unless that presumption is sufficiently rebutted," the commission said.

This new threshold, and FERC's indication that it will act more quickly on complaints, appears to address complaints by TOs and the Edison Electric Institute over "pancaked" ROE complaints being filed while prior cases remained pending. (See *EEI White Paper Calls for End to 'Pancaked' Rate Cases*.)

When the existing ROE has been shown to be unjust and unreasonable, the commission said, it will use all four models to produce four individual cost of equity estimates; the just and reasonable ROE will be the average of the results.

"For each of the DCF, CAPM and expected earnings models, we propose to use the central tendency of the respective zones of reasonableness as the cost of equity estimate for average risk utilities. We would then average those three midpoint/median figures with the sole numerical figure produced by the risk premium model to determine the ROE of average risk utilities. We would use the midpoint/medians of the resulting lower and upper halves of the zone of reasonableness to determine ROEs for below or above average risk utilities, respectively. Because our current policy is to cap a utility's total ROE, i.e., its base ROE plus incentive ROE adders, at the top of the zone of reasonableness, we propose to use the composite zone of reasonableness produced by the DCF, CAPM and expected earnings to establish the cap on a utility's total ROE."

Based on evidence from the first NETO complaint, the new approach resulted in a range of presumptively just and reasonable ROEs of 9.6 to 10.99%. Based on this analysis, the commission said the just and reasonable base ROE would be 10.41% and the cap on NETOs' total ROE, including incentives, would be 13.08%.

"However, these findings are merely preliminary," it added, saying the paper hearing would incorporate feedback on its proposed framework.

The commission's 2014 ruling — prompted by a 2011 complaint by New England state officials and others alleging that the NETOs' 11.14% base ROE was excessive — reduced the base ROE to 10.57%. (See *FERC Splits over ROE*.) But the D.C. Circuit said FERC failed to meet its burden of proof in declaring the existing 11.14% rate unjust and unreasonable.

'Administrative Burden'

Although FERC acknowledged that using multiple models increases the "administrative burden" in ROE cases, the commission said it decided to broaden its approach after concluding that the DCF methodology no longer captures how investors make decisions.

"We believe that, since we adopted the DCF methodology as our sole method for determining utility ROEs in the 1980s, investors have increasingly used a diverse set of data sources and models to inform their investment decisions. Investors appear to base their decisions on numerous data points and models, including the DCF, CAPM, risk premium and expected earnings methodologies."

The commission said the DCF methodology produced lower ROEs than the three other models for the four test periods at issue in the NETO proceeding. It noted that the models' results sometimes "move in opposite directions."

Models Explained

The commission's order includes an appendix explaining the four approaches. The two-step DCF methodology incorporates both short-term and long-term growth projections. CAPM is used by investors to measure the cost of equity relative to risk.

The risk premium methodology considers interest rates as a direct input to compare returns on stock investments to that on less risky bonds.

The expected earnings analysis is based on the book value of individual stocks and can be either backward-looking using historical earnings, or forward-looking using analysts' earnings forecasts.

Analyst: Higher Rates Likely

ClearView Energy Partners analyst Christine Tezak said the commission's new approach will likely result in higher top values to the zone of reasonableness than seen since Opinion 531's adoption. "This potential re-expansion of the zone of reasonableness would make it more likely that transmission owners will realize higher base ROEs than the DCF model alone indicated without a subsequent subjective upward adjustment. A broader range of reasonableness returns also looks likely to restore the full value of incentive adders awarded to transmission owners in prior proceedings."

Information on how FERC may apply the new methodology to other TOs may come at Thursday's open commission meeting, the agenda for which includes the NETO docket.

"We will be looking for an indication at the open meeting as to whether the industry should begin integrating these new principles into pending, recently filed and upcoming rate cases and pending complaints now, or wait" for the conclusion of the paper hearing, Tezak wrote.

The commission set a 60-day deadline for filing

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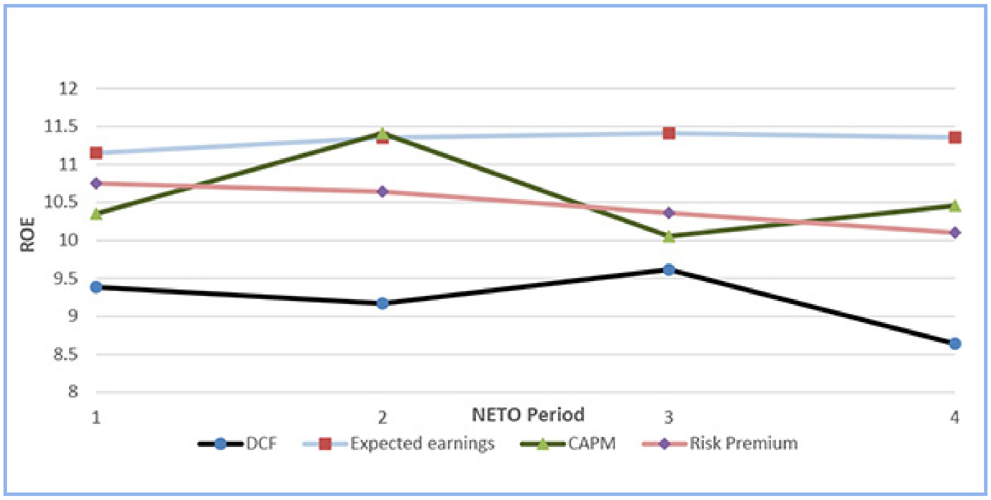


FERC said the discounted cash flow methodology produced lower ROEs than the three other models for the four test periods at issue in the New England Transmission Owners' proceeding. | *FERC*

Chatterjee Dodges as DOE Spins on Coal Bailout

McIntyre's Future in Question on Eve of FERC Meeting

Continued from page 1

reconsidering current practices on spinning reserves, calling it wasteful to have 15% of capacity "doing no work."

Walker also did a little spinning of his own, insisting that DOE's "leaked pre-decisional memo" calling for price supports for "fuel secure" generation was never about propping up nuclear plants or the coal industry. The memo became public at the beginning of June, after Trump — who had made saving the coal industry a signature campaign promise — directed Energy Secretary Rick Perry to "prepare immediate steps to stop the loss" of fuel-secure generators facing retirement. (See *Trump Orders Coal, Nuke Bailout, Citing National Security*.)

"It was not focused on coal or nuclear," Walker said. "It was a recognition that there has been a significant change in the portfolio of generation throughout the United States ... most notably a significant reliance on natural gas pipelines for electric generation."

Talking to reporters after his speech, Walker elaborated. "The fact is, the words in the pre-decisional memo were 'all fuel secure generation.' Everybody misinterpreted the words for whatever political reasons they chose to," he said. "There's liquid natural gas that can have on-site fuel. There's biomass conversion that has on-[site] fuel. ... Pump storage, that's fuel-secure generation. Hydro, that's fuel-secure generation."

Chatterjee in a Rush

The normally gregarious Chatterjee rushed with aides to an awaiting SUV immediately after his remarks from the podium, declining to take questions from the committee and refusing to talk with reporters.

Asked how the apparent failure of the Trump/Perry plan would affect FERC's work, Chatterjee said, "We've got our resilience docket open.

"We'll continue to work on it," he said, getting into the car. FERC opened the resilience docket in January after rejecting DOE's earlier bid to help coal and nuclear plants. (See *FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry*.)

Was the demise of the DOE plan disappointing to him? "I didn't even know what they were considering," Chatterjee said.

McIntyre's Future

Chatterjee's haste may have had less to do with the coal and nuclear plan than with rumors that FERC Chairman Kevin McIntyre, who has been battling a brain tumor, may announce his resignation. Chatterjee — who had reportedly visited the White House on Oct. 16 — declined to respond to reporters' questions about McIntyre's status and whether he would resume as acting chairman.

Assistant Energy Secretary Bruce Walker | © *RTO Insider*

McIntyre did not attend the commission's open meeting Thursday, the second he has missed since a fall that left him visibly uncomfortable at the meeting in July. (See *Ailing McIntyre Absent from FERC Open Meeting*.)

Chatterjee noted McIntyre's absence as he opened Thursday's meeting, saying "My prayers are with him and his family."

"I'm very sorry Chairman McIntyre is not able to be here today, and I continue to send warm wishes to him for his recovery," Commissioner Cheryl LaFleur said.

In March, McIntyre issued a statement saying he had undergone "successful surgery" for a "relatively small" brain tumor that was discovered in summer 2017. He said he did not intend to provide further details or updates for privacy reasons.

At the July meeting, he wore a sling after disclosing he had injured his arm and suffered compression fractures in two of his vertebrae in a fall. (See "McIntyre Toughs it out," *FERC Says Farewell to Powelson*.)

Although he was not present for the September meeting, McIntyre participated in its votes; he was not recorded as voting on Thursday.

Sources have told RTO Insider that the chairman is often absent from FERC headquarters and that meetings with him have been frequently rescheduled as a result. Spokeswoman Mary O'Driscoll last month declined to answer questions on the subject.

Chief of Staff Anthony Pugliese told reporters after Thursday's meeting that the chairman would issue a statement on his status within a few days.

With the resignation of Republican Commissioner Robert Powelson in August, the commission is now split 2-2 between Republicans and Democrats. Earlier this month, President Trump nominated the Department of Energy's Bernard McNamee as Powelson's replacement. (See *Trump Nominates DOE's McNamee to FERC*.)

Perry: Out of Our Hands

DOE's Walker, who heads the Office of Electricity, did not explicitly confirm the numerous news reports that the White House had rejected DOE's proposal following opposition from the National Security Council and National Economic Council. Perry told reporters in September that DOE had finished its resilience proposal and was awaiting a White House decision.

The memo outlined "one of the many possible solutions," Walker said. "We are focused on national security. We will continue to look at what are the things that best support the infrastructure that's needed under national security." ■

Overheard at Storage East 2018

WASHINGTON — Infocast's inaugural Storage East summit drew policymakers, grid operators, utilities and companies looking to break into energy storage to the Washington Plaza Hotel last week. Panelists discussed the optimism surrounding the industry, as well as strategies for locating resources and optimizing their services for maximizing returns.

Here's some of what we heard.

Infocast's inaugural Storage East summit was held at the Washington Plaza Hotel in D.C. on Oct. 16-17, 2018. | © *RTO Insider*

Chatterjee Touts FERC Orders

FERC Commissioner Neil Chatterjee delivers the keynote address of the conference. | © *RTO Insider*

FERC Commissioner Neil Chatterjee kicked things off by recalling actions the commission has taken on storage since he joined in August 2017. The highlight of these was the February issuance of Order 841, which directed RTOs and ISOs to revise their tariffs to allow energy storage resources full access to their markets. (See ***FERC Rules to Boost Storage Role in Markets***.)

When Chatterjee joined FERC as chairman, he restored the commission's quorum, which it had been without for six months. He said he had expected to be able to vote on a final version of the commission's November 2016 Notice of Proposed Rulemaking as soon as he walked in, but he found that staff were still working on "a number of complex, legal and technical issues."

"Understanding the importance of what was at stake, during my tenure as chairman, I worked closely with staff to push that final rule forward," he said proudly. "I believe in the potential for storage to be a transformative technology for our grid. Storage is a game-changer. I'll admit it's a bit cliche, but there's truth to it."

He also noted the importance of Order 845, which revised the commission's pro forma large generator interconnection procedures and interconnection agreement. One of the 11 changes the commission approved was to include storage in the definition of "generating facility." (See ***FERC Order Seeks to Reduce Time, Uncertainty on Interconnections***.)

Another change allows generators to sell their surplus interconnection capacity to other resources. Storage owners can purchase surplus capacity for their resources so they can interconnect without having to go through the full queue, Chatterjee said.

"While this change in policy sounds very wonky — and it is — I think it's a subtle but important action we've taken to improve opportunities for storage development."

Chatterjee also noted the challenges storage still faces. RTOs and ISOs face a Dec. 3 deadline for their Order 841 compliance filings. FERC is "likely to take several months" to review them, and any deficiencies it finds will delay implementation further, Chatterjee said.

He also said grid operators have been slow to develop new products to compensate storage resources for their different services.

"With the exception of PJM's RegD product, there's been little momentum toward expanding the traditional set of ancillary services in the past few years," Chatterjee said. "The increasing penetration of renewables might provide additional momentum for such products, but in any event, whether and how these products come to fruition could have a significant effect on the opportunities for storage."

Siting and Co-location

Multiple panelists discussed the best strategies for deciding where to develop storage resources.

Michael Harrington, Utility of the Future department manager for Consolidated Edison | © *RTO Insider*

Storage can receive the federal investment tax credit when added to existing qualifying resources, mainly solar facilities. But Michael Harrington, of Consolidated Edison's Utility of the Future department, pointed out that the New York State Energy Storage Roadmap, issued in June, predicted that more than half of the 1,500 MW of storage the state aims to procure by 2025 would be downstate, close to New York City's load.

"We do think there's opportunity with upstate renewables, but certainly we recognize that storage is going to follow where the economics are the best," he said.

Ascend Analytics CEO Gary Dorris | © *RTO Insider*

Ascend Analytics CEO Gary Dorris explained why being near the city is so attractive for storage. The best way to determine where to site storage resources, he said, is finding where prices are most volatile: where congestion on the grid is most persistent.

Price spikes occur very infrequently on a typical New York node — only 1.5% of a 24-hour day — but they represent 22% of the average real-time energy price, according to Dorris. "So storage can be a wonderful physical hedge against price spikes, and that's a real opportunity to mitigate uncertainty in supply by having that physical hedge in attacking those price spikes."

"Co-located storage with renewables certainly has benefits, but is co-locating renewables with storage going to become standard practice?" Chatterjee posited. "The answer to that question could have major implications for storage. We have evidence that the cost-benefit ratio of co-located storage is tipping in favor of adding storage."

He pointed to a 2017 resource solicitation by Xcel Energy's Public Service Company of Colorado. While individual wind and solar resources received median offers of $18/MWh and $29 MWh, respectively ("amazing numbers in their own right"), wind and solar resources co-located with storage received a $3 and $7 premium.

"When you consider market incentives like ... capacity constructs in PJM and ISO-NE, co-location could be extremely beneficial in allowing renewables to avoid performance penalties and take advantage of high prices," he said.

Wish List from States, RTOs

Several speakers said grid operators and states could be doing more to value storage's services.

In introducing a panel on innovative business models for storage, Dorris suggested that states should lower their property taxes for storage. Taxes are particularly high in the Northeast, where storage is most in demand. "That's probably not being talked about as much as perhaps it could be given the nature of these projects," he said.

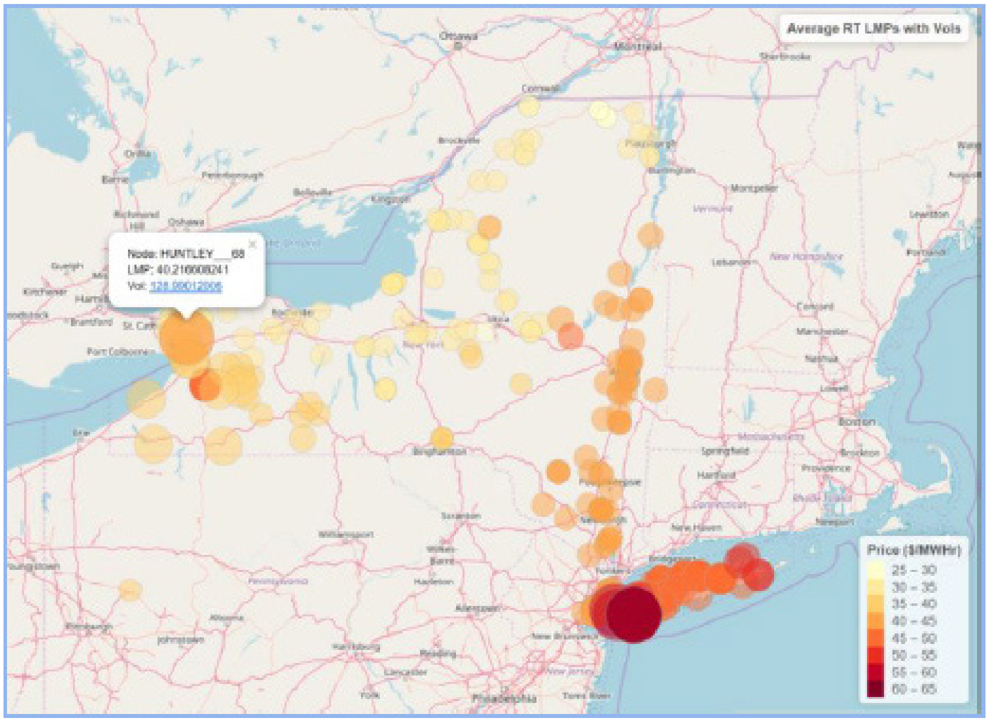
The panelists focused on the lack of a "T&D benefit" in RTOs and ISOs, saying storage should be compensated for its congestion-reducing benefits as energy efficiency programs are. Such programs are valued in part for reducing the voltage levels on transmission and distribution lines, allowing transmission owners and utilities to defer costly upgrades.

"Just level the playing field between how you treat conservation and how you treat storage," Dorris urged.

"As a developer, we need to have certainty, and we need to have predictability going forward," said Thomas Leyden of EDF Renewables. "That's not easy in a market-based system, but there are things that can be done to help our investors become more comfortable."

Adam Rousselle, CEO of Renewable Energy Aggregators, went further. He noted that transmission owners get paid fixed rates of returns based on the value of their assets. "If we can not align the development of storage with the transmission owner, we won't be building storage any time soon in PJM," he said. "And if your solution delays their transmission investment, they're competing with you, make no mistake about it." ■

— Michael Brooks



Prices in New York state are highest near the New York City metro area, where there is persistent transmission congestion. This presents the best economic opportunity for storage resources. | *Ascend Analytics*

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initial briefs (Dec. 17), with reply briefs due 30 days after that (Jan. 17, 2019).

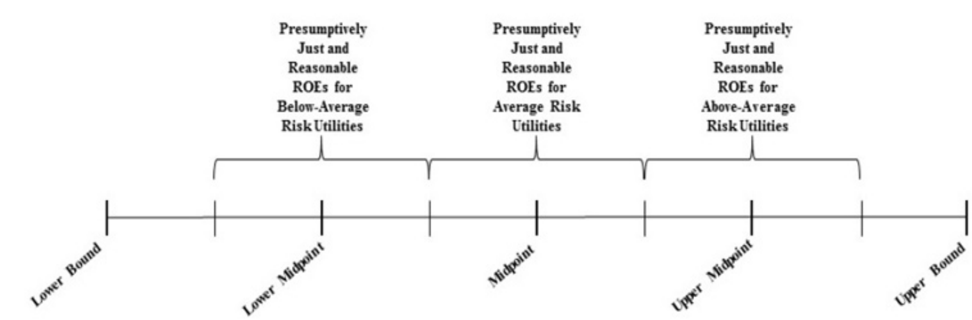
The New England TOs are Emera Maine (formerly Bangor Hydro Electric); Avangrid's Central Maine Power; National Grid; New Hampshire Transmission; The United Illuminating Co.; Unitil Energy Systems; Fitchburg Gas and Electric Light; Vermont Transco; and Eversource Energy (formerly Northeast Utilities, Connecticut Light and Power, NSTAR Electric, Western Massachusetts Electric Co. and Public Service Company of New Hampshire).

Commissioner Richard Glick, who formerly worked at Avangrid, did not take part in the ruling.

Commissioner Neil Chatterjee on Wednesday acknowledged concerns that uncertainty over how FERC would respond to the D.C. Circuit's remand had chilled transmission investments. "So, our action should help ensure [there is] more clarity going forward," he said during remarks at the Department of Energy's Electricity Advisory Committee meeting.

At the commission's open meeting Thursday, Chatterjee said "the commission will need to make important decisions about how the policy we've proposed in Emera Maine applies" in other ROE dockets.

Commissioner Cheryl LaFleur, who was chair when the commission issued Order 531, said that ruling was a compromise that set a tighter zone of reasonableness, with the ROE higher within the zone. "Here we're allowing a much wider band and the ROE is in the middle of the band." ■



Zone of reasonableness quartiles | *FERC*

CAISO/WECC NEWS

Fire Season Becomes Blackout Time in California

By Hudson Sangree

| National Weather Service

All three of California's big investor-owned utilities last week shut down power proactively or warned customers they might need to because of dry, windy conditions that could lead to wildfires, prompting one consumer group to call for a probe into the practice.

It was the first time Pacific Gas and Electric has cut off power to consumers in Northern California based on fire hazards. Southern California Edison and San Diego Gas & Electric have taken such steps before when the hot Santa Ana winds picked up, as happened last Monday and Tuesday.

With large fires becoming more the norm, and the state asking utilities to de-energize lines during severe weather conditions, California's summer and fall fire season is becoming a time of rolling blackouts in fire-prone areas.

Some ratepayer advocates, however, criticized the utilities this week for jumping the gun. They said the power outages may have been more about avoiding fire liability and sending a political message than about protecting residents.

"We clearly think it's blackout blackmail," said Jamie Court, president of Consumer Watchdog, an advocacy group based in Los Angeles.

The IOUs and Gov. Jerry Brown had urged state lawmakers this year to do away with California's unique system of holding utilities strictly liable for wildfire damage to private property. But the bill Brown signed in September, *SB 901*, left that liability standard, often called inverse condemnation, unchanged.

The new law requires utilities to file wildfire mitigation plans with the state that include procedures for shutting down power in extreme weather to prevent fires. (See *California Wildfire Bill Goes to Governor*.)

"They didn't get inverse condemnation [changed]," Court said. "They want to get out of liability forever for everything, and this is the way they send a signal. The biggest power a utility has is the ability to turn off power."

'Last Resort'

PG&E spokeswoman Angela Lombardi said the *decision to cut off power* to roughly 60,000 consumers last week was solely about wildfire prevention.

"Power safety shutoff will only be done as a last resort," Lombardi told RTO Insider. "It's only in the interest of public safety."

The company took the unprecedented step Oct. 14 and 15 of shutting off power to about 60,000 customers and notifying 37,000 others they could lose power because of gusting winds and bone-dry vegetation in the northern San Francisco Bay Area and the Sierra Nevada foothills near Sacramento. (See *PG&E Shuts down Power to Prevent Fires*.)

State fire authorities have blamed PG&E's equipment for sparking numerous fires in Northern California during the 2017 fire season, one of the most destructive in the state's history. The utility is facing billions of dollars in damages for those blazes, which occurred during times of high winds and low humidity.

In Southern California, *San Diego Gas & Electric* notified 4,700 customers Oct. 14 their power could be shut off "with the onset of Santa Ana winds and extremely low vegetation moisture forecasted for the next two days." The company ended up cutting power to 360 customers living in the foothills near the Cleveland National Forest and had restored power to most as of Oct. 16, but a red-flag warning remained in effect.

SDG&E, widely considered a state leader in wildfire prevention, has de-energized lines a number of times in the past because of hazardous fire conditions.

SCE issued warnings this weekend that it might have to shut down power as hot, dry Santa Ana winds began blowing from the desert to the ocean. The winds are typically a harbinger of Southern California's wildfire season, which tends to peak in the fall but has become more of a year-round problem in recent years with drought and climate change.

CPUC Monitoring

Consumer Watchdog's Court said the conditions were not sufficient to cut off power, especially to the elderly and infirm, including those who rely on oxygen machines, and to schools.

"If there are no fires or firefighters in an area, there is no reason for a utility to shut down power unless they know they have faulty equipment or problems with vegetation management," he said.

Consumer Watchdog sent a *letter* to California Public Utilities Commission President Michael Picker on Oct. 16 urging him to launch an investigation of PG&E's power shutdown and to "investigate each and every time a utility turns out the lights due to high winds."

In an email, CPUC spokeswoman Terrie Prosper said the commission had been monitoring this week's power shutdowns and warnings.

"We will do a post-event review, including the factors that went into PG&E's decision to de-energize, customer outreach, and notification and restoration times."

In general, Prosper added, "the state's investor-owned utilities have general authority to shut off electric power to protect public safety under California law, specifically California Public Utilities Code Sections 451 and 399.2a."

"The utilities have recently developed *programs* to exercise this authority during severe wildfire threat conditions as a preventative measure of last resort," she said. ■

CAISO Symposium Looks to Grid's Future

Continued from page 1

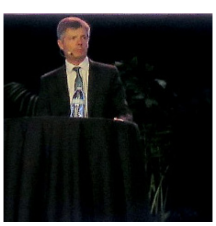
and burn down an urban neighborhood. That happened last year in Santa Rosa, Calif., but many experts would have called it highly unlikely before it occurred, he said.

"We're moving into a more volatile world, and that requires a different way of looking at things," he said.

Ron Dembo, Zerofootprint, and Mark Rothleder, CAISO | © *RTO Insider*

Dembo and Mark Rothleder, CAISO's vice president of market quality and renewable integration, said factors such as global temperatures, renewable energy and regional collaboration would guide the future grid. (See *Can Calif. Go All Green Without a Western RTO?*)

Other speakers warned about the dangers of climate change but laid out options that could limit global warming in the decades ahead.



Brian Davis, Shell | © *RTO Insider*

Brian Davis, vice president of energy solutions at Shell's New Energies business, explained the company's *Sky Scenario*, a roadmap for meeting the goals of the international Paris Agreement and keeping global warming to under 2 degrees Celsius, primarily through the "deep electrification" of energy systems.

The company's plan envisions moving to all-electric light transportation, a vast reduction in energy derived from oil and an equivalent increase in solar and wind production, and an end to deforestation and reforesting an area the size of Brazil.

Though extremely challenging, "it's technically, economically and industrially possible to do it," Davis, the conference's final speaker, told the audience.

Between Dembo's and Davis' big-picture perspectives, *panelists* got down to the nuts and bolts of shaping tomorrow's grid today.

Electrifying Transportation

Dan Richard, High-Speed Rail Authority | © *RTO Insider*

Dan Richard, chairman of California's High-Speed Rail Authority, said the controversial multibillion-dollar project should be a way that the state's 40 million residents, regardless of income, can travel up and down the state at 200 mph.

"So all Californians can benefit from this," Richard said as part of a three-person panel on the electrification of the transportation sector and the future of mobility. "We don't want this to be the Lexus train."

The high-speed rail project has begun construction near Fresno, one of the state's more affordable urban areas, and could put residents of that Central California city within commuting distance of jobs in Los Angeles, Richard and others said.

The rail line is one of outgoing Gov. Jerry Brown's big infrastructure projects and has been criticized as an expensive boondoggle by many residents and elected officials. Richard said it's a problem of imagination.

"People can't imagine having high-speed rail" and what it will mean for them, he said.

One critic from Fresno acknowledged to Richard that it could mean that she and her husband could go to San Francisco for dinner and a show and be home by bedtime, he said.

China has built 8,000 miles of high-speed rail lines in only 15 years, and anyone who's seen it quickly comprehends the benefits, he said.

Janea Scott, one of the five members of the California Energy Commission, moderated the transportation panel. She pointed out the problem of making electric transportation available to lower-income residents, for whom electric cars remain unaffordable and impractical.

Adam Langton, an electric vehicle expert with BMW of North America, said installing charging stations in lower-income neighborhoods would help, but that electric buses and trains should also be part of the solution.

"Think about electric miles," he said.

Creating Utility-scale Storage

A separate panel, moderated by CAISO Director of Regional Integration Phil Pettingill, talk-

Transit panel left to right: Dan Richard, High-Speed Rail Authority; Adam Langton, BMW; Janea Scott, California Energy Commission | © *RTO Insider*

CAISO/WECC News

Storage panel left to right: Phil Pettingill, CAISO; Yayoi Sekine, Bloomberg; Yet-Ming Chiang, MIT | © *RTO Insider*

ed about EVs in the context of stored energy.

In 2018, demand for lithium-ion batteries for vehicles exceeded the demand for batteries for consumer electronics, said Yayoi Sekine, who leads the Americas coverage for Bloomberg's energy storage practice. The demand for EV batteries has shot up rapidly and will increase to 1,500 GW of storage by 2030, she said.

A major problem now is how to store enough renewable energy to charge those car batteries and supply other energy needs after the sun sets. Solar generation is becoming less expensive and more abundant, especially in California, but it ramps up when it's often least needed in the daytime and must be stored to meet peak evening and early-morning demand.

"Once you have enough batteries, you're soaking up the solar," Sekine said.

Sekine and her fellow panelist Yet-Ming Chiang, a professor at the Massachusetts Institute of Technology, said they believed bigger and less costly lithium-ion batteries were the best bet for large-scale storage going forward.

"The technology that works today and is dropping in cost is lithium-ion," Chiang said.

However, he said scientists should look to cheaper and far more plentiful chemical components such as sulfur and saline for batteries. Future energy storage could end up looking more like chemical factories, with building-size vats connected by pipes and wire, than blocky batteries, he said.

"I think we're on the cusp of significant growth in grid-scale storage."

Investing for the Future

Carbon reduction is bound to be another growth area, said Nancy Pfund, founder and managing partner of DBL Partners, a venture capital firm that invests in social, economic and environmental change.

Pfund's advice to investors was to "follow the carbon." The past century was optimized for carbon, she said. "The next century will be optimized for carbon reduction and avoidance," she said.

Fighting climate change will mean monetizing carbon reduction for private industry rather than relying on environmental groups and governments. In addition to transportation, agriculture is a major sector that produces atmospheric carbon and is ripe for technologies to reduce its greenhouse gas emissions, she said.

Pfund was joined on the symposium's investment panel by Jill Anderson, vice president of customer programs and services with Southern California Edison, and Jackie Biskupski, mayor of Salt Lake City. The panel was moderated by Dede Hapner, formerly Pacific Gas and Electric's vice president of FERC and ISO relations.

CAISO Chairman David Olsen said California's ambitious goal of getting all of its energy from renewable and other zero-carbon sources by 2045 would require "electrifying just about everything." And Valerie Fong, chair of the ISO's Western Energy Imbalance Market, said, "Our industry is changing at an unprecedented rate."

Investment panel left to right: Dede Hapner, PG&E; Nancy Pfund, DBL Partners; Jill Anderson, Southern California Edison; Jackie Biskupski, Mayor of Salt Lake City | © *RTO Insider*

Wrapping up the conference, Shell's Davis said it's a remarkably dynamic time to be part of the electricity sector, as evidenced by the symposium's discussion topics.

"Who would have thought 20 or 30 years ago the energy industry was an exciting place to work?" Davis said. ■

ERCOT News

ERCOT Briefs: Week of Oct. 15, 2018

October TAC Meeting Canceled

The ERCOT Technical Advisory Committee canceled its Oct. 24 meeting, citing a lack of items to be considered this month. It's the fourth TAC meeting to be canceled this year, and the third in five months.

The TAC is scheduled to meet next on Nov. 29.

2019 Membership Applications due Nov. 9

ERCOT has distributed its membership *applications and agreements* for 2019, recommending that entities interested in joining the grid operator do so well in advance of Nov. 9 to avoid potential processing delays.

Applicants may join as corporate, associate or adjunct members. Corporate membership includes the right to vote on general membership matters, such as election of certain board members, election of TAC representatives and members of TAC subcommittees, and amendments to the Certificate of Formation and bylaws.

A TAC meeting goes off as scheduled. | © *RTO Insider*

Market participants are not required to be members.

Membership terms are for no more than a year and do not renew automatically. Dues are required at the time of application; applicants can request waivers for good cause.

Confirmation of board members and TAC representatives for 2019 will take place at the annual membership meeting Dec. 11.

More information and copies of ERCOT's bylaws and Articles of Incorporation can be found on the grid operator's *website*. ■

— Tom Kleckner

Sempra, Oncor Deals Target Texas Transmission

By Rory D. Sweeney

Sempra Energy's transmission footprint in Texas is set to expand with the *announcement* Thursday that its Oncor utility subsidiary is acquiring transmission owner InfraREIT, while Sempra will buy a 50% stake in Sharyland Utilities.

Sempra Energy's headquarters | *Sempra Energy*

Sempra CEO Jeffrey Martin said the combined $1.37 billion *deals* are "rotating capital away from noncore assets to core assets" in the company's ongoing shift away from generation resources and commodities into the guaranteed rates of return of regulated infrastructure.

InfraREIT and Sharyland are both owned by Hunt Consolidated, which made a play for Oncor in 2016 but scrapped the deal after the Texas Public Utility Commission attached conditions considered unacceptable by the creditors of Oncor parent Energy Future Holdings. (See *Texas PUC Denies Rehearing on Oncor Sale, Ends Hunt Bid*.) Sempra acquired EFH's 80% interest in Oncor earlier this year in an all-cash buyout valued at $9.45 billion. (See *Texas PUC OKs Sempra-Oncor Deal, LP&L Transfer*.)

Martin called Oncor the "logical" owner of InfraREIT's assets because of their "significant overlap" with the utility's existing service territory. Sempra CFO Trevor Mihalik noted that approximately 260 miles of InfraREIT's lines were previously owned by Oncor, but they were exchanged for Sharyland's distribution system as part of a 2017 rate case settlement. (See *Texas PUC OKs Settlement in Oncor-Sharyland Asset Swap*.)

The companies plan to submit the transactions as a single integrated filing over the next few weeks for approval by the Texas PUC, company officials said during an analyst call Thursday. It will also require review and approval by FERC and other federal agencies, they said.

The deals are expected to receive final approvals and close in mid-2019.

ERCOT News

Hunt will be the noneconomic general partner of Sharyland and continue to manage daily operations and appoint executive management.

Sempra said no equity will be issued to cover the price tag of the transactions. Sempra will fund its $1.12 billion share — which includes the $98 million to become a limited partner in Sharyland — with the proceeds from its recently announced $1.54 billion agreement to sell the majority of its renewable portfolio to Consolidated Edison.

The remainder of Oncor's payment for InfraREIT will be funded through a capital contribution from Texas Transmission Investment, which owns the remaining 19.75% of Oncor. The deal includes InfraREIT's outstanding debt of approximately $945 million and allows the company to solicit superior bids.

The deal also includes an "asset exchange" between InfraREIT and Sharyland that will result in all of InfraREIT's assets being located in North, Central and West Texas and all of Sharyland's being located in the southern part of the state. InfraREIT will receive two South Plains and Lubbock Power and Light interconnections, along with a Golden Spread Electric Cooperative transmission line that connects with its existing Competitive Renewable Energy Zone assets. Sharyland will receive a DC tie and assets in the city of McAllen that connect with its existing Cross Valley transmission line.

The swap will be a "like-kind exchange with no impact on taxes," Mihalik said.

Infrastructure over Commodities

The deal continues Sempra's bid to move away from the volatility of commodities in favor of the infrastructure that transports them, along with the stable returns those assets provide.

Oncor CEO Alan Nye explained the company's focus in Texas by highlighting the state's position as the second-largest economy among U.S. states and expectations that ERCOT's load will increase 16% within 10 years. "Significant" transmission expansion will be necessary to interconnect the roughly 40 GW of wind capacity and 30 GW of solar currently in ERCOT's interconnection queue, he said, along with oil and gas development in the Permian region of West Texas.

"The purchase of InfraREIT gives us access to high-quality transmission assets that are adjacent to our service territory and are a great fit for our portfolio," Nye said. "InfraREIT's existing presence in the panhandle and Permian places it in a unique position to benefit from these trends. ... The larger the footprint we have in Texas, the more exposure we have to potential transmission investment opportunities."

Sempra last month *announced* it was selling its interest in 980 MW of resources — 11 solar assets across the Southwest, and solar and battery storage development projects and one wind facility in Nebraska — to Consolidated Edison. The company's remaining seven wind facilities of roughly 720 MW, additional wind development projects and approximately 40 Bcf of natural gas storage in the Gulf Coast region remain up for sale. ■

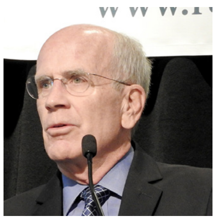
ISO-NE News

Climate Change Top of Mind at Vermont Conference

By Michael Kuser

Renewable Energy Vermont held its 2018 Conference and Expo in Burlington on Oct. 18-19. | © *RTO Insider*

BURLINGTON, Vt. — Climate change mingled with politics at last week's Renewable Energy Vermont Conference and Expo, where state regulators and officials expressed frustration with federal and RTO policies.



Peter Welch | © *RTO Insider*

While U.S. Rep. Peter Welch (D-Vt.) predicted a Democratic majority in the House of Representatives after the mid-term elections, some participants said planetary survival should come before party interests. Others focused on how to deliver cleaner electricity to consumers in New England.

Olivia Campbell Andersen | © *RTO Insider*

"It's time to pick up the pace," said Olivia Campbell Andersen, executive director of Renewable Energy Vermont. "Every week brings fresh evidence of the urgency of climate change. Close to home, here in Vermont, not a month goes by where our electric utilities aren't issuing warnings about the impending extreme weather and power outages."

Gordon van Welie | © *RTO Insider*

With hydropower in Quebec, wind energy in northern New England and offshore wind all relatively far from load centers, transmission infrastructure must be built to move the electricity from producers to consumers, ISO-NE CEO Gordon van Welie said.

"If you love renewable energy, you have to love transmission," van Welie said.

"The pipeline system built in the 1970s can't meet the needs of today's increased use of natural gas," he said. "For a while I thought the answer was simply to put in more gas infrastructure — an engineer's approach — but now we look to create a market solution. We propose to change the rules to maintain an energy buffer stock."

The RTO's thinking on the subject can be found in a recent ***report***, "Winter Energy Security Improvements: Market-Based Approaches," prepared for the Oct. 10 meeting of its Markets Committee.

"We want to use market-based incentives not only to supply the energy, but to reduce demand when needed and maintain a buffer stock of energy throughout the winter," van Welie said. "We have no details yet; we're in the process of designing this, and I'm bringing this to your attention so that if you're interested, you can engage in the appropriate forum, which is the [New England Power Pool] stakeholder committees."

The main idea is to move from the day-ahead market to a rolling, seven-day-ahead market, he said.

"We want to value energy that's available today, that can be used today, but also seven days from now," van Welie said. "And we want to purchase these commitments well ahead of the winter season so that we can stimulate investment in the right fuel arrangements, and ultimately the technologies that can actually deliver this type of service."

Mission Disconnect

Margaret Cheney | © *RTO Insider*

Abigail Anthony | © *RTO Insider*

Vermont Public Utility Commissioner Margaret Cheney said ISO-NE is "inevitably a partner because our missions overlap somewhat," but there's been "a disconnect in getting the RTO to recognize our in-state distributed generation in their long-range planning forecasts."

Rhode Island Public Utilities Commissioner Abigail Anthony said the RTO wants states in the region "to understand that their priority is reliability. I want ISO New England to understand that climate change is our state's priority and to take that seriously."

Lorraine Akiba | © *RTO Insider*

Lorraine Akiba, former Hawaii Public Utilities Commissioner, recounted sitting through the ISO-NE presentation and seeing "the lack of any planning for including more distributed energy resources into the ISO capacity portfolio, while others — California ISO in particular

ISO-NE News

is a good example … they're already into the market with energy storage and distributed generation from the utilities in that footprint, so it's doable. You just have to conceptualize it. I think PJM has already started that as well."

It's also important to address Rhode Island's concern about reliability versus climate change, Akiba said.

"Resiliency is the ultimate reliability, and because of climate change, resiliency is the key," Akiba said. "We've heard repeatedly ... resilience is what we need to do in the face of climate change. We're going to try to stop the effect of climate change in the next 12 years, but we've been reminded that in the course of doing that, we also have to have adaptation strategies to deal with the extreme weather and the consequences of what we have failed to do up to now."

Political Will

Phil Scott | © *RTO Insider*

Vermont Gov. Phil Scott said, "Three of our electrical utilities are now 100% renewable, and our largest utility is 60% renewable and 90% carbon-free. We now expect to get at least 75% of our electric supply from renewable energy sources by 2032, and we're putting in place a standard that ... is the most ambitious in the U.S."

Welch said that despite President Trump's denial, in "every state and every region, people know just by what they're seeing that climate change is real, and our failure to act is suicidal. ... A confident country doesn't deny the existence of a problem; a confident country assesses it, analyzes it and solves it. That's what you do, and it's in that effort that you then create wealth."

He contended that a few people doing fine in the carbon-based economy, such as the Koch brothers, are going to fight any effort to transition to a clean energy economy, no matter the consequences to others, but that the upside is jobs created in facing the challenge.

Tim Ashe | © *RTO Insider*

Vermont Senate President pro tempore Tim Ashe said, "We suspect something different is happening ... but still in Vermont, despite our ethic ... there's still a sense that this is really a problem mostly acutely experienced by others, not by us."

David Zuckerman | © *RTO Insider*

Lt. Gov. David Zuckerman, who owns a farm just south of Burlington, said rain that used to fall steadily now comes in torrential downpours, if at all.

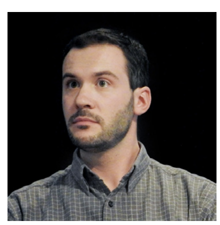
"This year it stopped raining in May, and we drained one pond, and then another, and there was no more water to put on the crops. So now this fall, we have 30,000 fewer pounds of food," Zuckerman said.

He contrasted his situation this year with that of a friend who farms in Shaftsbury, 80 miles south, who said it wouldn't stop raining, and that they had too much water.

Marc Pacheco | © *RTO Insider*

Marc Pacheco, president pro tempore of the Massachusetts Senate, said that while his state has made itself a leader in clean energy and energy efficiency, climate change is becoming more urgent every day.

He recalled talking recently to a friend in Portugal, where Hurricane Leslie had hit last month.



Jared Duval | © *RTO Insider*

"It's the first time in 174 years we've seen hurricane activity in that part of the Atlantic, heading into the Iberian Peninsula," Pacheco said. "It's crazy that we as political leaders ... why we have not put into law the concrete statutes that need to be there and need to be met in order to protect not just our climate, but human public health." Jared Duval of advocacy group Energy Action Network said, "From the evidence that we have reviewed, it appears that the states that have made the most progress are the ones that have renewable policies with teeth."

Mackay Miller | © *RTO Insider*

"The prospects for a strong federal policy are dim ... but at the state level, we can move markets if we move together."

— Mackay Miller, National Grid

Dan Sosland | © *RTO Insider*

Mackay Miller, formerly with the National Renewable Energy Laboratory and now National Grid's director of U.S. strategy, said, "One thing we are now realizing is that the prospects for a strong federal policy are dim ... but at the state level, we can move markets if we move together."

Dan Sosland of Acadia Center said, "We have the will; we need the political will."

No Borders

Marie-Claude Francoeur | © *RTO Insider*

Marie-Claude Francoeur, Quebec's delegate to New England, reminded the audience that "climate change knows no borders."

Quebec didn't join the Regional Greenhouse Gas Initiative "because 99% of our electricity comes from renewable energy, hydropower, so RGGI would not achieve our goals," Francoeur said.

Transportation accounts for about 45% of carbon emissions in Quebec, which began taxing carbon at the distribution level in 2006 with a levy on fossil fuels. Now, with California, it participates in the Western Climate Initiative economy-wide carbon pricing scheme, "investing 100% of the proceeds into greenhouse gas pollution reduction," she said. ■

ISO-NE News

ISO-NE Planning Advisory Committee Briefs: Oct. 17, 2018

Regional System Plan Update

ISO-NE staff made few changes to the Regional System Plan in October, although nearly $30 million were cut from the estimate for the Greater Hartford project in Connecticut by revising a 3.7-mile all-underground 115-kV line to a hybrid overhead/underground line, Director of Transmission Planning Brent Oberlin told the Planning Advisory Committee in an *update* Wednesday.

The RTO reported a $12 million increase in the estimated cost for the Southeast Massachusetts/Rhode Island Reliability Project, reducing the total for all projects in the plan by $18 million since the last update in June to an aggregated estimate of $1.589 billion, Oberlin said.

The cost estimate increased because of two new projects: the West Medway 345-kV circuit breaker upgrades and Medway 115-kV circuit breaker replacements.

Twelve upgrades on the project list have been placed in service since the June 2018 update: four in southwest Connecticut; three around Hartford; and in Massachusetts, a partial rebuild of the 1779 line, a double-circuit tower separation in the Greater Boston area, a reconductor/upgrade on the 112 line, and refurbishment of the Sandy Pond Substation, along with a control house rebuild.

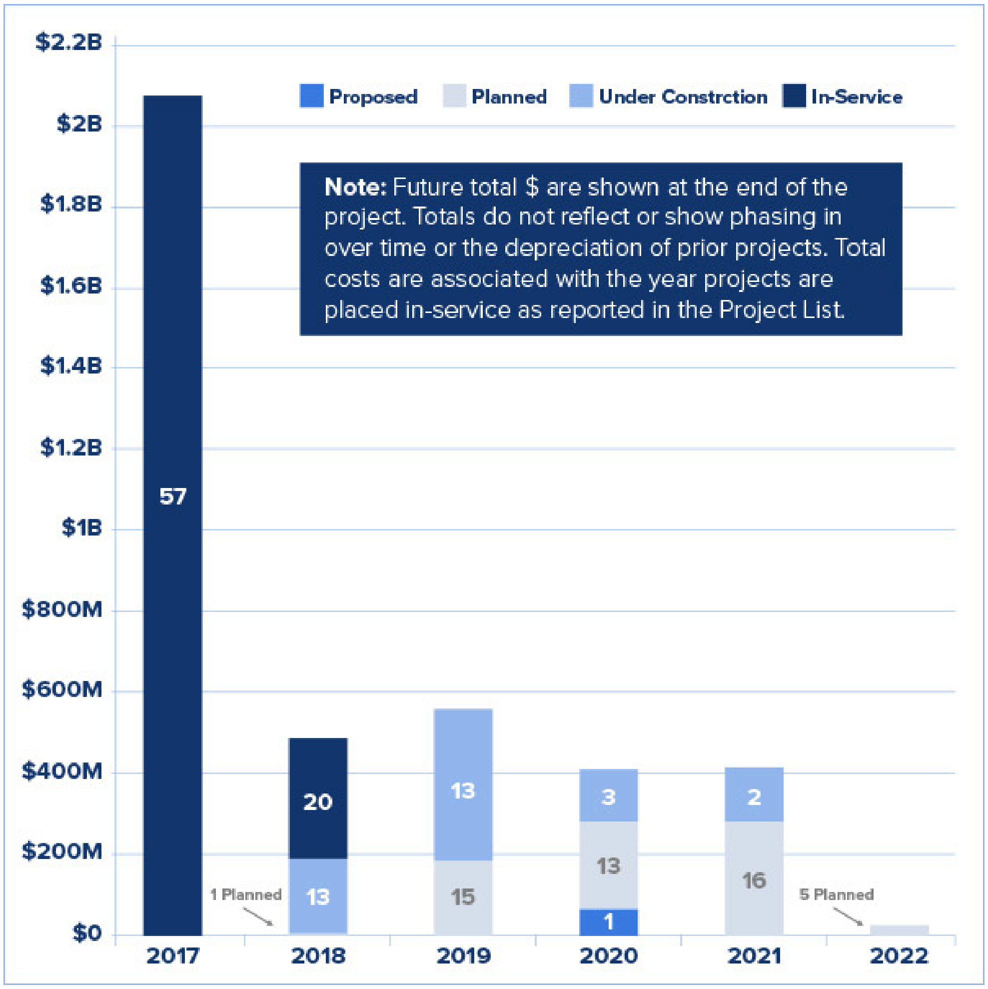
Three new asset condition projects are the Canal Station Project and Robinson Avenue Station Upgrades in Massachusetts, and the Railroad Corridor Transmission Line Asset Condition Upgrades in Connecticut.

Avangrid's railroad project is the most expensive of the three at $376.3 million, "where they're essentially getting off the catenary structures that run along the Metro North railroad corridor and moving onto separate poles," Oberlin said.

Eversource 115-kV Structure Replacements

John Case of Eversource Energy *reported* the utility's work replacing aging transmission towers in Connecticut, Massachusetts and New Hampshire.

The utility is replacing 1,585 structures, or about a third of the 4,400 structures inspected, Case said. Eversource maintains more than 20,000 115-kV structures, about two-thirds of them made of wood.



Investment of New England transmission reliability projects by status through 2022. | *Tx Reliability Projects - ISO-NE*

Connecticut accounts for 63%, or $245.4 million, of the $387.6 million total to be spent on the 2018/19 replacements, which cover about 10% of Eversource's 115-kV infrastructure in the region.

The utility inspects mainly with foot patrols by experienced linemen and high-resolution aerial surveys from helicopters, but a new drone program started last year should be able to survey the whole system within three years, Case said.

Eversource manages approximately 4,000 circuit miles of overhead lines, including around 3,400 structure miles, or nearly 40% of all transmission in New England. The difference between circuit miles and structure miles arises because some structures carry multiple lines, Case said. Their working number is approximately 10 structures to the mile.

Asked whether the spate of storms last March indicated a cost savings to be achieved by putting lines underground, Case said "overheading continues to be an economical and reliable solution to most of our requirements."

Eastern Interconnection Planning Collaborative on Track

Richard V. Kowalski, ISO-NE system planning technical director, *reported* that transmission planning in the Eastern Interconnection is well-coordinated among its planning authorities, ensuring NERC reliability requirements are met, according to a *report* released earlier this month by the Eastern Interconnection Planning Collaborative (EIPC). (See *EIPC Finds Eastern Tx Planning Working Well.*)

Continued on bottom of page 15

ISO-NE News

FERC OKs National Grid LNG Plant

By Rich Heidorn Jr.

FERC on Wednesday approved National Grid's request to add liquefaction facilities at its 600,000-barrel Fields Point LNG storage facility in Providence, R.I.

Customers currently truck LNG to the Fields Point facility for storage, with National Grid redelivering gas via truck or through use of Narragansett Electric's distribution pipelines and Algonquin Gas Transmission's interstate pipeline. "The proposed project would effectively reverse this flow by enabling Algonquin to transport gas that Narragansett Electric would deliver to Fields Point to be liquefied and stored," the commission said (CP16-121).

National Grid said it proposed the liquefaction facilities at the request of Narragansett and a second customer, Boston Gas, which were seeking to diversify their supply sources. It will have a capacity of 20 MMcfd.

Narragansett will provide a dedicated 13-MW, 34.5-kV electric service to power the facility.

Opponents of the project disputed the need for it, saying gas trucked to Fields Point have met peak day demands. But the commission said it was persuaded by storage customers' complaints that they have had trouble obtaining enough LNG supplies.

Commissioners Cheryl LaFleur and Richard Glick joined in the approval but wrote a concurring statement to reiterate their position that the environmental review of such projects should include greenhouse gas emissions.

"We agree with today's finding that the liquefaction facility will not have a significant effect on the environment, particularly given the limited GHG emissions associated with the project," they wrote. "However, we disagree with the language in the environmental assessment that dismisses the social cost of carbon as a useful tool to inform the environmental review, stating the social cost of carbon method 'cannot meaningfully inform the commission's decision whether and how to authorize a proposed project under the [Natural Gas Act].' We believe the social cost of carbon provides a meaningful and informative approach for an agency to consider how its actions contribute to the harm caused by climate change." ■

Fields Point LNG | *National Grid*

Continued from page 14

Entities currently participating in EIPC represent approximately 95% of the Eastern Interconnection load. The biggest nonparticipants are Ontario and the Maritimes provinces in Canada.

EIPC has completed an Eastern Interconnection frequency response analysis to support NERC concerns regarding the changing resource mix. ERCOT is already facing operational issues associated with the trend toward an increasing share of renewable resources generating power, he said.

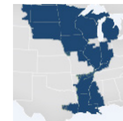
Kowalski explained that one of the bigger concerns with the change in inertial behavior associated with renewable resource technologies is the increased risk of under-frequency load shedding when it shouldn't happen.

EIPC members share costs on a net energy per load basis, and ISO-NE is not even 5% of the interconnection in terms of net energy per load, Kowalski said.

"ISO-NE's share this year would have been around $40,000, but we've been so far under budget that it should be less," he said. The only EIPC staff is a consultant serving as executive director. ■

—Michael Kuser

MISO News



MISO to Turn out Lights on Louisiana Office

By Amanda Durish Cook

MISO's Metairie, La., office location | *Google*

MISO will shut down its regional planning office in Metairie, La., by the end of next year, RTO officials confirmed Wednesday.

The move will leave MISO with three physical locations: Carmel, Ind., Little Rock, Ark., and Eagan, Minn. MISO said it will not renew the lease at the Two Lakeway Center office building in the New Orleans metro area when it expires at the end of 2019. By then, MISO hopes to complete relocation of employees and equipment.

MISO spokesman Mark Adrian Brown said every employee at the Metairie office has the option to relocate to one of the other three offices. He said RTO leadership first disclosed the closure to employees in spring to ensure they had enough time to make relocation plans.

MISO is assisting affected employees with the transition. "We are working with each individual to ensure they have the information and support they need during this process," Brown said.

The RTO has maintained the Metairie *location* since 2012, the year before it officially integrated Entergy's territories into its footprint.

The closure will save MISO money, but it's not clear how much, as the RTO doesn't disclose how much it spends on property. Brown said shuttering the space will help support MISO's "overall organizational health."

"MISO carefully studied a number of factors in the decision-making process. MISO is a steward of our members' resources, and we must always consider the most efficient solutions and opportunities that enhance the value we deliver," Brown in an email to RTO Insider. He added that the move would bring employees together and allow them to collaborate in its remaining and more modern regional offices.

In a 2019 budget *report* to the Audit and Finance Committee of the Board of Directors, Finance Subcommittee Chair Mitchell Myhre of Alliant Energy said the closure will "provide financial benefits in 2019 and beyond." In recommendations this year, the seven-member committee also said MISO should be open to decreasing its scope of operations to cut costs.

MISO's 2019 *budget* has not yet gone before the larger stakeholder community. The Finance Subcommittee will present the 2019 budget to the Advisory Committee on Oct. 24. The RTO is recommending a $312.6 million total operating budget and $27.2 million capital expense budget. MISO's base operating budget, at $269.6 million, represents a 2% increase from 2018. (See "MISO Spending Closely Tracks 2018 Limit; RTO Ups 2019 Budget," *MISO Board of Directors Briefs: Sept. 20, 2018*.) ■

MISO News

MISO Moving to Head off Inverter-based Instability

By Amanda Durish Cook

MISO is hoping to avoid grid instability by possibly requiring inverter-based generation seeking to enter the interconnection queue to provide a specific set of calculations and documentation.

Under the plan, the owner of an inverter-based resource would be required to supply MISO its short-circuit ratio at the point of interconnection before completing an application. The RTO is also contemplating having a project owner either submit a manufacturer statement showing the inverter can operate stably or an Electromagnetic Transients Program (EMTP) study report confirming stable operation. Any project owner unable to prove stable operation will either have to add equipment to raise the short-circuit ratio or reduce the size of the project.

MISO interconnection engineer Warren Hess said the RTO will also disallow use of its "momentary cessation" of active power output from inverter-based resources in order to prevent them from tripping offline unnecessarily. In that case, every generation resource would have to adhere to NERC's *PRC-024-2 standard*, which requires generator owners to set their protective relays to ensure generating units remain connected during defined frequency and voltage excursions.

But stakeholders on an Oct. 16 Planning Subcommittee conference call said MISO might be requiring too much of inverter-based customers too early in the queue process. Some said the RTO should consider asking for short-circuit ratio values later in the queue process because those values will change as projects drop out of the queue. Consultant Roberto Paliza said such information should be provided at the end of the queue's definitive planning phase, adding that MISO should make it clearer what performance standards it requires of inverter-based generation.

But Hess said that short-circuit calculations are relatively easy to provide once customers know the locations of their interconnections. He said MISO wants to avoid entering projects into the queue that ultimately cannot perform without causing harm.

"We are going to be here for guidance to help to calculate short-circuit ratios and coordinate with the applicable transmission owners. Since interconnection customers are deciding where to connect on the system, they should be responsible to work with the transmission owners to get short-circuit ratios for their inverter-based interconnection" MISO Resource Interconnection Planning Manager Neil Shah said.

"Not doing anything is not an option," agreed MISO Manager of Resource Interconnection Arash Ghodsian.

| © RTO Insider

MISO staff also promised to work with interconnection customers and transmission owners to gather information and provide guidance on new interconnection requirements.

"This is going to be a two-way street," Ghodsian said.

Staff said they plan to present draft Tariff language on the possible requirements at the Planning Subcommittee's December meeting. ■

MISO Interconnection Proposals Meet Mixed FERC Rulings

By Amanda Durish Cook

In two orders issued Oct. 12 affecting MISO's generator interconnection queue, FERC rejected a maintenance fee for interconnection customers while also approving a new process for interconnecting external merchant HVDC transmission.

The commission rejected without prejudice MISO's plan to create a new mechanism to allow transmission owners to calculate and recoup expenses related to the operation and maintenance of transmission owner interconnection facilities (TOIFs) (*ER18-1731-001*). TOIFs are "sole use" facilities that includes all infrastructure owned by the TO from the point of the change of ownership (on the system) to the point where an interconnection facility connects to the transmission system.

MISO proposed the "Annual O&M and Overheads Charge" because, while its current generator interconnection agreement makes interconnection customers responsible for all TOIF expenses, the RTO's Tariff currently provides no method for TOs to recover those costs. The proposed charge would have been calculated by TOs and invoiced annually to interconnection customers, treating revenues from the charge as a revenue credit and subtracting it from a TO's net revenue requirement.

MISO and the TOs contended their proposal was consistent with FERC's cost-causation principles because the recovery mechanism ensured interconnection customers would pay their proportional share of maintenance expenses for interconnection facilities, eliminating the possibility that other customers would subsidize the facilities.

But the commission took issue with MISO allowing TOs to calculate the charge using estimated construction costs of the interconnection facilities from the GIA when they cannot determine the facilities' actual costs. FERC said it wasn't just or reasonable to allow use of estimates without requiring TOs to support their figures with a Section 205 filing. FERC also said MISO and the TOs did not provide

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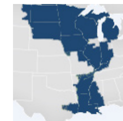


evidence that the estimates would be a "reasonable proxy" for actual construction costs.

The commission additionally pointed out that MISO doesn't file GIAs — which include the cost estimates — when they conform to its pro forma GIA template. It also pointed out the TOs don't typically file detailed cost support for their GIA estimates of interconnection facilities. Consequently, MISO and the TOs essentially asked FERC to "accept the use of estimated values for the purpose of deriving a charge for operation, maintenance and repair of the facilities during their service lives without an opportunity to review the reasonableness of such estimates as a proxy for actual ... costs," the commission said.

FERC added that any future proposal should contemplate a partial-year charge for GIAs that expire midyear.

Merchant HVDC Tx Queue Process Approval

But FERC did accept MISO's proposal to allow external merchant HVDC transmission projects to connect to its grid, effective July 18 (*ER18-1410*). The interconnection process is largely based on MISO's existing queue rules but includes a separate pro forma "MHVDC" connection request form, a pro forma transmission connection agreement and a process for obtaining injection rights, which the project owner converts into external network resource interconnection service (E-NRIS) for its upstream generating facilities. In response to an initial deficiency letter from FERC, MISO explained that it relied on interconnection rules previously approved by FERC and an exhaustive stakeholder process to settle on the new process. (See *FERC: MISO Merchant HVDC Procedures Incomplete*.)

| © RTO Insider

FERC said MISO's plan was reasonable: "Because the MHVDC connection customer will go through MISO's full interconnection process alongside internal generation customers, no issues of undue discrimination or preferential treatment arise between the external generators that may use the E-NRIS converted from injection rights and internal or other external generators that obtain NRIS or E-NRIS, respectively, through MISO's [generator interconnection process]." ■

FERC Upholds Michigan Dam Closure over Safety Fears

By Amanda Durish Cook

FERC last week said that it will not delay its decision to shut down a Michigan hydropower dam over safety violations.

The commission ruled there was no reason to grant a stay of its order to revoke the license of the 4.8-MW Edenville Dam in northern Michigan, saying it only allows such a delay in cases of "irreparable injury" to the petitioner (*P-10808-062*). In this case, the commission said it found no harm other than economic loss.

FERC ordered the dam shut down in February, citing concern over a failure of owner Boyce Hydro to increase the dam's spillway capacity. (See *Michigan Dam Ordered Shut over Safety Breaches*.)

Boyce filed for a stay last month, along with the Sanford Lake Preservation Association, the Wixom Lake Association and the Gladwin County Board of District Commissioners, who wanted to take over dam operations. The D.C. Circuit Court of Appeals on Sept. 25 denied Boyce's motion to stay the revocation order.

In its ruling Thursday, FERC reiterated the dam's 14-year history of noncompliance and safety violations.

"In multiple orders, the commission has set forth a history, going back to 2004, of Boyce Hydro's failure to comply with its license, the commission's regulations and commission orders," FERC wrote. "The commission's primary concern has been Boyce Hydro's 'longstanding failure to address the project's inadequate spillway capacity.' Nevertheless, 14 years after acquiring the license for the project, the licensee has still not increased the project's spillway capacity. The licensee has shown a pattern of delay and indifference to the potential consequences of this failure, which the commission has found must be remedied in order to protect life, limb and property."

FERC also said it was not swayed by the argument by the lake associations and county commissioners that it would be costly and difficult to acquire a new license for the dam.

"Whether Boyce Hydro and the lake associations will reach agreement regarding the sale of the project works is speculative; these entities have not suggested that such a transaction has gone beyond the exploratory stages," FERC said.

Edenville Dam spillway

The shutdown is ultimately in the public interest, FERC said, observing that even the temporary state of the dam during spillway renovations would place the public at further risk: "Boyce Hydro ... notes that to repair the spillways will require the installation of a cofferdam for four to six months, which will reduce the spillway capacity by approximately 50%, increasing the potential for overtopping of the dam." ■

FERC Reduces ITC Adders over Independence Issues

By Amanda Durish Cook

| ITC

FERC last week reduced the return on equity adders previously granted to ITC Holdings subsidiaries for being independent, standalone transmission providers, saying a 2016 merger affected the parent company's autonomy.

The commission's Thursday order said International Transmission Co., ITC Midwest and Michigan Electric Transmission Co. were no longer fully independent because ITC Holdings merged with Canadian and Singaporean companies in 2016. FERC reduced their "transco" adders to 25 basis points each effective April 20, 2018 (*EL18-140*).

FERC had granted ITC and METC 100-basis-point adders in 2003 and 2005, respectively, and ITC Midwest a 50-point adder in 2015.

But in 2016, Canada-based Fortis purchased 80.1% of ITC Holdings, while Singapore government-owned investment company GIC Private Limited acquired 19.9%. As a result, FERC now says the ITC subsidiaries are indirectly owned by two entities "with affiliates that participate in Eastern Interconnection energy and capacity markets."

Tangled Associations

Several utilities had joined the complaint against ITC's transco adders, including Consumers Energy, Interstate Power and Light, Midwest Municipal Transmission Group, Missouri River Energy Services, Southern Minnesota Municipal Power Agency and WPPI Energy. The complainants said the change in ownership meant ITC's companies no longer have the full independence necessary to collect the approximately $24 million in annual revenues from the adders.

The utilities pointed out that Fortis subsidiary FortisOntario uses parts of the grid affected by the loop flow around Lake Erie that is managed by phase angle regulators owned and operated by the ITC companies. Another Fortis subsidiary, Central Hudson Gas and Electric, "generates, purchases and sells electricity over the Eastern Interconnection grid, in portions of New York state that can also be affected by the operation and planning of the ITC companies' MISO-area facilities," they noted.

They also said GIC subsidiary Epsom Investment indirectly owns 44.4% of Duquesne Light Co. and Duquesne Power, which sells retail electricity and markets power within PJM.

Another GIC subsidiary, Camborne Investment, owns a "substantial minority stake" of four generators owned by Eastern Generation. The companies also said a Wisconsin Public Service Commission proceeding shows that "senior executives of the ITC subsidiaries, FortisOntario, Central Hudson, and other Fortis operating subsidiaries meet regularly, outside the Open Access Same-time Information System transparency contemplated by Order No. 889, to 'collaborate on initiatives that are of interest and benefit to the regulated utility subsidiaries.'"

Finally, the complainants argued that "equity infusions from Fortis to ITC Holdings or dividends from ITC Holdings to Fortis may cause generation and transmission investments to compete for capital" and that ITC's proposed 2,000-MW Big Chino Valley pumped storage hydroelectric *facility* in Arizona is evidence that the company is interested in pursuing investments outside of transmission.

ITC Holdings had argued there was "no credible argument" that Fortis, GIC or their affiliates are market participants in MISO and therefore could not affect its independence. The company also contended that FERC analyzes market participation for transco adders on an RTO basis, not an interconnection-wide basis, and pointed to NextEra Energy owning more than 38 GW of generation in the Eastern Interconnection. It also said it continues to be governed by an independent board of directors and is party to a shareholders' agreement with Fortis that restricts ITC equity securities holders from MISO market participation.

The company said "nothing has changed in ITC Holdings' planning of, investment in or operation of its transmission systems under the ownership of Fortis and GIC."

But FERC said ITC's merger "has reduced, but not eliminated, the ITC companies' independence from market participants." The commission relied on criteria in its Order 679 to scrutinize ITC's independence and examined investment planning, capital formation, investment processes and business structure. In several areas, FERC found ITC still demonstrated "some level" of independence.

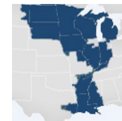
"We acknowledge certain minor potential conflicts of interest associated with other assets owned by Fortis and GIC may exist. However, such concerns are largely attenuated by the location of such assets and the fact that they are largely subject to small ownership shares by Fortis and GIC. Moreover, ITC's and MISO's actions have indirect and limited effects on their other affiliates or subsidiaries," FERC said.

The commission said a 25-basis-point adder "appropriately encourages the transco business model in these circumstances and promotes corresponding consumer benefits."

Commissioner Richard Glick dissented, saying the ITC companies are no longer sufficiently independent to justify any ROE adder.

"Fortis, which owns 80% of the ITC companies, assesses capital expenditures on a consolidated basis, meaning that in evaluating how to allocate capital among its subsidiaries, it is directly comparing investments in transmission with investments in other aspects of its business," Glick wrote. "Even though the ITC

MISO NEWS



companies are permitted to develop their own capital and business plans, Fortis and GIC retain ultimate authority with respect to those plans."

ITC Reaction

An ITC spokesperson said the company was disappointed in FERC's "failure to fully recognize our independence" and is reviewing its options, including rehearing and appeal.

"While the order acknowledges value in our business model, the commission found ITC to be less independent post Fortis ownership," the spokesperson said in an email to RTO Insider.

ITC also recognized the issue could spark a review of transmission incentives.

The "order was characterized as a compromise solution, and several of the commissioners spoke to the need for a broad review of all transmission incentives. Such a review will provide an opportunity for a more expansive review of this and other transmission incentives offered under FERC's policy statement," the spokesperson said. "ITC will advocate that any change to current policy should take into consideration previously approved incentives, which were relied upon by developers to construct facilities that provide ongoing benefits to customers." ■

MISO Stakeholders Rally to Save Interconnection Task Force

By Amanda Durish Cook

MISO's Planning Advisory Committee will vote through Friday on whether to convert the longstanding Interconnection Process Task Force (IPTF) into a working group in an effort to save it from retirement.

The RTO last month proposed to end the task force and fold its discussions and duties into the Planning Subcommittee, a proposal that proved controversial for some stakeholders. (See *"End of IPTF?" MISO Queues up Interconnection Options*.)

MISO planners are still pulling for retirement, but many stakeholders continue to support converting the task force into a working group, as evidenced by discussion during an Oct. 17 PAC conference call where the Transmission-Dependent Utilities sector introduced a *motion* to vote on a makeover. The IPTF itself had already voted to convert itself into a working group. PAC voting results are considered advisory, not binding, for RTO staff.

"I think more folks agree that talk isn't winding down around interconnection issues. If anything, it's ramping up," said Clean Grid Alliance's Rhonda Peters, pointing out that MISO still has a great deal of interconnection work ahead of it based on the size of its 90-GW interconnection queue.

Peters asked the RTO to convert the task force into a more permanent working group so interconnection issues can continue to receive detailed discussions. She argued that the Planning Subcommittee doesn't have the time to fully explore interconnection topics during its meetings.

"There is no doubt that years ago, the IPTF should have transitioned into a working group," Independent Power Producers sector representative Mark Volpe said, noting that MISO's storage participation model under Order 841 will raise policy issues involving the queue with which stakeholders will need to grapple. "There's a lot of work left to be done," he said.

"Squelching stakeholder voices on interconnection rule and policy matters is a bad idea based on the breadth of concern about the subject," Apex Clean Energy's Richard Seide said.

MISO planners at the meeting said they still recommend folding the IPTF into the Planning Subcommittee, although this time they styled the idea as a "consolidation" of the two by the end of 2018.

Resource Utilization Director Vikram Godbole said the RTO is now recommending a consolidated *Transmission and Interconnection Planning Subcommittee* (TIPSC), with a new charter and meetings held on an as-needed basis. The subcommittee would report to the PAC and "provide subject matter expertise to the MISO planning staff on technical matters related to the transmission and interconnection planning processes."

Vikram Godbole | © *RTO Insider*

Godbole pushed back on the stakeholder suggestion that the RTO is trying to exclude some stakeholder voices with its proposal.

"That's not the intent at all," he said, adding that it's always MISO's goal to have well-rounded proposals influenced by a wide range of stakeholders.

Madison Gas and Electric's Megan Wisersky said she "couldn't think of a group more ill-suited" to take on interconnection issues than the PAC. She said a power imbalance exists within the group.

"For one, the PAC is sector-focused and not stakeholder-focused. We need the ideas of the stakeholders" to inform interconnection issues, Wisersky said.

In response to stakeholder questions about how MISO and the PAC would resolve an impasse on the IPTF's fate, Senior Director of Expansion Planning Jeff Webb said the results of a PAC vote and the RTO's preferred approach will both be put before the Steering Committee for further discussion.

But some stakeholders support retirement of the decade-old IPTF. Great River Energy's Mike Steckelberg said he and *other utilities*, including Entergy, Northern Indiana Public Service Co., Duke Energy and Vectren, agree with MISO's proposal to dissolve the IPTF effective January 2019.

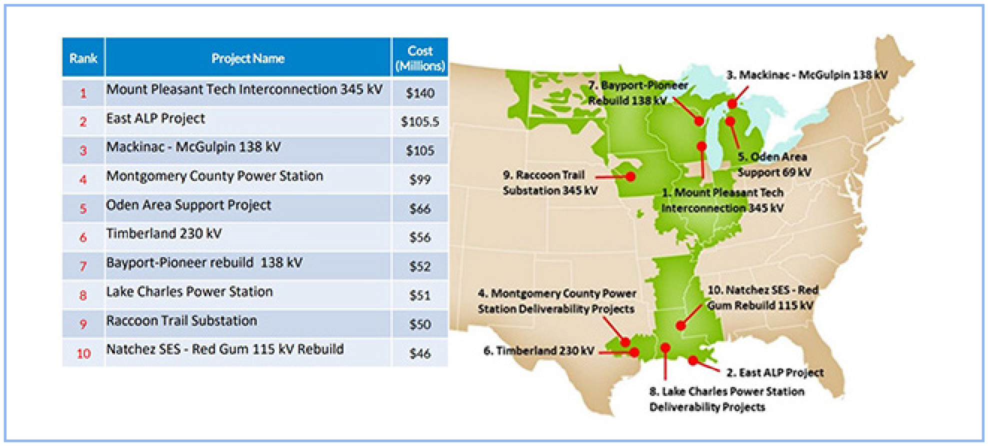
"The IPTF has delved into discussions which are the responsibility of the transmission planners," Steckelberg *said*. "Transmission planners have the engineering expertise, judgment and responsibility to determine what reliability studies are needed to interconnect new generation, and this is best done in the [Planning Subcommittee] forum." ■

MISO News

MISO PAC Puts MTEP 18 to Vote, Removes 3 Projects

By Amanda Durish Cook

MISO's Planning Advisory Committee will vote through Oct. 26 on whether to move most of the RTO's $3.3 billion 2018 Transmission Expansion Plan forward, while holding off on considering approval for three projects because of stakeholder concerns.



Rank	Project Name	Cost (Millions)
1	Mount Pleasant Tech Interconnection 345 kV	$140
2	East ALP Project	$105.5
3	Mackinac - McGulpin 138 kV	$105
4	Montgomery County Power Station	$99
5	Oden Area Support Project	$66
6	Timberland 230 kV	$56
7	Bayport-Pioneer rebuild 138 kV	$52
8	Lake Charles Power Station	$51
9	Raccoon Trail Substation	$50
10	Natchez SES - Red Gum 115 kV Rebuild	$46

Most expensive MTEP 18 projects | © *RTO Insider*

The PAC agreed to consider 439 of 442 projects in its email ballot, reserving three for additional stakeholder comment next week. The committee's vote will take place via email until 4 p.m. EDT on Oct. 26. The committee was originally slated to take a position on *MTEP 18* during its Oct. 17 conference call, but it delayed the vote to address stakeholder concerns with projects.

The portfolio, which was updated late last week with more projects, now contains 81 baseline reliability projects, 16 generator interconnection projects, two transmission deliverability service projects and two targeted market efficiency projects with PJM. (See *MISO, PJM Endorsing 2 TMEPs for Year-end Approval*.)

Most projects fall under MISO's "other" designation: those chosen by transmission owners and reviewed by the RTO that are not eligible for cost allocation and represent replacement of aging infrastructure, construction because of local reliability needs or modifications made for environmental purposes. The portfolio will be considered for approval at MISO's year-end Board of Directors meeting in December. An earlier version contained 434 transmission projects valued at $3 billion. (See *MISO Recommending $3B MTEP 18 Draft Plan*.)

Three Projects

The three problematic projects that won't make the PAC vote include an $11 million rebuild of the Wabaco-Rochester 161-kV line in southern Minnesota, which was identified in this year's market congestion planning study. MISO claims that the project will yield a 6.8:1 benefit-cost ratio, but stakeholders are skeptical of that estimate.

The Wabaco-Rochester line already experiences congestion, with increased traffic expected from wind generation coming online. Some stakeholders have said the project should be delayed in favor of a future larger project.

Others suggested that the amount of future wind generation driving the project's benefits might not ultimately be able to connect.

"We do not support the results on this project," Xcel Energy's Drew Siebenaler said. "A lot of our reasoning is coming from study results that are CEII [critical energy/electric infrastructure information], so I can't disclose them in public comments."

MISO staff said the RTO continues to believe Wabaco-Rochester is a beneficial project and that it studied higher voltage alternatives before drawing that conclusion.

Dairyland Power Cooperative's Terry Torgerson said the cooperative's lawyer would be reaching out to MISO with its concerns over the project. "We've had discussions with MISO many, many times, and we feel we're getting nowhere," Torgerson said.

Entergy's Yarrow Etheredge asked for more discussion and a possible email vote to find out if stakeholders support the project. MISO ultimately opened a longer stakeholder comment period on it.

Straits Project

Kavita Maini, economist for Midwest Industrial Customers, said the MTEP18 report seems incomplete because MISO is still considering alternatives to American Transmission Co.'s Straits of Mackinaw project.

MISO executives in September said they were still weighing alternatives to ATC's proposal to replace a 138-kV circuit connecting Michigan's Upper and Lower peninsulas after two submarine cables were damaged in April, most likely by a passing vessel. ATC said one of the cables was rendered permanently inoperable. (See *ATC Restores Tx Link Between Michigan Peninsulas*.)

"You're right, that's a project whose final recommendation is still in progress with MISO," said Jeff Webb, the RTO's senior director of expansion planning.

Webb said the RTO will continue to work with the parties involved on the project and will deliver an update at the Nov. 13 meeting of the System Planning Committee of the Board of Directors. For now, the project has encountered "complicated siting issues at the straits," though MISO still expects to recommend a replacement of the underwater cables, he said.

Stakeholders have submitted *alternatives* to the straits project that include battery storage, relocating generators from Michigan's Lower Peninsula to the Upper Peninsula, tunneling the cables in bedrock below the lake, connecting to Ontario's grid and constructing a new gas-fired plant near Mackinac.

"We still have hopes of having this resolved before the December recommendation to the Board of Directors, but there is a possibility that it could linger beyond that," Webb said.

"It doesn't seem right to vote on this today when the projects aren't fully vetted," Maini said.

WPPI Energy's Steve Leovy said ITC Midwest's $11 million line and transformer project at the Walters 161/69-kV substation in southern Minnesota was also under evaluation against alternatives, with MISO choosing one such alternative instead of the originally proposed project.

Webb agreed that MISO should update the MTEP report to reflect the change, and the original project was removed from PAC voting consideration. ■

NYISO News

NYISO Proposes Border Pricing Plan for Carbon

By Michael Kuser

RENSSELAER, N.Y. — NYISO last week floated a carbon pricing proposal that would leave importers and exporters to manage the risk of predicting carbon charges for real-time imports into New York, rather than saddling consumers with that uncertainty.

NYISO staffer Nathaniel Gilbraith *recommended* that New York's Integrating Public Policy Task Force (IPPTF) apply carbon charges to external transactions such that they compete with internal resources and each other as if the ISO were not applying a carbon charge to internal suppliers.

Gilbraith cautioned that adopting a carbon charge without considering the pricing effects at New York's borders would likely cause large shifts in import and export dynamics because in-state suppliers would carry an additional cost burden not shared by external suppliers.

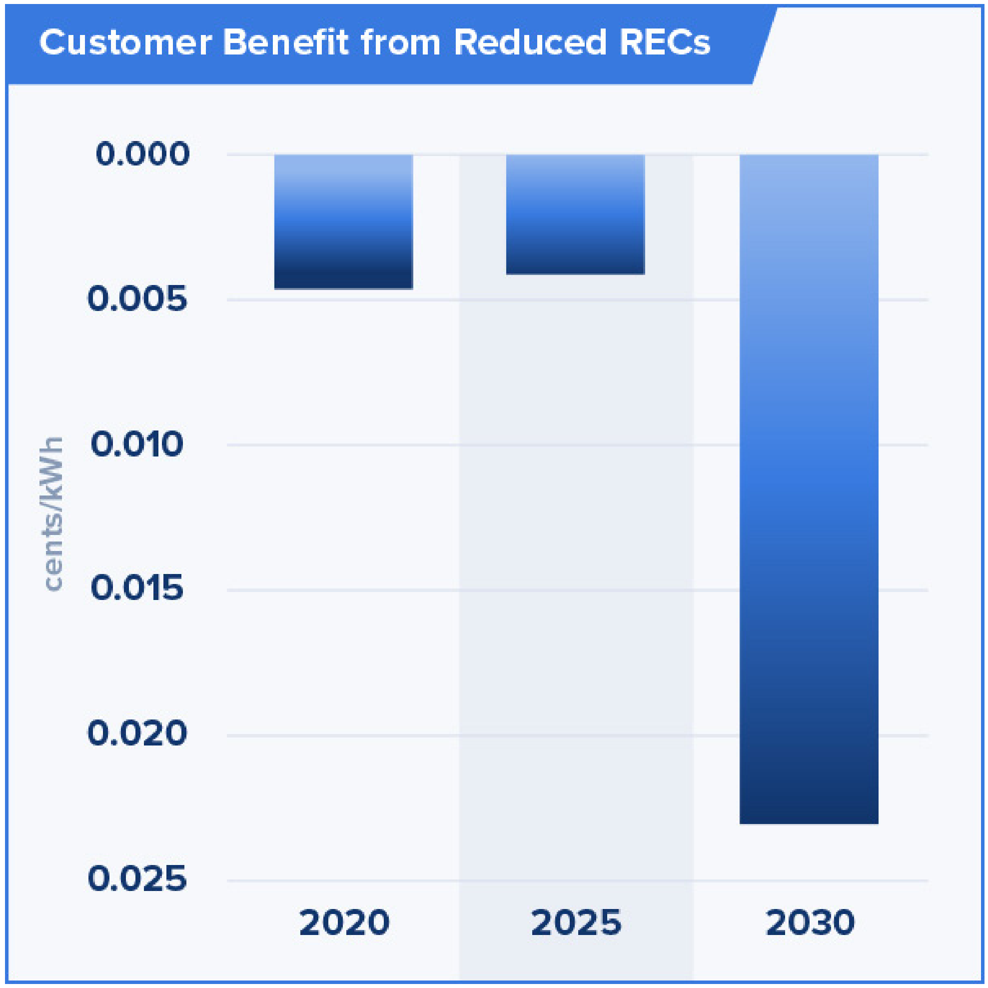
"Total carbon emissions as a result of not addressing this seams issue are up in the air and would depend on whether or not external marginal generation is more or less efficient than internal New York Control Area marginal generation," Gilbraith said. "However, one thing is certain: There would be large financial implications."

Under the plan, NYISO would base the carbon impact on locational-based marginal prices (LBMPc) on the real-time system dispatch to determine carbon charges and credits, as opposed to forecasting the impact. The change would be consistent with the LBMPc used to allocate residuals to loads, and the ISO would also create a new billing code for carbon charge settlements.

By basing the LBMPc on real-time system dispatch, the ISO would not be required to produce a binding forecast of the carbon impact, and energy traders would bear the risk of carbon impact uncertainty.

Several stakeholders took exception to the "big change" in the way NYISO does business, but IPPTF Chair Nicole Bouchez, the ISO's principal economist, said energy traders would be privy to the same information as the grid operator and have the ability to manage that risk.

"Where we landed is that it really wasn't the best place for consumers to bear that risk because they don't have the hedges available to [traders] and because the marketers have both the ability to manage the risk and also in many ways the direct incentive to manage that risk," Bouchez said.



The IPPTF is attempting to ensure that consumers derive the maximum benefit from carbon pricing through reduced payouts for RECs. | *The Brattle Group*

With the new separate line item for a carbon charge on bills and invoices, an import will see both a payment equal to the LBMP and a charge equal to the LBMPc, Gilbraith said.

"Carbon charges and credits will only occur if the transaction flows in real time," Gilbraith said. "For example, if an importer receives a day-ahead schedule at a certain $50/MWh, and they buy out of that schedule prior to flowing in real time, they will not be responsible for any real-time dispatch carbon charge because the transaction did not flow."

NYISO is targeting the Oct. 22 or 29 task force meeting to discuss LBMPc calculation and transparency of data with stakeholders. RTO Insider will have coverage of the Oct. 22 meeting in next week's newsletter.

Updated Analysis

Sam Newell of the Brattle Group described an updated analysis as "essentially the same report" as presented Sept. 17, he said. (See *NY Study: Minimal Price Impact from Carbon Charge*.)

The study assumed lower-emission dispatch leading to a need to buy fewer renewable energy credits to meet the Clean Energy Standard decarbonzaion goals, "so if you get this low-cost emissions abatement through the carbon price, you don't have to do quite as much higher-cost abatement," Newell said.

The effect is "not very big because it's assessed at the REC price post-carbon charge, which is

NYISO News

quite low, but that's always been there and it ends up being trivially small," he said.

The grid operator the previous week had recommended steps to prevent certain wholesale market suppliers, designated as carbon-free in the CES, from collecting double payments for carbon emissions reductions that have already been captured by REC contracts. (See *NY Carbon Task Force Looks at REC, EAS Impacts.*)

The ISO proposed applying a carbon charge to wholesale market suppliers with active, fixed-price REC contracts with the New York State Energy Research and Development Authority that are based on a REC solicitation that began or was completed prior to the carbon pricing rules taking effect, which the ISO estimates to be the second quarter of 2021 at the earliest.

Clawback Issues

The Brattle study accounted for pre-2020 RECs getting a so-called "clawback," and Newell emphasized that "we're not endorsing that at all; that's a very tricky issue. That was our assumption because it was a proposal by New York ISO."

Warren Myers, Department of Public Service director of market and regulatory economics, asked, "If New York doesn't change its policy and index future contracts, do you think the clawback might have an effect on that discount, on how much of that credit is translated into these future REC contracts?"

"Yes, in general it raises regulatory risk with the state on anything," Newell said. "I think there are a number of fairly compelling arguments why not to do it."

The perception of a double payment is not quite accurate, and a clawback carries a lot of potential unintended consequences, Newell said.

He said including pre-2020 RECs poses questions: Was the REC payment generators were receiving unambiguously just for carbon or for something else? To what extent did the suppliers already offer a lower price because of the potential upside from getting carbon pricing?

"There also may be some hedging instruments that would have the effect, if you gave them a lower price at their generation node, of impoverishing the generation owners," Newell said. "They'd actually be losing money if you clawed back the carbon component of the LBMP."

Rule changes create regulatory risk in general and not just for the next REC payments, he said.

"Even if you believe that these REC prices were based on a view of the world that would never have carbon pricing and was fully just compensating them for their nonemitting attributes, the carbon component of the LBMP would be too much to claw back because there are dynamic effects that have already lowered the energy and capacity prices," Newell said.

Looking Ahead

Michael DeSocio, NYISO's senior manager for market design, listed the stakeholder requests so far for additional analysis, such as considering assumptions of a higher social cost of carbon or different RGGI values for 2030. The ISO will prioritize the requests and recommend what analyses the task force undertakes, he said. ■

Brad Jones out at NYISO

General Counsel Named Interim CEO

By Rich Heidorn Jr.

CEO Brad Jones abruptly left NYISO last week and will be replaced, at least temporarily, by General Counsel Robert Fernandez.

Former NYISO CEO Brad Jones (left) and acting CEO Robert Fernandez | *NYISO*

The ISO's Board of Directors announced Fernandez's appointment as interim CEO in a *press release* Wednesday.

Kevin Lanahan, vice president of external affairs, declined to elaborate beyond the press release, except to say Jones' departure was "a personal decision by Brad."

Stakeholders told RTO Insider that senior ISO officials have told them the news was a surprise to them. "It's a really big mystery … it came out of nowhere," said a stakeholder, who, like others interviewed for this story, asked not to be identified. "Usually there's a transition announced. We're shocked. … We're all sort of in the dark on this."

A second stakeholder said the ISO's vice presidents were not informed of Jones' departure until Wednesday morning — shortly before the press release was issued — so they could brief their subordinates. "Secrets like this don't keep very well. So, the limited subset of people who did know didn't know for long," he said.

Asked whether Jones had fallen out with stakeholders, he said "there's always dissatisfaction" with ISO actions. "I guess they wouldn't be doing their jobs right if they didn't piss most of the people off" occasionally. But he said Jones had a reputation for being "even-handed and open to input. I don't think I've heard anyone say a bad thing about the guy — which is pretty unusual."

Jones, who joined NYISO from ERCOT, was commuting regularly from the ISO's offices to his home in West Texas, according to sources. He had said he would not move permanently to New York while he had school-age daughters in Texas. He did not respond to a request for comment Thursday.

The Board of Directors tapped Fernandez as interim CEO at a meeting Oct. 16. Stakeholders said Jones attended a Liaison Committee meeting with the board the same day and that there was no hint that it would be his last.

Lanahan declined to say whether the board intended to keep Fernandez as CEO or would launch a search for a successor.

NYISO Board Chair Ave Bie, former chair of the Wisconsin Public Service Commission, praised Gonzales in the ISO's release, calling him "extremely talented" and saying he "will ably guide the company as we move forward during this transition period." She did not respond to a request for comment.

Fernandez was named the ISO's general counsel and chief compliance officer in 2000 after stints at Long Island Lighting Co. and independent power producer Sithe Energies. He has been involved in "all aspects of corporate governance, including market participant committee decision-making, appeals to the Board of Directors, as well as enterprise risk management," the release said.

He earned his J.D. from Brooklyn Law School, a Master of Laws in taxation from New York University School of Law and a bachelor's degree from Stony Brook University.

Jones, a registered engineer with a master's degree in finance, joined NYISO in October 2015 from ERCOT, where he had been senior vice president and chief operating officer. Though born in Florida, Jones has spent most of his time in Texas, where he and his wife raised their six children. (See *New NYISO Head Brings Broad Experience*.) ■

Tom Kleckner and Michael Brooks contributed to this article.

NY Ready for 'Average' Winter; Burman Worried

By Shawn McFarland

Commissioner Diane Burman, who voiced concerns with no "stress test analysis" | *New York Public Service Commission*

The New York Department of Public Service assured the Public Service Commission on Thursday that utilities are prepared for the upcoming winter and that customers' bills will be on par with last year's. But Commissioner Diane Burman was worried about possible outliers.

Every number Utility Supervisor Chris Stolicky and his panel presented, including the $800 winter bill customers should expect to see, was based on an "average winter."

Burman was interested in knowing if the DPS had stress tested any of their numbers for an event like the winter of 2013/14, when a polar vortex posted record-low temperatures and drove energy prices far above projections.

"I am concerned, for one, because the Energy Information Administration predicts, nationally, to expect average household bills to rise because of a higher forecast in energy price[s]," Burman said.

Engineering Specialist Paul Darmetko said they had not done any stress testing, but that the chance of electric prices approaching those of the polar vortex winter were "slim-to-none" because of the hedging the utilities have taken.

"If the market price increases by 100%, the utilities have locked into hedges that are 70% of the portfolio, so the customers could really only see about 30% of any market price spike that does occur," he said.

Cindy McCarran, the PSC's deputy director for natural gas and water, said utilities' hedging programs also act as an "insurance policy" against gas price increases.

"Prices may very well spike because of cold weather or something like that, but because our utilities buy a lot of fuel ahead of time [and] lock in the price … our firm natural gas customers are certainly not subject to those big spikes," McCarran said.

NYISO Provided Data	MW
Winter Generation Capacity	41,539
New York Special Case Resources (SCRs)	884
Net Purchase & Sales	1,519
LESS: Total Projected Capacity Outages	(5,618)
NET WINTER CAPACITY RESOURCES	**38,324**
Winter Peak Load Forecast	24,269
Operating Reserve Requirement	2,620
Capacity Margin	11,435

New York Winter 2018-19 Capability & Load | *New York Public Service Commission*

NYISO Provided Data

	2018-19 Typical Portfolio	2017-18 Winter Forecast (11/1/17) $/dth	2017-18 Winter Actual $/dth	2018-19 Winter Forecast $/dth
Physical Storage	34%	2.22	2.14	2.38
Hedged Supply	15%	3.06	2.96	2.85
Flowing Gas	51%	3.14	4.26	3.14
Average Winter Commodity Price		2.83	3.39	2.85

LDC Commodity Portfolio | *New York Public Service Commission*

Burman reminded the panel that stress testing became a topic after the 2013/14 winter. The DPS had acknowledged a need to dive deeper into the numbers, she said, but nothing has evolved since.

"We said [in 2014] that we need to look deeper. Check for scenarios in cold winters. Take most of the coldest winters and do stress test analysis.

"How many negative events are we prepared for? … We need to [do] further study and bring this discussion back."

None of the other commissioners voiced similar concerns.

Stolicky did say earlier in the session that local distribution companies must prepare for "extreme days in normal winters," and noted that last April was one of the coldest Aprils on record in New York. ■

PJM News

Skepticism Lingers Around PJM Price Formation Goals

By Rory D. Sweeney

PJM has already missed its Board of Managers' deadline for revising how it forms prices in its energy market, evoking the question: How much longer will the process drag on?

In April, the board instructed RTO staff to identify changes that could be in place for this winter and asked stakeholders "to deliberate timely" so a proposal could be sent to FERC in the third quarter. (See *PJM Board Seeks Reserve Pricing Changes for Winter*.) Staff emphasized at a meeting of the Energy Price Formation Senior Task Force (EPFSTF) on Oct. 12 that the deadline has passed and asked stakeholders to prepare for a vote at the task force's next meeting on Nov. 1.

"We've missed that [deadline] already, so we're trying to work as expeditiously as possible to respect their request," PJM's Dave Anders said.

However, stakeholders pushed back.

Old Dominion Electric Cooperative's Adrien Ford | © *RTO Insider*

"I really want to be able to respect the board's wishes, and I do respect them. I'm not sure if I can in good conscience honor them. I just don't think we're ready to vote," Old Dominion Electric Cooperative's Adrien Ford said. "I want to get this right, and I don't want a board letter to be the reason we don't get it right."

"I don't want to throw in the towel and say this will take as long as it takes," Anders said in response to the hesitation. He asked stakeholders to come prepared to work toward a vote at the next meeting.

James Wilson of Wilson Energy Economics | © *RTO Insider*

Part of the hang-up might be that PJM has presented all its arguments for why the market should be reformed, and stakeholders aren't convinced. PJM's Adam Keech asked what details the RTO hasn't provided yet.

"There are a lot of eyes on what this group accomplishes," he said.

"For me, the main thing that's been missing and that's always been missing is the motivation for this," said James Wilson of Wilson Energy Economics, who consults for several consumer advocates within the RTO's footprint. "I don't really think you've made the case that reserves beyond [the minimum reserve requirement] are worth several hundred dollars."

The task force has been attempting to resolve concerns that the energy market doesn't properly attract resources with the benefits, or attributes, necessary for grid reliability. In July, PJM unveiled a proposal to procure reserves on a more granular level, along with implementing nodal reserve pricing, a real-time 30-minute reserves product and flexible sub-zone modeling. At a task force meeting last month, PJM's Independent Market Monitor proposed revising the operating reserve demand curve to compare the value of purchasing reserves now to fill potential shortages later, rather than purchasing them later during the peak hours of the day. (See *PJM Price Formation Group Talks Reserves*.)

Monitoring Analytic's Catherine Tyler | © *RTO Insider*

The Monitor's Catherine Tyler revisited the proposal at last week's meeting, explaining that the point of the plan is to avoid turning on more units than necessary while also capturing in prices the cost of operator actions taken to avoid reserve shortages. The proposal prompted skepticism for an apparent disconnect in how paying for reserves now could reduce scarcity risks later in the day.

Tyler said the Monitor's proposal is "selectively targeting the times when the market would procure additional reserves," unlike PJM's. ■

PJM News

PJM Board Investigating GreenHat's Record FTR Default

By Rory D. Sweeney

GreenHat listed its address as 826 Orange Ave., Suite 565, Coronado, Calif. — a UPS store between a nail salon and a RiteAid. | *Google*

PJM's Board of Managers said last week it will conduct an "independent review" into GreenHat Energy's massive default in the RTO's financial transmission rights market.

The investigation comes amid pressure from PJM members for answers regarding the June default, which — with losses expected to exceed $100 million — is likely to be the RTO's largest ever. (See *PJM Reeling from Major FTR Default*.) The board said it will throw open its books in response.

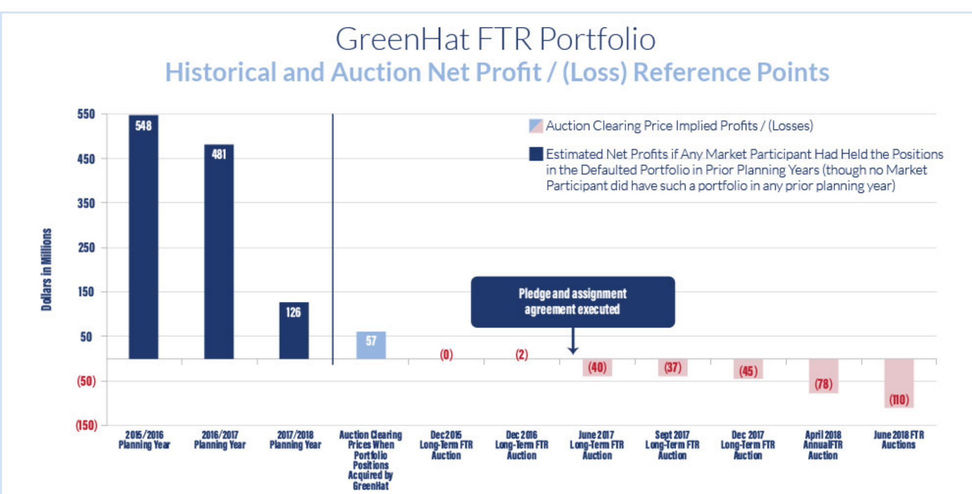
"Examiners will have complete access to PJM records and staff for interviews and documentation review," according to a *news release*.

The default highlighted flaws in the FTR market that allowed GreenHat traders, who had already been linked to a 2013 energy market scandal, to amass the largest-ever portfolio of positions — 890 million MWh — on $600,000 in collateral. PJM has since identified "lessons learned" following a workshop staff conducted with independent experts and addressed many of the gaps through stakeholder-endorsed rule revisions, but member questions still remain. (See *Doubling Down — with Other People's Money*.)

The board has formed a special committee, chaired by board member Susan Riley, that also includes members John McNeely Foster and Mark Takahashi, along with "independent third-party experts." Among the experts are Robert Anderson, executive director of the independent nonprofit Committee of Chief Risk Officers, and Neal Wolkoff, CEO of Wolkoff Consulting Services. Wolkoff was previously chairman and CEO of the American Stock Exchange and chief operating officer of the New York Mercantile Exchange. The Philadelphia firm of Schnader Harrison Segal & Lewis has been retained as counsel.

The committee promises to answer outstanding questions about the default and highlights four goals:

- examine the facts and circumstances associated with GreenHat's participation in the FTR market and its subsequent default;
- assess PJM's actions in connection with GreenHat;
- review lessons learned and make recommendations for the future of FTR markets; and
- address questions raised by the members concerning the circumstances of the default.



PJM analysis shows the continuing downward trajectory of GreenHat's FTR portfolio | *PJM*

PJM members pressed the board for an independent investigation at their Oct. 3 meeting of the Liaison Committee. The committee, which bans media attendance, is an opportunity for PJM members to meet directly with the board several times throughout the year.

East Kentucky Power Cooperative's Chuck Dugan, the committee's chair, detailed members' concerns in an Oct. 10 *letter* to PJM CEO Andy Ott. Dugan said several questions about the default were raised at the meeting, and members are "pleased" the board agreed to the investigation.

The letter outlines six questions members have about PJM's awareness, responsiveness and transparency regarding GreenHat's portfolio, including why staff, after apparently learning about the potential default in February 2017, failed to inform members and instead proposed modifications to the RTO's credit policy for members' endorsement as if they were unprovoked.

Dugan acknowledged the investigation "will require time" but requested progress reports at upcoming Members Committee meetings. A PJM spokesperson could not provide a target date for completing the investigation. ■

PJM News

PJM Preparing for Order 845 Implementation

By Rory D. Sweeney

While the deadline for compliance filings on FERC Order 845 remains at least three months away, PJM is making sure it's prepared.

During an Oct. 16 conference call, PJM staffers Susan McGill and Michelle Harhai *outlined* 10 reforms included in the order, six for which the RTO has already drafted Tariff changes. The remaining four are in progress.

The order, expected to remove even more barriers to storage interconnection, explicitly revises the definition of a generating facility to include storage, permits interconnection customers to apply for interconnection service lower than the capacity of their generating facilities and requires transmission providers to provide interim interconnection agreements for limited operation of generating facilities prior to completion of the full interconnection process.

Energy storage | *SDG&E*

FERC on Oct. 3 granted an extension of the compliance filing deadline to 90 days while it considers multiple requests for rehearing of the order.

Takis Laios of American Electric Power said his company is finishing proposed revisions of PJM's governing documents that it plans to submit for consideration.

PJM's Pauline Foley said the revisions should be submitted "sooner rather than later" and cautioned Laios that because it's a compliance filing, staff are trying to keep revisions "within the scope of [the order]."

"Anything beyond that would really be better handled in the stakeholder process," she said.

Foley also noted that part of the challenge is marrying FERC's order, which make assumptions about what's already in grid operators' tariffs, with what's actually in PJM's Tariff.

"The commission presumes that certain provisions are included in our Tariff, and a lot of the provisions when we originally made our 2003 compliance filing were not exactly as pro forma," she said. With the expanded rules that FERC ordered, "we need to confirm that all of the provisions FERC presumes are there are actually there," she said.

In response to a stakeholder question, Foley added that while "it's not really practical to implement the order" before it's fully been approved, interconnection customers can seek mutual agreements with transmission owners to utilize some of the impending rule changes. ■

Ott Promises to Discuss Capacity at OPSI Annual Meeting

By Rory D. Sweeney

It's a good bet the ongoing FERC paper hearing to revise PJM's capacity construct will be a major topic of discussion at the annual meeting of the Organization of PJM States Inc. (OPSI) at the end of this month.

Ott listening at a Senate Energy and Natural Resources Committee hearing earlier this month | *© RTO Insider*

PJM CEO Andy Ott alluded to the looming debate last week in a *letter* to OPSI responding to the organization's Sept. 26 *correspondence* on the issue. OPSI sent its letter to the Board of Managers just days before the first round of comments were due in the FERC docket. (See *Little Common Ground in PJM Capacity Revamp Filings*.)

FERC ordered the hearing June 29 after concluding that increasing state subsidies for renewable and nuclear power were suppressing capacity prices. The commission's 3-2 ruling required PJM to expand the minimum offer price rule (MOPR) to cover all new and existing capacity receiving out-of-market payments, including renewable energy credits and zero-emission credits for nuclear plants. The MOPR currently covers only new gas-fired units.

The commission's ruling rejected PJM's April "jump ball" capacity filing (ER18-1314), granted in part a 2016 complaint led by Calpine (EL16-49) and initiated a Section 206 proceeding in a new docket (EL18-178). FERC also recommended creating an "FRR Alternative" allowing states to pull subsidized resources — and associated loads — from the capacity auction.

In its letter to PJM, OPSI contended "FERC erred in finding, absent evidentiary support, that PJM's existing Tariff, the status quo, is unjust and unreasonable."

In his response, Ott committed himself and other board members to "be available to discuss these matters with OPSI representatives" at the annual meeting, which begins Oct. 30 in Chicago.

He said PJM "understands the general concern" with accepting the RTO's proposed resource carve-out (RCO) "before adequate resource compensation structures are established." But he warned OPSI that any alternative it suggests must be implemented by next year's Base Residual Auction, which has been delayed until August.

"PJM is open to dialogue on this point but would urge OPSI to ensure that any OPSI proposal in this area reconcile these competing goals," Ott wrote.

He said the alternative OPSI proposed in its letter to the board and supported in the Maryland Public Service Commision's filing in the docket, a so-called competitive carve-out auction, requires that "critical implementation details must be developed before it may be implemented" and that "it is not expected these details can be resolved in time for the 2019 capacity auction." ■

PJM MRC/MC Preview

Below is a summary of the issues scheduled to be brought to a vote at the Markets and Reliability and Members committees on Thursday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be in Wilmington, Del., covering the discussions and votes. See next Tuesday's newsletter for a full report.

Markets and Reliability Committee

1. PJM Manuals (9:15-9:35)

Members will be asked to endorse the following proposed manual changes:

A. Manual 3A: *Energy Management System (EMS) Model Updates and Quality Assurance (QA)*. Revisions developed to clarify the process for considering external bulk electric system facilities for modeling.

B. Manual 13: *Emergency Operations*. Revisions developed as part of PJM's comprehensive security-threat review.

C. Manual 11: *Energy & Ancillary Services Market Operations*. Revisions developed to address FERC approval of Tariff changes related to a new day-ahead pseudo-tie transaction product designed to address overlapping congestion for units pseudo-tied out of PJM.

D. Manual 28: *Operating Agreement Accounting*. Revisions developed to address FERC approval of Tariff changes related to a new day-ahead pseudo-tie transaction product for units that are pseudo-tied out of PJM.

2. RPM Credit Requirement Reduction Clarifications (9:35-9:50)

Members will be asked to endorse draft Tariff *language* to remove an apparent overlapping credit reduction provision for qualified transmission upgrades, to clarify milestone documentation requirements for internally financed projects, and to clarify that capacity market sellers should submit requests for reductions.

3. Transmission Constraint Penalty Factors (9:50-10:05)

Members will be asked to endorse the joint PJM-Independent Market Monitor *package* developed at the special Market Implementation Committee sessions related to transmission constraint penalty factors and draft Manual 11 and Manual 33 revisions, as well as Operating Agreement and Tariff language. (See "Transmission Constraint Relaxation Removed," *PJM Market Implementation Committee Briefs: Sept. 12, 2018*.)

4. FERC Order 831 – Offer Caps (10:05-10:20)

Members will be asked to endorse draft Manual 11 *language* that describes the long-term automated process for price-based offers greater than $1,000/MWh. (See "Automating Offer Confirmation," *PJM Market Implementation Committee Briefs: Sept. 12, 2018*.)

5. 2018 Reserve Requirements Study Results (10:20-10:35)

Members will be asked to endorse the 2018 Reserve Requirements Study *results*. (See "IRM Study," *PJM PC/TEAC Briefs: Oct. 11, 2018*.)

6. Regulation Market Pricing Issue (10:35-10:55)

Members will be asked to endorse a *problem statement* and *issue charge* to address recent regulation market clearing price issues as well present a proposed *solution*. (See "Regulation," *PJM Operating Committee Briefs: Oct. 9, 2018*.)

7. Summer-only Demand Response (10:55-11:20)

Members will be asked to endorse either of two proposals to better value summer-only demand response resources. One *proposal* was endorsed by the Summer-Only Demand Response Senior Task Force, and the *other* was developed by EnerNOC. (See *Plan Would Reduce PJM Capacity Curve Through Peak Shaving*.)

Members Committee

Consent Agenda (1:20-1:25)

Members will be asked to endorse proposed Tariff and OA *revisions* developed by the Governing Documents Enhancement & Clarification Subcommittee.

1. Opportunity Cost Calculator (1:25-1:45)

Members will review progress to date on PJM's review and approval of the Monitor's opportunity cost calculator and then be asked to approve proposed OA Schedule 2 *revisions* related to opportunity cost calculators. (See "PJM, Monitor Come to Agreement on Opportunity Cost Calculator," *PJM MRC/MC Briefs: Sept. 27, 2018*.)

2. M15: Cost Development Manual Biannual Review (1:45-1:55)

Members will be asked to endorse draft *revisions* to Manual 15 developed through the required biannual review, which include addressing terminology inconsistencies and updating the Handy Whitman Escalation Index.

3. Market Seller Offer Cap Balancing Ratio Proposal (1:55-2:10)

Members will be asked to endorse proposed Tariff *revisions* that would change how PJM estimates the expected future balancing ratio used in the default market seller offer cap. The proposed method would take the average balancing ratios during the three delivery years that immediately precede the Base Residual Auction using actual balancing ratios calculated during RTO performance assessment intervals (PAIs) of the delivery years, along with estimated balancing ratios calculated during the intervals of the highest RTO peak loads that do not overlap a PAI for any preceding delivery year with less than 360 intervals (30 hours) of RTO PAIs. (See "Balancing Ratio," *PJM Market Implementation Committee Briefs: July 11, 2018*.)

4. Transmission Constraint Penalty Factors (2:10-2:25)

Members will be asked to endorse proposed Tariff and OA *revisions* related to transmission constraint penalty factors. (See MRC item 3 above.)

5. Super Forum (2:25-2:40)

Members will be asked to endorse a proposed *problem statement* and *issue charge* related to potential *enhancements* to the stakeholder process developed in response to feedback gathered in the Stakeholder Process Super Forum held on July 25, 2018. (See *Poll: PJM Stakeholder Process Imperfect, Necessary*.)

6. 2018 Reserve Requirements Study Results (2:40-2:50)

Members will be asked to approve the 2018 Reserve Requirements Study *results*. (See MRC item 5 above.)

7. Nominating Committee (2:50-3:00)

Members will be asked to elect members of the 2018/19 Nominating Committee. ■

—Rory D. Sweeney

SPP

SPP MMU: Evergy Changing Market Dynamics

By Tom Kleckner

Great Plains Energy's merger with Westar Energy in June has increased market concentration in the new company's reserve zone, but it "is not necessarily a cause for concern at this time," SPP's Marketing Monitoring Unit said in its most recent quarterly State of the Market *report*.

The new company, Evergy, is the largest energy consumer in SPP, accounting for 19.7% of summer consumption, according to the Oct. 15 report, which covers June through August.

Evergy, American Electric Power (17.1%), Oklahoma Gas and Electric (11.6%) and Southwestern Public Service (10.2%) consumed almost 60% of the RTO's total energy in the summer, pushing the market's post-merger Herfindahl-Hirschman Index (HHI) above 1,000 at times, indicating a "moderately concentrated market."

"If a continually increasing trend is observed in the future, it would require further analysis," the report says.

Market participant	June-August 2018 Energy consumed (GWh)	June-August 2018 Percent of system
Evergy	14,968	19.7%
American Electric Power	12,951	17.1%
Oklahoma Gas and Electric	8,794	11.6%
Southwestern Public Service Company	7,766	10.2%
Basin Electric Power Cooperative	5,041	6.7%
The Energy Authority, NPPD	3,711	4.9%
Omaha Public Power District	3,359	4.4%
Western Farmers Electric Cooperative	2,311	3.0%
Golden Spread Electric Cooperative Inc.	2,186	2.9%
Grand River Dam Authority	1,658	2.2%
Empire District Electric Co.	1,505	2.0%
Sunflower Electric Power Corporation	1,443	1.9%
Arkansas Electric Cooperative Corporation	1,242	1.6%
The Energy Authority, CU	1,043	1.4%
Western Area Power Administration, Upper Great Plains	1,034	1.4%
Lincoln Electric System Marketing	1,034	1.4%
Oklahoma Municipal Power Authority	956	1.3%
Kansas City (KS) Board of Public Utilities	754	1.0%
Midwest Energy Inc.	527	0.7%
Kansas Municipal Energy Agency	490	0.6%
Northwestern Energy	448	0.6%
Tenaska Power Service Company	404	0.5%
City of Independence	350	0.5%
Missouri River Energy Services	343	0.5%
East Texas Electric Cooperatives	296	0.4%
Municipal Energy Agency of Nebraska	283	0.4%
Kansas Power Pool	272	0.4%
City of Chanute	142	0.2%
Missouri Joint Municipal Electrical Utility Commission	132	0.2%
City of Fremont	127	0.2%
Big Rivers Electric Corporation	81	0.1%
South Sioux City, Nebraska	69	0.1%
MidAmerican Energy Company	64	0.1%
Harlan Municipal Utilities	5	0.0%
NSP Energy	1	0.0%
Otter Tail Power Company	0	0.0%
System total	**75,794**	

System summer energy consumption | *MMU*

Evergy has 1.58 million customers in Kansas and Missouri. (See *Westar-Great Plains Merger Wins Final Approval*.)

The Evergy reserve zone's average summer prices were below 2017 levels for July and August, at around $30/MWh and $25/MWh, respectively. June prices were more than $30/MWh, primarily because of higher temperatures and loads across SPP.

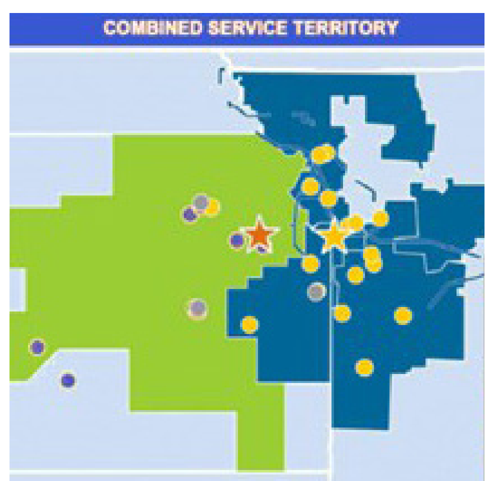
The report notes:

- Low energy prices, with summer prices averaging around $25/MWh;
- A continued decrease in intervals that experienced negative energy prices; and
- A decline in overall congestion across the footprint.

The report's "special issues" section also reviews the market's manual commitment process. The MMU said that while SPP operators have improved their consistency in coding and reporting manual commitments, they should add more detailed and consistent reasons for local, transmission, capacity and stagger commitments.

Noting that FERC *Order 844* in April added market-transparency requirements for resource commitments, the Monitor recommended SPP report publicly all manual commitments. It also noted the high number of manual capacity commitments for ramping needs and renewed its call for a ramp product, saying it would be more effective.

The MMU will host a *webinar* on Nov. 8 to discuss the report. ■



Evergy's territory post merger | *Great Plains Energy*

SPP

FERC Accepts SPP Proposal on Maintenance Costs in Offers

By Michael Brooks

Maintenance workers inspect a turbine. | *Turbine Generator Maintenance*

WASHINGTON — FERC on Thursday approved SPP's proposal to allow generators to include major maintenance costs associated with the number of starts or run hours in their mitigated start-up and no-load offers in the RTO's energy market (*ER18-1632*).

Under the changes, effective Jan. 15, 2019, generation owners will be required to submit each of their resources' maintenance costs to SPP's Market Monitoring Unit. If they're validated, the MMU will then assign the costs by maintenance activity to either the resource's start-up offer or the no-load offer.

SPP said the proposal would not only result in more accurate compensation for generators' costs, but also better help the RTO determine whether to dispatch resources and incent generators to run when dispatched.

The proposal was approved by the SPP Markets and Operations Policy Committee in January and filed with FERC in May. (See "Market Working Group Resolves Mitigation Improvement Issues," *SPP Markets and Operations Policy Committee Briefs: Jan. 16-17, 2018*.)

Stakeholders had debated over what qualifies as major maintenance, and SPP decided to allow only activities agreed to in advance by the MMU and the resource owner to be eligible for cost recovery. Generation owners have 30 days to submit these to the MMU, which estimates that more than half of the 700 resources in SPP will apply to include major maintenance costs in their offers.

"We find SPP's proposal to include a major maintenance cost component in mitigated start-up offers and mitigated no-load offer to be a just and reasonable means of addressing concerns over the recovery of costs resulting from the gradual deterioration of resources' operating equipment in the SPP Integrated Marketplace," the commission said.

The changes received support from the MMU, which had opposed earlier versions of the proposal, as well as City Utilities of Springfield and Golden Spread Electric Cooperative. No one submitted protests.

Chairman Kevin McIntyre did not attend Thursday's open meeting and did not vote on the order. ■

SPP Generator Interconnection Group Wraps up Work

By Tom Kleckner

LITTLE ROCK, Ark. — SPP members last week approved one of two Generator Interconnection Improvement Task Force recommendations but took no action on the second and agreed to disband the group.

The task force was formed last year to identify improvements in the RTO's transmission study process, which is backlogged with more than 62 GW of interconnection requests. Its work will be carried on by various working groups.

The Market and Operations Policy Committee approved the GIITF's suggestion to address generator interconnection studies in regions where the amounts of new generation being requested exceed load during spring and other light load periods.

SPP currently divides its footprint into cluster groups for individual study. In the high variable energy resource case, all VERs inside the cluster are set to 100% of capacity while external VERs are set to 20% to simulate counterflow to the internal generation.

With the increase in VERs, the amount of counterflow contained in the Integrated Transmission Planning models is high enough that the simulation is no longer needed, and the 20% setting has resulted in situations with insufficient load to absorb all the generation being requested. Under the new rules, the external VERs remain at the base reliability dispatch setting used in the ITP process.

"The changes here allow the energy to flow a further distance to a neighboring zone, which should identify [needed] transmission upgrades," said Tradewind Energy's Derek Sunderman.

Task force Chair Al Tamimi, of Sunflower Electric Power, said the change "might help us move forward with [definitive system impact studies]." Staff is working on study requests that date back to 2015.

"That should tell us something," Oklahoma Gas & Electric's Greg McAuley said. "We're dancing around the problem. We have too much generation coming in, and we have no place to put it."

McAuley pointed out that the Holistic Integrated Tariff Team is also

SPP

working on the problem. "We don't know where they're going to land," he said.

The measure passed with six opposing votes, mostly from transmission owners, and 14 abstentions.

Members declined to take a vote on the GIITF's recommendation to change the criteria for allocating network upgrade costs to interconnection customers by adding a new energy resource interconnection service (ERIS) criterion.

Under the proposal, SPP would have first allocated cost responsibility to requests with 20% or more of the generator's output flowing across a constrained element, as under current practice.

After applying the 20% transfer distribution factor (TDF) test, the proposal would have added a second screening to determine which requests have at least a 5% TDF. If the number of such requests resulted in a cumulative TDF of 20% or more, a mitigation would be assigned to the cluster, with the cost allocated to those requests with at least a 5% TDF.

SPP said the change would have resulted in the identification of four additional constraints in the DISIS-2016-001 study.

But several members said the recommendation didn't go far enough in identifying constraints caused by interconnection requests. Staff agreed the current process doesn't catch enough constraints.

OG&E's Greg McAuley (right) states his position as AEP's Richard Ross listens. | © *RTO Insider*

The committee also accepted a storage *white paper* for incorporation into SPP's generator interconnection processes. The document describes proposed rules for processing and evaluating storage interconnection requests. Two members opposed the motion and three abstained. ■

SPP Stakeholders Stop Work on Unreserved Tx Waiver

By Tom Kleckner

LITTLE ROCK, Ark. — SPP stakeholders last week directed the Seams Steering Committee to stop work on proposed Tariff changes that would have granted a waiver from charges for unreserved transmission use across the seams.

The Market and Operations Policy Committee's action during its Oct. 16-17 meeting means SPP's current practices for unreserved use will continue. They have resulted in about $23,000 in service charges since 2016, but only when that unreserved use is reported to the RTO.

The revision request (*RR308*) would have granted transmission customers a four-hour grace period for unreserved service during an unplanned transmission outage. SPP's Tariff and its business practices do not allow exemptions for transmission customers using the RTO's system to take transmission service because of outages, whether planned or unplanned.

The SSC was unable to reach a consensus during its monthslong discussions, with some members saying temporary use of interconnected systems should be a benefit and others calling for transmission owners to be compensated. The four-hour grace period was a compromise position.


Southwestern Public Service's Bill Grant | *RTO Insider*

"Several members thought the four-hour grace period was at least some justification to take this to FERC and stakeholders," American Electric Power's Jim Jacoby, chair of the SSC, told the MOPC. "It seemed to have at least some backing. From an AEP perspective, that's a benefit of interconnected systems. We ought to give customers some time [to arrange service during an unplanned outage]."

RR308 received little support from SPP's legal department. Associate General Counsel Mike Riley pointed to excerpts from FERC Orders *890* and *890-A*, which address situations where a customer is unaware of changing conditions that result in additional service requirements. Riley said FERC's language does not exempt "any class of transmission customer from the potential assessment of unreserved use

SPP

SPP attorney Mike Riley | © *RTO Insider*

penalties" and refers to entities "serving native load in multiple control areas."

"Not being a FERC commissioner, it's hard to say what the [language] is intended to cover, but when I read words like 'multiple control areas,' that seems applicable to us," said SPP's David Kelley, director of seams and market design.

"If SPP and the stakeholders have a basis for filing and justifying this four-hour window, or grace period, we'll absolutely file it," Riley said.

"But based on 890's provisions, where FERC appears not to make a distinction between reserved use and unreserved use, we've got an uphill battle."

Riley agreed with the concept of a grace period before assessing penalties, saying it should be a business practice in the Tariff.

"We just haven't seen or found a justification that would get us over the 890/890-A hurdle, but it's up to FERC," he said.

Several members suggested SPP could conform its practices with those of MISO — which Southwestern Public Service's Bill Grant said MISO does not apply unreserved charges in similar situations — through their joint operating agreement. But Kelley pointed out, "Even if we address this issue through the JOA, we'll still have to make a filing at the commission. We still have to get around the hurdles of what we're arguing."

"This is not being applied consistently," Grant said. "Only when SPP knows about it."

"What we're trying to do is address the unfortunate bystander that doesn't know what's going on, and only finds out about it when they get a bill," AEP's Richard Ross said.

On the sidelines, some members referred to the TOs who reported unreserved use as "tattletales."

The MOPC's motion passed over 10 opposing votes and five abstentions. ■

SPP Strategic Planning Committee Briefs: Oct. 18, 2018

New Board Chair Proposing Changes to Governance Meetings

LITTLE ROCK, Ark. — SPP Board of Directors Chair Larry Altenbaumer last week unveiled a proposal to reduce the number of face-to-face meetings and add more executive sessions, saying it would improve the board's focus on its strategic plan.

SPP Chair Larry Altenbaumer shares his thoughts on changes to the board meetings. | © *RTO Insider*

While no final decisions have been made, Altenbaumer told the Strategic Planning Committee he is proposing adding two executive time slots to the board and Members Committee's quarterly meetings and eliminating the two non-quarterly face-to-face board sessions. The executive time would be used for discussions with the state regulators' Regional State Committee and the Members Committee.

Altenbaumer called the changes part of the board's "broader evolution," but that he was sensitive to concerns about taking discussions behind closed doors. He said the executive sessions are not intended to be decision-making meetings but will improve the quality of the discussions.

"Does this reduce the transparency of the organization? We want to be very much on guard that does not happen," Altenbaumer said. "We want to ensure that in the forums where decisions are made that all stakeholders have the opportunity to participate. I think [meeting with] an outside resource in a smaller setting provides a greater quality of interaction."

The new chairman, who took his position at the head of the table following April's board meeting, said he was driven by the outcome of efforts to integrate the Mountain West Transmission Group. SPP received pushback late in the process from the RSC and members, who felt cut out of some of the earlier discussions.

The work to integrate Mountain West is officially ongoing, but most Western entities are now focused on securing reliability coordination services from SPP and CAISO with the pending shutdown of Peak Reliability. (See *Peak Reliability to Wind Down Operations*.)

SPP Director Phyllis Bernard in discussion with Evergy's Denise Buffington. | © *RTO Insider*

"Despite a lot of effort and a ton of meetings [with Mountain West], I think we failed at effectively communicating with both the RSC and our members," Altenbaumer said. "I had a lot of one-on-one interactions with members to address an issue. On many strategic issues, there is a variety of opinions on how those items need to be addressed. If we can facilitate a discussion with all members on the Members Committee, we'll get a more robust discussion and up-front direction for all our stakeholder groups to address those issues."

Altenbaumer said the organizational strategy should be determined by the board and Members Committee, but he remarked, "I don't think we've always acted as owners of that strategy." He said he prefers setting aside time to "discuss matters of strategic importance" in place of quarterly reports.

The chairman reassured the SPC that it is still the committee responsible for developing SPP's strategic plan.

SPP

"This is where the technical expertise resides," he said. "I hope there will be dialogue back and forth to ensure we're discussing issues of strategic matters."

Altenbaumer wants to eliminate the board's June education session and the December meeting in which the board approves the budget. The December meeting would become a conference call.

He is also proposing the board delegate to the Markets and Operations Policy Committee decisions "that need not be brought to the board."

SPC Takes No Action on Clean Energy Rule

The committee decided not to have SPP provide comments on EPA's proposed Affordable Clean Energy (ACE) rule, determining there is little to be gained, but much to lose.

In explaining the *ACE rule* to the SPC, Vice President of Engineering Lanny Nickell said the rule is "less onerous" than the Obama administration's Clean Power Plan, which required a 32% cut in emissions below 2005 levels by 2030.

The ACE rule applies only to existing coal-fired plants and does not set a federal carbon-emission rate, requiring states to set unit-specific standards, Nickell said.

"From a reliability perspective, it's a lot more flexible and easier to anticipate than output limitations," he said.

Nickell conducted several CPP studies after its 2014 release. The *final analysis* indicated that a state-by-state compliance approach could result in nearly 40% higher costs than a regional approach.

Nickell said there is no reason for SPP to study the ACE rule's "rate-based approach" or to issue a statement. "I don't have any personal concerns about its reliability implications," he said. EPA has issued an Oct. 31 deadline for public comments.

"We haven't made a quantitative analysis" of the new rule, he pointed out. "It would be an opinion we are offering, what we think the implication of ACE would be. We would be making an opinion without a quantitative analysis."

"I love you guys, but you're thinking like electrical engineers rather than politicians," said Director Phyllis Bernard, who has a strong background in administrative law. "Your opinion, while qualitative, is far superior from the opinion of someone out there who is putting out spin. You can make a difference. If you say nothing, the default position may go back to something you don't want to hear. If you think something in the proposed rule is positive, you should say that."


SPP Director Phyllis Bernard | © *RTO Insider*

Several members urged SPP to rely on the facts — no reliability impact; the market is producing emission-reductions through the dispatch of cleaner fuels — and provide comments.

"If you don't say anything, someone will go on the record and dictate the final rule," said Basin Electric Power Cooperative's Mike Risan.

"Once we say something, it invites questions," Altenbaumer countered. "One of the first questions I would ask is, 'How can you make that assertion if you haven't done any studies?' I don't know why you go down that path if there are no benefits, other than a feel-good."

Mike Ross, SPP's senior vice president of government affairs and public relations and a six-term member of the U.S. House of Representatives for Arkansas, cautioned against going public with comments on the rule.

"If we're not careful, we're going to be labeled pro-environment or anti-environment, pro-coal or anti-coal, pro-Trump or anti-Trump. That's not our job," Ross said.

"Our job is to be fuel agnostic and let the markets choose the fuel source and to focus on reliability. The proposed rule by this administration is going to be adopted, whether we comment or not, and since it won't impact reliability, I don't think we should comment. It'll be tied up in the courts for years. When we are trying to make decisions on 40- and 50-year assets, our country needs a national energy policy that transcends administrations and political parties."

Asked whether the *ISO/RTO Council* has weighed in on the ACE, CEO Nick Brown noted that the industry group was silent on the CPP.

"It's certainly not going to step up as a group and comment on this, as it doesn't appear to have any impact on the bulk power system," Brown said. ■

— Tom Kleckner

SPP

SPP Markets and Operations Policy Committee: Oct. 16-17, 2018

MOPC Approves Changes to Joint Model with MISO

LITTLE ROCK, Ark. — SPP's Market and Operations Policy Committee last week unanimously approved staff recommendations to revise the SPP-MISO Coordinated System Plan by eliminating the RTOs' joint transmission model and the $5 million minimum cost threshold on interregional projects, while adding adjusted production cost and avoided-cost benefit metrics.

October's Markets and Operations Policy Committee meeting | *RTO Insider*

The RTOs have told their stakeholders they will use only their individual regional planning models to evaluate interregional projects. Members on both sides of the seam have complained that a "triple hurdle" has contributed to the lack of interregional projects. (See *MISO, SPP Loosen Interregional Project Requirements*.)

"We have concerns ... about getting rid of the joint model, because it is clear up front that the joint model will determine the way costs are allocated," The Wind Alliance's Steve Gaw said. "We lose that stability in the new process, and it remains to be seen if efficiency gains in the new process will outweigh this risk."

MOPC Endorses Battery Storage as Market Participant

The committee endorsed several market design changes for SPP's compliance filing with FERC Order 841.

RR323 defines batteries as electric storage resources (ESRs), capable of being dispatched and participating in price formation. Excluded as ESRs are those resources that are either contractually barred or physically incapable of injecting energy back onto the grid because of their design or configuration.

The Tariff change also creates a new registration type, "market storage resource," to be used only by ESRs. The resources are not required to use the MSR model but must specify ancillary services offered — e.g., energy, regulation up, regulation down, spinning reserves and/or supplemental reserves — and provide at least a tenth of a megawatt to be eligible for any market product.

"The resource can be committed as a charging resource or as a non-charging resource. It's no different than a regular resource," SPP's Yasser Bahbaz said. He pointed out that pumped hydro, a non-charging resource, already qualifies as an ESR.

Renewable interests were hoping to see more on capacity accreditation but were satisfied to learn that the Supply Adequacy Working Group is considering a four-hour accreditation for ESRs. Existing governing language allows ESRs to qualify for capacity credits if the resource meets the planning criteria's testing requirements.

The measure passed with 10 abstentions.

"Our impression is this has gone little bit beyond what we need to do to comply with the FERC order," American Electric Power's Richard Ross said, explaining his company's abstention. "[SPP] already [has] a storage resource, and it seems to have found a way to operate under the current guidelines."

The MOPC also approved tweaks to the Market Working Group's *RR266*, which modeled joint-owned units as single resources and the committee had approved in July. "Ownership" was changed to "interest," recognizing that the former term doesn't capture stakeholder intent that power purchase agreements and other non-ownership interests be included.

Stakeholders approved the change with one abstention.

MOPC Approves 2 Revised Futures in 2020 Study

The committee agreed with the Economic Studies Working Group's recommendation to study only two futures in its 2020 Integrated Transmission Planning assessment: a reference case and an emerging technologies scenario.

It also agreed with the ESWG that there is no need to study a third future that assumes a carbon adder or carbon-emissions reduction and accelerated emerging technologies. The third future would have increased the 2020 ITP's study costs, adding about 6,600 consulting hours.

ITC's Alan Myers | © *RTO Insider*

ESWG Chair Alan Myers, with ITC Holdings, said many of the third future's assumptions will be included in SPP's first 20-year assessment, which will begin in 2022. "That might be a good vehicle for studying these types of things," he said.

Staff will use the 2019 ITP's two futures as a starting point, adding fossil fuel retirements, ESRs and an increase in utility-scale solar and wind additions to the original assumptions. Both futures will assume coal plants retire at 56 years old, a decrease of four years over previous assumptions.

"We think the shift from 60 to 56 [years] ... is definitely a movement in the right direction," said Keith Collins, executive director of SPP's Market Monitoring Unit, which has joined the ESWG's discussions. "But [based on] what we're seeing in other markets, it's not [reducing] it enough."

MMU's Keith Collins | © *RTO Insider*

Collins favored including the third future, saying SPP's market indicates that uneconomic resources are likely operating, as evidenced by the self-commitment of generation and negative prices.

SPP

"The economics Keith talks about are driven by the inability of a coal plant to recover its fixed costs," Board of Directors Chairman Larry Altenbaumer said. "To a large extent, that fixed cost is subject to the regulatory environment that exists. I'm not at all convinced Future 3 is the right way to [address] that."

SPP Updates Members on Western RC Effort

Peak Reliability's decision to cease operations may slow SPP's pursuit of the Mountain West Transmission Group, but it is also giving the RTO some business with the group.

SPP's Bruce Rew briefs MOPC on recent emergency event coordination with MISO. | © *RTO Insider*

Operations Vice President Bruce Rew told stakeholders the 16 entities who have signed up for SPP's reliability coordinator services include all original Mountain West members: Black Hills Energy (Black Hills Power, Black Hills Colorado Electric Utility Co. and Cheyenne Light Fuel & Power); Colorado Springs Utilities; Platte River Power Authority; Tri-State Generation and Transmission Association; the Western Area Power Administration (Rocky Mountain Region and Desert Southwest Region); and Xcel Energy's Public Service Company of Colorado.

Xcel's surprise April announcement that it was leaving the Mountain West shelved SPP's integration of the group. (See *Xcel Leaving Mountain West; SPP Integration at Risk*.)

That news was followed up by Peak's decision in June to wind down its RC operations by the end of 2019. (See *Peak Reliability to Wind Down Operations*.)

The other entities who have signed up with SPP are: Arizona Electric Power Cooperative; the city of Farmington, N.M.; El Paso Electric; Intermountain Rural Electric Association, in Colorado; Tucson Electric Power; Arlington Valley, in Arizona; and Griffith Energy, also in Arizona.

SPP will continue strengthen its toehold in the West with its RC services, expanding its footprint to 16 states with the addition of Arizona and Utah.

SPP's Western RC will serve approximately 20% of the non-CAISO load in the Western U.S., accounting for 100 TWh of net energy for load, Rew said. A *Western Reliability Executive Committee* and a *Western Reliability Working Group* will provide governance. Three task forces have already been formed: *Congestion Management and Seams*, *RC Readiness* and *West Modeling*.

Rew said the groups are currently populating the transmission models, with the hopes of exchanging real-time data with transmission owners, balancing authorities and neighboring RCs by May 1, 2019. The Western RC is scheduled to begin shadow operations with Peak by Oct. 1, with the cutover set for Dec. 1, 2019.

Rew also briefed the MOPC on the major operations events with MISO in January and September, calling the latter a "success story" because of the improved coordination between the RTOs.

Unseasonably warm conditions in mid-September led to higher loads than forecast in SPP's southern region and in MISO South. When several units tripped, MISO was forced to call a maximum generation alert and a Level 2 Energy Emergency Alert on Sept. 15. SPP sent 300 MW of emergency assistance for three hours to help resolve the situation. (See *MISO: Sept. Emergency Response Improved by Jan. Event*.)

"With our operational preparations, we were able to make it through," Rew said.

HITT Group Continues its Education Sessions

The Holistic Integrated Tariff Team has moved into a second phase of education, listening to and discussing presentations by various stakeholders as it eyes an April 2019 deadline for delivering a report on the optimal alignment of SPP's planning processes, cost-allocation methodologies, and market products and services.

The team, which reports to the board, was only formed in April. (See *SPP's Tariff Team Begins Carving up the Elephant*.)

"I won't disagree that it's an ambitious schedule," said SPP General Counsel Paul Suskie, who serves as the HITT's staff secretary.

The HITT expects to begin its third phase in December, when it will begin drafting its recommendations to the board and Members Committee.

The team meets next Oct. 23 and has *scheduled meetings* through April 2019.

The meetings continue to be limited to team members, with those stakeholders not delivering presentations "encouraged" to call in to listen.

Suskie acknowledged the lack of face-to-face interaction and stakeholders' complaints about technological problems during conference calls. "We tried to line the meetings up with board meetings as best we could, but we haven't been able to do that," he said.

Competitive Transmission Group Kept on Standby

The committee agreed to keep the Competitive Transmission Process Task Force on "hot standby" rather than disband it, should a future Order 1000 issue deserve its attention.

Several committee members agreed with the group's recommendation that it disband, saying its work has been completed. But task force Chair Bill Grant, of Southwestern Public Service, argued the group's expertise should be leveraged by keeping it on standby, rather than disbanding it.

"We had a pretty balanced group of people who had transmission experience and know how projects are put together. We also had financial people who could look at and analyze bidding forms," he said. "If MOPC wants to disband and bring it back up if needed, I would caution you that we have the right people at the table."

Formed in 2015, the CTPTF picked up where a previous task force left off to revise SPP's Tariff to comply with FERC's 2011 order introducing competition to transmission development. The group has worked to improve the competitive process following the first two solicitations, neither of which resulted in an approved project.

Admin Cost Recovery Looks at Demand, Energy Charges

Evergy's John Olsen updates MOPC on the Schedule 1A Task Force. | © *RTO Insider*

Evergy's John Olsen, chair of the Schedule 1A Task Force, told the MOPC his group will propose revisions to SPP's administrative fee recovery mechanism at the committee's January meeting. Olsen said that timeline would give members a year to work with their regulators before final revisions are filed with FERC in 2020.

Olsen said the group favors a mix of demand and energy charges, with market costs recovered through energy charges and planning

SPP

The MOPC chuckled at a photo of the Schedule 1A Task Force's deliberations, featuring SPS' Bill Grant (left) and Tenaska's John Varnell. | © *RTO Insider*

costs recovered through demand charges. Contested issues include scheduling and dispatch costs and what "determinants" should be included in cost allocation calculations, he said.

"The debate has been whether generators or loads pay for all cost," Olsen said.

He shared a picture of Grant and Tenaska's John Varnell, wearing seemingly identical plaid shirts and body language during a task force meeting.

"That's what five hours of talking about denominator billing determinants will do to a person," Olsen said, drawing laughs.

The task force has been asked to simplify the rate structure and include energy transactions into the design. The RTO's administrative fee of 42.9 cents/MWh is budgeted to recover $164 million in the current budget year. The administrative fee is collected on contracts between transmission providers and customers. Point-to-point contracts are billed against reserved transmission capacity, and network service is billed against the prior year's average monthly zonal peak. (See *SPP Stakeholders to Study Admin Fee Changes*.)

MOPC Approves Order 845 Compliance Language

The MOPC easily endorsed the Regional Tariff Work Group's revisions to the pro forma large generator interconnection procedures and large generator interconnection agreement to comply with FERC Order 845. The commission's order is designed to address delays in interconnection queues, a common complaint among SPP's membership.

RTWG Chair David Kays, with Oklahoma Gas and Electric, said Revision Request 325 will not be filed until a pending rehearing request before the commission is resolved, which would likely add another 90 days to the timeline.

The vote was unanimous, with only ITC abstaining.

Consent Agenda

The MOPC rejected a change to the ITP's operational model development, agreeing that ESWG/TWG RR317 would be undoing the Transmission Planning Improvement Task Force's work.

The change would have removed the day-ahead reliability unit commitment to evaluate economic flowgates in planning models. It was removed from the consent agenda, with two members abstaining from the vote.

The committee unanimously approved the rest of the agenda, which included 10 revision requests, updates to the 2019 ITP assessment's scope, removal of references to the SPP Regional Entity from the MOPC's scope, the MWG's annual violation relaxation limits analysis, and charter changes for the *Operating Reliability*, *Operations Training Project Cost* and *Regional Compliance* Working Groups. (RR318 was discussed separately but also passed unanimously.):

- *BPWG RR319*: Standardizes market import service (MIS) over all SPP ties by adding MIS to the Miles City DC tie in Montana, which is partially owned by the Western Area Power Administration.
- *ESWG/TWG RR321*: Cleans up several items, grammatical errors and small improvements in the ITP manual that were discovered since its approval.
- *MWG RR288*: Allows non-dispatchable variable energy resources converting to dispatchable to use control statuses not originally available to them. SPP's control statuses are: offline (the resource is not operating); non-regulating (online and capable of following a dispatch instruction or contingency reserve deployment but not eligible to clear regulation service); regulating (online and capable of following dispatch or contingency reserve instruction, and regulation deployment); and manual (online but not able to follow dispatch; e.g., start-up, shutdown, testing, etc.).
- *MWG RR316*: Updates the multi-configuration (combined cycle) resource market design by adding two additional commitment parameters: group minimum down time and plant minimum down time. Also removes sync-to-min and min-to-off times from the submitted minimum down time or group minimum down time when the resource transitions between operational configurations. The current design only allows individual registered configurations to submit a minimum down time.
- *MWG RR328*: Allows the automation of out-of-merit energy and RUC make-whole payment calculations when a contingency reserve deployment test is issued.
- *MWG RR332*: Corrects protocol calculations from designs implemented in *RR200* (design change for bilateral settlement schedules and over-collected losses (OCL) distribution) and *RR235* (correction to RR200) necessary to ensure bilateral settlement schedules are receiving their correct OCL. The change — which also must be approved by the Regional Tariff Working Group — ensures corrected resettlements back to the original May 1, 2018, release date. The RTWG next meets Oct. 25.
- *MWG RR333*: Modifies four charge types necessary to implement *RR229* (FERC Order 831 compliance) and discovered by staff during a recent settlements system replacement project. It also must go before the RTWG for approval.
- *ORWG RR318*: Changes the contingency reserve requirement calculation to allow the use of the "most severe single contingency" as the basis of the minimum contingency reserve requirement on an hourly basis. SPP said the revision allows it to more accurately and reliably set the reserve requirement.
- *RTWG RR305*: Updates Tariff language following modifications to the aggregate facilities study process by removing the requirement to file a service agreement before modeling new transmission service in the ITP models. Also removes the requirement that SPP issue notifications to construct (NTC) and notifications to construct with conditions (NTC-C) before filing a service agreement. Adds a financial commitment date of four years to the issuance of an NTC or NTC-C.
- *RTWG RR322*: Changes the Tariff and other documents to reflect that the RTO is no longer using U.S. Energy Information Administration data in monthly load forecasts. SPP said the data in the EIA report are not granular enough because they are at the balancing authority level, rather than the local balancing authority level required. In January, the RTO began using forecast data that are available through the NERC system data exchange (SDX) and historical data where forecasts are not available. ■

— Tom Kleckner

FERC & Federal News

Same Story, Different Winter: ISO-NE Braces for Gas Shortages

By Michael Brooks

FERC staff on Thursday led a technical conference on RTOs' and ISOs' reliability preparations for the upcoming winter. | © *RTO Insider*

WASHINGTON — Observers of FERC's technical conference on grid operators' preparations for winter on Thursday would be forgiven if they experienced deja vu.

Most of the RTOs say they are ready; CAISO is keeping an eye on natural gas storage levels but not concerned; and the possibility of fuel shortages during an extended cold spell is keeping ISO-NE officials up at night.

The regions gave similar reports to FERC in 2017 and 2016. (See *New England, SoCal Gas Supplies Top FERC Winter Concerns* and *RTOs Brief FERC on Winter Preparations*.)

"You know, I feel like we're in a long-running production of 'same time next year,' where every fall you come and say, 'We have plenty of capacity, we might not have enough gas, I'm cautiously optimistic we can make it through,'" FERC Commissioner Cheryl LaFleur told Peter Brandien, ISO-NE vice president of system operations.

The National Oceanic and Atmospheric Administration is predicting a warmer-than-normal winter for most of the U.S., including New England. But Brandien *said* it is not the average temperature that concerns him; it's the duration of low temperatures.

"It's not that the electric load increases; it's that the fuel kind of disappears" because home heating takes priority over electricity generation, he said. "Last winter, December, January and February were all above average temperatures and weather. But we experienced extreme cold weather Dec. 26 through Jan. 8, and it's those kind of spells that cause us concern."

When gas is short, ISO-NE relies on oil as backup fuel. But severe weather can cause delays not only for barges shipping in LNG, but for trucks carrying barrels of oil. Generators burning oil also face emission limits.

In their *presentation* to commissioners during their open meeting earlier that day, FERC staff also noted this will be the first winter under ISO-NE's Pay-for-Performance capacity construct, which became effective June 1. The program is intended to better incent generators to perform during scarcity and emergency conditions, and influenced PJM's Capacity Performance construct.

Staff also noted ISO-NE's integration of price-responsive demand into its markets, also implemented June 1. (See *ISO-NE Begins Real-time Dispatch of Demand Response*.)

But being the first years of these programs, Brandien said anything beyond a weeklong cold spell was unknown territory for the RTO.

From left, Peter Brandien, ISO-NE; Emilie Nelson, NYISO; Dave Souder, PJM; Rob Benbow, MISO; Bruce Rew, SPP; and Nancy Traweek, CAISO. | © *RTO Insider*

No Worries Elsewhere

Representatives from the other FERC-jurisdictional grid operators reported that they were able to maintain reliability last winter despite two major cold snaps in January — one including the so-called bomb cyclone — and that they were similarly prepared for this winter.

Emilie Nelson, NYISO vice president of market operations, also *referenced* the late December/early January cold snap, which led to the ISO's third highest winter peak load since 2004, at about 25.1 GW. Nelson said NYISO does not expect any problems this winter, but it is undertaking several efforts to plan for the long term. One of these is a fuel security study next year "to evaluate the ability to meet electric system needs during stressed system conditions, such as prolonged cold weather events and disruptions in fuel availability." (See related story, *NY Ready for 'Average' Winter; Burman Worried*.)

Both Robert Benbow of *MISO* and Bruce Rew of *SPP* noted the mid-January cold snap in the South, when both MISO South and SPP set new all-time winter peaks on Jan. 17 of 32.1 GW and 43.6 GW, respectively.

While MISO maintained reliability through the event, Benbow said the RTO saw opportunities to improve its coordination with members and neighbors. Those lessons helped improve performance during a maximum generation event in September attributed to a major load forecasting error, he said. (See *MISO: Sept. Emergency Response Improved by Jan. Event*.)

Nancy Traweek, executive director of system operations for *CAISO*, said nothing has changed in regards to gas since last winter. Two pipelines in California — Southern California Edison's Line 235-2 and Line 4000 — remain out of service, and her "favorite friend," the Aliso Canyon storage facility, is still a last-resort resource for withdrawals. Rather than winter, Traweek said, the ISO is still concerned about summer.

"Right now we're still considered in summer; it's very warm and dry in California, and really the biggest risk we have right now is the risk of wildfire," Traweek said. "It's becoming a year-round issue. It used to be October would be our big wildfire season, and now we can see it any time of the year." ■

FERC & Federal News

FERC Finalizes Supply Chain Standards

By Rich Heidorn Jr.

| Pixabay

FERC on Thursday approved reliability standards for mitigating supply chain risks in industrial control system hardware, software and computing and networking services. The commission also ordered NERC to develop rules expanding the supply chain protections to include electronic access control and monitoring systems (EACMS).

The commission's final rule, intended to build on existing critical infrastructure protection (CIP) standards, approved NERC reliability standards CIP-013-1 (Cyber Security – Supply Chain Risk Management), CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)) and CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments). The final rule hews closely to the commission's January 2018 Notice of Proposed Rulemaking (*RM17-13*). (See *FERC Backs NERC Supply Chain Standards*.)

The new rules, effective 60 days after publication in the Federal Register, will be implemented over 18 months, as requested by NERC. The commission said the transition was needed because compliance will likely require technical upgrades, with implications for capital budgets and planning cycles that have longer time horizons.

FERC acknowledged the standards did not cover all supply chain risks, giving NERC 24 months to draft rules covering firewalls, authentication servers, and intrusion detection systems.

Counterfeits, Malicious Software

The rules are intended to protect the bulk electric system from counterfeits or malicious software and tampering. They require affected entities to implement security controls addressing: software integrity and authenticity; vendors' remote access; information system planning; and vendor risk management. FERC said the rules will cover 288 reliability coordinators, generator operators, generator owners, interchange coordinators or authorities, transmission operators, balancing authorities and transmission owners.

FERC acknowledged the rules did not cover the supply chain risks of EACMS such as firewalls, authentication servers, security event monitoring systems, and intrusion detection and alerting systems. The commission said NERC must propose rules to address the gap within 24 months. "Once an EACMS is compromised, an attacker could more easily enter the [electronic security perimeters] and effectively control the BES cyber system or protected cyber asset," FERC said.

The commission also noted the standards generally don't address physical access control systems (PACS) or protected cyber assets (PCAs). "We remain concerned that the exclusion of these components may leave a gap in the supply chain risk management reliability standards. Nevertheless, in contrast to EACMS, we believe that more study is necessary to determine the impact of PACS and PCAs," the commission said. "Compromise of PACS and PCAs are less likely. For example, a compromise of a PACS, which would potentially grant an attacker physical access to a BES cyber system or PCA, is less likely since physical access is also required."

Budgets OK'd

The commission also approved NERC's 2019 business plan along with almost $166 million in spending allocated for the U.S. share of funding NERC, its regional entities and the Western Interconnection Regional Advisory Body (WIRAB) (*RR18-9*).

The 2019 budgets include $62.5 million for NERC; $102.8 million for its seven regional entities' funding and almost $630,000 for WIRAB.

Including funding from other sources, NERC's 2019 budget is $79.1 million, an 8.4% increase over 2018. Most of the increase is attributed to expanding staffing and functions at its electricity information sharing and analysis center (E-ISAC). (See *New NERC Chief Not 'Smartest Guy in the Room'*.)

NERC's budget includes 205 full-time equivalents, an increase of six from 2018. ■

FERC & Federal News

Methane Tax Suggested to Reduce Emissions

By Rory D. Sweeney

PHILADELPHIA — Fugitive methane emissions might be reduced throughout the natural gas supply chain by making accidental leaks and routine venting part of the carbon markets being considered for the power industry, panelists told attendees Wednesday at a *policy forum* hosted by The Kleinman Center for Energy Policy at the University of Pennsylvania.

The key would be developing a market that taxes emitters but also pays those who capture emissions, as the technologies would also be useful for reducing methane emitted by nature — either as part of natural processes or negative feedback loops exacerbated by global climate change.

"If you can price greenhouse gas emissions and you put in that financial incentive for capturing it, and then whatever brilliant technology gets developed, it faces the right incentives and it has a financial ability to move forward," said Catherine Hausman, an assistant professor of public policy at the University of Michigan. "The carbon tax, the flip of that is the subsidy or whatever for what gets captured."

She suggested a policy, which she acknowledged has legal concerns, where every potential source of methane in a region would be responsible for a share of the area's emissions unless it can prove it wasn't the source. That would incentivize gas producers and pipelines to monitor their operations to prove themselves innocent.

"I would love to get to the place where methane emissions from the oil and gas industry are appropriately taxed. ... Our view is we're not there yet."

— Ben Ratner, Environmental Defense Fund

The panelists weren't afraid to promote increased governmental regulation.

"Tax the emission if you can. Absent a tax … you need regulations on the way they run. ... I am totally happy with regulatory measures that are not market-based in situations where you can't develop market-based solutions," Hausman said. "I always teach that zero pollution is not the right answer because it stops all economic activity. Now, very aggressive action is certainly needed."

"I would love to get to the place where methane emissions from the oil and gas industry are appropriately taxed. ... Our view is we're not there yet," the Environmental Defense Fund's Ben Ratner said. "Where we really want to get to over time is prevention. ... There's just no way around government action."

Another challenge for developing a carbon market will be defining what values are used to determine payments. As hard as it is to nail down a valuation of carbon — the panelists noted suggestions from $40 to $400/ton — so too is calculating the amounts emitted. And while researchers can estimate global emissions, "knowing the precise location [of the source] is what's hard," Hausman said.

"You have to solve the measurement problem," she said.

"There's still so much uncertainty about global emissions ... that we don't know yet what [each source's emissions limit] should be," Ratner said.

Hausman suggested the key might be locating "super-emitters."

The panelists also criticized the Trump administration for attempting to reverse regulations on methane emissions in the oil and gas industry. The Clean Air Act's procedural rules barred the Obama administration from expanding its more stringent regulations for new and modified facilities to existing facilities, Ratner said.

The hope was for the next administration to make that expansion, he said. But "not only is this new administration not doing that, it seems to be intent to roll back" the Obama revisions, he said. ■

From left, Environmental Defense Fund's Ben Ratner; Catherine Hausman, assistant professor of public policy at the University of Michigan; and moderator Karen Goldberg, a chemistry professor at the University of Pennsylvania and the director of the Vagelos Institute for Energy Science and Technology. | © *RTO Insider*

Company Briefs

Partial Reversal in Entergy Opportunity Sales Case

FERC on Thursday issued a split ruling on challenges to an administrative law judge's July 2017 initial decision assessing $85.6 million in damages over Entergy Arkansas' opportunity sales in a 2009 complaint by the Louisiana Public Service Commission. FERC ruled in 2012 that although Entergy Arkansas had authority under the Entergy System Agreement to sell power to third-party power marketers and others that are not members of the agreement, it improperly allocated lower-cost energy to those sales.

Thursday's order affirmed in part and reversed in part the initial decision on damages, rejecting the ALJ's cap on a bandwidth adjustment as unwarranted. It also reversed the ALJ's assessment of $5.4 million in damages for sales from the Grand Gulf nuclear plants in January through September 2000, which the commission concluded had already been accounted for and did not belong in the damages calculation.

The commission ordered Entergy to make a compliance filing within 60 days explaining how Entergy Arkansas will make the refunds to the other Entergy operating companies.

More: *EL09-61-004*

Clarification, Rehearing in Ameren Illinois Rate Case

FERC on Thursday clarified that it didn't intend for Ameren Illinois to change its formula rate in its January order denying rehearing of a tax-related complaint against the utility. The order had upheld a September 2016 ruling rejecting a challenge to how Ameren accounted for contributions in aid of construction (CIAC) and accumulated deferred income taxes (ADIT).

The commission's 2018 order said, "Neither the tax gross-up of CIAC nor the ADIT related to the tax gross-up of CIAC are allowed to be included in the ATRR [annual transmission revenue requirement]," prompting Ameren to request clarification on whether it must change its filed formula rate to remove all CIAC-related ADIT from the account in question.

FERC said that wasn't its intent. "We clarify that the [order] spoke only to the tax gross-up of CIAC and its related ADIT. However, the commission went further than it intended in the January 2018 order when it directed that the ADIT related to the tax gross-up of CIAC be excluded from the ATRR. The ADIT related to the gross-up is included … in the ATRR per the formula rate template."

More: *ER16-1169-002*

FERC Approves Settlement over Solar LGIA

FERC on Thursday approved an uncontested settlement involving an amended large generator interconnection agreement (LGIA) between Southern California Edison, CAISO and AltaGas in a dispute that arose when AltaGas decided to convert its Sonoran project from a combined cycle plant to a solar PV generator.

EDF Renewables had protested the switch, arguing that allowing the revised project (CAISO interconnection project Nos. 17 and 219) to maintain its full capacity deliverability status would adversely affect two of its own projects that were lower in the interconnection queue, Palen (project No. 365) and Desert Harvest (project No. 643AE). EDF contended the amended LGIA should be rejected or amended to convert the Sonoran project to energy-only deliverability status.

The agreement says that the Sonoran project has complied with all CAISO requirements and that FERC should accept the LGIA as filed. But AltaGas also agreed to convert a portion of its Sonoran project to energy-only status if studies by CAISO and EDF determine EDF's projects would otherwise be unable to obtain full deliverability for 250 MW before CAISO completes its West-of-Devers transmission upgrades.

More: *ER18-156-002*

FERC OKs Clean Energy Connect Tx Pacts; Rejects Incentives

FERC on Friday approved seven bilateral cost-based transmission service agreements (TSAs) for use of Central Maine Power's 1,200-MW New England Clean Energy Connect line but rejected the company's request for incentive adders as moot.

The commission found that the TSAs were presumed just and reasonable under the Mobile-Sierra doctrine because they were individually negotiated, arms-length agreements with sophisticated parties: NSTAR Electric; Massachusetts Electric; Nantucket Electric; Fitchburg Gas and Electric Light and H.Q. Energy Services. That also meant that CMP was not entitled to incentive adders to its return on equity, the commission said.

"In light of our finding that the TSAs are subject to the Mobile-Sierra presumption, we find that Central Maine Power's request for transmission incentive treatment is moot. Regarding Central Maine Power's requested conditional ROE adder, we are not granting the adder because our acceptance of the ROE reflected in the TSAs obviates that request. Additionally, with respect to the request for abandonment, we note that the parties have already agreed to the abandonment provisions memorialized in the TSAs. Accordingly, we need not grant Central Maine Power's request for incentive treatment here."

More: *ER18-2256*

Tesla Buys Land in Shanghai for Auto Factory

Tesla last week announced that it had signed agreement for land to build its first factory outside the U.S., in Shanghai.

The move follows the Chinese government's decision in July to lift restrictions on foreign electric vehicle manufacturers operating in the country. China is the world's largest market for EVs.

The deal allows Tesla to avoid tariffs placed on trades between the U.S. and China.

More: *The Associated Press*

Gates Opens $116M Investment Fund in EU

Bill Gates' Breakthrough Energy Ventures opened a $116 million investment fund for European companies to develop clean technology.

"We need new technologies to avoid the worst impacts of climate change," Gates said in Brussels. "Scientists and entrepreneurs who are developing innovations to address climate change need capital to build companies that can deliver those innovations to the global market."

Breakthrough has taken stakes in companies pursuing fusion energy, energy storage and bio-technologies.

More: *Bloomberg*

Dominion Files to Extend Life of Surry Nuke to 80

Dominion Energy last week filed an application with the Nuclear Regulatory Commission to extend the license for its Surry nuclear plant's two units by another 20 years.

Located in Newport News, Va., the units began operations in 1972 and 1973, and they were approved for another 20 years in 2003. If Dominion's latest filing is approved, their licenses would expire in 2032 and 2033, when they are 80 years old.

Surry is only the third plant in the U.S. to file for an extension to 80, after Florida Power and Light's Turkey Point and Exelon and PSEG Power's Peach Bottom.

More: *POWER* ■

Federal Briefs

Zinke Talks Offshore Wind at AWEA Conference

Speaking at the American Wind Energy Association's Offshore Wind Conference last week, Interior Secretary Ryan Zinke made three announcements for offshore wind developments in California, Massachusetts and Rhode Island.

The Interior Department's Bureau of Ocean Energy Management issued a call for information and nominations from companies interested in developing wind projects off the California coast. The bureau has identified three areas off Northern and Central California totaling 1,073 square miles. Responses are due Jan. 27, 2019.

On the East Coast, the bureau is preparing an environmental impact statement for the South Fork Wind Project, a proposed 15-turbine project 19 miles southeast of Block Island off Rhode Island. Comments on the bureau's notice of intent on the EIS are due Nov. 19.

Zinke also announced that the bureau would conduct the next auction for 390,000 acres of the Massachusetts Wind Energy Area on Dec. 13. Nineteen companies have qualified to participate in the auction.

More: *Department of the Interior*

Interior IG: Zinke Skirted Rules to Travel with Wife

A report by the Interior Department's inspector general, obtained by Politico last week, says Secretary **Ryan Zinke** tried to maneuver around or alter rules to justify traveling on official business with his wife.

Department rules prohibit spouses from traveling in federal vehicles. But Zinke's wife, Lola, often did so, and he tried to find other ways she could travel with him so that he did not have to reimburse the department, according to the report.

The report also says the department spent $25,000 on a security detail for the couple while they vacationed in Turkey last year.

More: *Politico*

EPA: GHG Emissions Fell 2.7% Last Year

EPA announced last week that greenhouse gas emissions fell 2.7% in 2017, mostly on reductions from the electricity industry as coal plants continued to close.

"Thanks to President Trump's regulatory reform agenda, the economy is booming, energy production is surging and we are reducing greenhouse gas emissions from major industrial sources," acting Administrator **Andrew Wheeler** said in a statement.

More: *Reuters*

Heller Introduces Legislation to Lift EV Tax Credit Cap

Sen. **Dean Heller** (R-Nev.) introduced legislation last week that would lift the cap on the amount of purchased electric vehicles eligible to receive federal tax credits.

Customers who purchase an EV are eligible for an up to $7,500 tax credit until a manufacturer sells 200,000 vehicles. Heller's bill would lift the cap entirely, but end the program in 2022.

More: *Reuters* ■

State Briefs

ARIZONA

ACC Commissioner Used APS Talking Points

Emails between Corporation Commissioner **Justin Olson** and Arizona Public Service show the commissioner used talking points provided by the utility when discussing renewable energy and climate change with a Wall Street Analyst.

Clean energy advocacy group Energy and Policy Institute obtained the emails and a recording of a conference call between Olson and the analyst, in which the commissioner repeated, sometimes verbatim, APS' stances on the issues.

Olson said the group was "cherry-picking" parts of the conversation in which he agreed with APS, and that he seeks and receives advice from a variety of sources. "I can defend all the positions I took on that call," Olson said.

More: *The Arizona Republic*

ARKANSAS

Restaurant, Bakery Switching to Solar

Two small businesses in the state announced last week they will be 100% solar-powered.

Community Bakery in Little Rock will partner with Seal Energy Solutions to install a 35.7-kW array at its Downtown location. The bakery will receive both the federal investment tax credit and the state Rehabilitation Tax Credit.

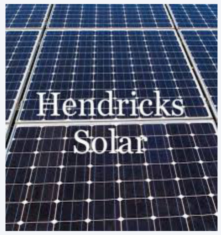
In Bentonville, The Buttered Biscuit restaurant partnered with Shine Solar to install an array that began operation last week.

More: *Community Bakery*; *KNWA*

ILLINOIS

Boone County Approves 200-acre Solar Farm

The Boone County Board voted 11-1 last week to approve what will be the largest solar facility in the county, a 200-acre project developed by Hendricks Solar.



The board approved the 20-MW facility after Hendricks agreed to about 40 conditions, including a 310-foot buffer between it and neighboring properties.

More: *Rockford Register Star*

MAINE

Analysis: Retail Choice Customers Overcharged $16M

An analysis conducted by the Bangor Daily News found that customers purchasing electricity from competitive suppliers last year could have collectively saved $16.6 million if they had received standard offer service.

From 2012 to 2017, customers could have saved a total of $95.3 million, according to the analysis.

Last year's premium is at its lowest, however, as residents and businesses switch back to SOS. At their peak, competitive suppliers served more than 221,000 customers; last month, they only had about 106,000.

More: *Bangor Daily News*

MANITOBA

Former Premier to Lead Investigation into Cost Overruns

The provincial government has agreed to an independent investigation to be led by former British Columbia Premier Gordon Campbell into cost overruns at two Manitoba Hydro projects.

The government-owned utility originally estimated that the recently completed Bipole III HVDC transmission project would cost $2.2 billion (about $1.7 billion USD) but over time the costs have increased to about $5 billion ($3.8 billion).

Meanwhile, the utility is building the 695-MW Keeyask hydro project, originally slated to cost $6.5 billion ($5 billion), ballooning to $8.7 billion ($6.6 billion). However, a consulting firm hired by the Public Utilities Board last year estimated the project could cost up to $10.5 billion ($8 billion) because of the "contractor's poor productivity and increased indirect costs."

More: *CBC News*

MARYLAND

City: Damaged Sewer Main Leaked 1.7M Gallons

The Baltimore City Department of Public Works last week updated its estimate of the amount of sewage that leaked into the Patapsco River on Oct. 3 from 379,000 gallons to 1.7 million.

The department alleges the leak was from damage to a sewer main caused by a Baltimore Gas and Electric contractor. BGE responded by accusing the department's crews of causing the leak.

More: *Baltimore Fishbowl*

MASSACHUSETTS

Healey Sues Competitive Supplier for Deceptive Practices

Attorney General Maura Healey last week filed a lawsuit in Suffolk Superior Court against competitive electricity supplier Starion Energy and several affiliated telemarketing companies for alleged misleading and deceptive marketing tactics.

The suit alleges the companies broke state law by using unsolicited marketing and digital phone calls promising lower electricity rates, only to charge them more than standard offer service.

"We allege Starion Energy extorted millions of dollars from Massachusetts customers by falsely promising them big savings on their electricity bills, while overcharging them month after month," Healey said. "This case is another example of why my office is seeking to stop these companies from continuing to cheat residential customers in Massachusetts."

More: *Cape Cod Today*

MINNESOTA

PUC Holds Hearing on Nemadji Gas Plant

The Public Utilities Commission last week held a hearing in Duluth to gather company and state officials' input on Minnesota Power's proposed 550-MW natural gas plant in Superior.

The Nemadji Trail Energy Center would cost $700 million. The commission was expected to vote on the project after the hearing, necessary to determine need and public interest, but a last-minute request by Environmental Quality Board for an environmental review pushed back the decision toward the end of the month.

Environmental advocates at the hearing told the commission that there are cleaner alternatives to the plant, and that it is not necessary to help Minnesota Power reach its renewable energy goal, as the utility argued.

More: *Duluth News Tribune*

NORTH DAKOTA

County Assumes Permitting Authority on Wind Farm from Town

PE PURE ENERGY

The Burleigh County Commission last week agreed to assume Morton Township's permitting authority on a proposed wind farm to avoid conflicts of interest.

All three of Morton's supervisors are participating landowners in the 300-MW Altenbruch II project proposed by Pure New Energy USA.

"It's a very clear conflict of interest from a monetary standpoint," a company representative said. The supervisors "will stand to make a lot of money from all of the turbines in the project, not just the turbines on their own property. Without this transfer, the project for Morton Township would have no clear path forward to obtain its permit."

More: *The Bismarck Tribune*

WASHINGTON

State Agencies to Buy Renewable Power Next Year

Eight state agencies, including the Transportation and Corrections departments, will begin getting one-fourth of their power from in-state renewable sources next year.

The agencies will purchase the power through programs offered by Puget Sound Energy and Avista.

More: *The Associated Press*

WISCONSIN

ATC Proposes 131-kV Tx Project to Serve Epic Campus

Epic

American Transmission Co. last week filed an application with the Public Service Commission to build a $21 million, 131-kV transmission project to serve medical software company Epic Systems' campus in Verona.

The project would consist of a substation and a 1.3-mile underground HVDC line that would connect to an existing substation just outside Madison. Epic anticipates its 15.5-MW peak demand to nearly double over the next decade, and it wants the line to serve as a backup in case its primary sources of power fail.

Epic would pay up to $10.3 million for the project, with the rest being covered by ratepayers.

More: *Madison.com* ■