RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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Xcel Pulls out of Mountain West, Endangering SPP Integration

By Tom Kleckner

Xcel Energy, the Mountain West Transmission Group's largest member, said late Friday that it is withdrawing from the Rocky Mountain group and its efforts to join SPP — potentially dooming the planned integration.

Executive Vice President David Eves, group president for Xcel's utilities, said in a press release that the company recently completed a review of the Mountain West's proposal to join SPP and determined that "continued engagement in Mountain West is not in the best of interests of our customers or the company."

Xcel said "limited benefits" for the company's Colorado customers, a lack of "market expansion opportunities" for the Mountain West and increasing "uncertainty over the costs of the RTO" led to its decision.

The Mountain West entities sit in the Western Interconnection, which has seen several market-related developments in recent months. CAISO is pressing the California State Legislature to allow it to become an RTO and is planning to add a day-ahead market to its Energy Imbalance Market. In addition, Peak Reliability and PJM are offering market services through a joint effort called PJM Connext. (See *Multiple Entities, Markets Now Beckon in West*.)

Friday's announcement caught SPP and Mountain West off guard. Xcel spent much of Friday alerting Mountain West members, state and federal regulators and other interested parties before issuing the release.

In an emailed statement, SPP CEO Nick Brown said the RTO was "surprised and disappointed."

"SPP has spent significant time and effort attempting to bring organized wholesale markets and their many benefits to the West," Brown said. "We're hopeful there will still be opportunities to do so."

Brown addressed the issue at the Regional State Committee meeting in Kansas City on Monday. "Obviously, we were shocked Friday by the announcement of [Xcel] pulling out of the Mountain West initiative," he said. "In my initial discussions with other participants of Mountain West, they're meeting to determine what their next steps are, and we will certainly do the same."

Members of the RSC, which comprises regulators from most of the 14 states in SPP's footprint, have also expressed reservations about the integration's cost allocations. (See *Mountain West, Cost Allocation*

Continued on page 29

Ready to Act on DERs, FERC Tells Congress

By Rich Heidorn Jr.

WASHINGTON — FERC told Congress last week it is ready to act on distributed energy resources following a technical conference earlier this month, assuring House members they will not encroach on state jurisdiction.

During a hearing before the House Energy Subcommittee on April 17, commissioners said the April 10-11 technical conference on DERs had helped them answer the questions that had led them to delay action on distributed resources when they issued Order 841 on energy storage in February. (See *FERC Rules to Boost Storage Role in Markets*.)

Commissioner Richard Glick cited questions about DERs' reliability and how the commission interacts with states on aggregation. "I think we got enough information [at the technical conference], in my opinion, to address the issue," he said in response to a question from Rep. Kathy Castor (D-Fla.). (See *Gatekeeper or Facilitator? FERC Panels Debate EDCs' DER Role*.)

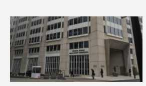
FERC Chairman Kevin McIntyre agreed, saying "the record we are assembling in that process will enable us to take steps comparable [to the commission's action on storage]. I'm not saying that to forecast a particular outcome. I'm just saying that

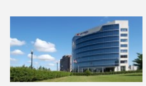
Continued on page 42

More FERC News

Coast-to-Coast Coverage

Also in this issue:





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IN THIS WEEK'S ISSUE

Correction

A photo caption in last week's *RTO Insider* misidentified two speakers at Bloomberg New Energy Finance's Future of Energy Summit. In the photo above, Conor McKenna, managing director at investment bank CohnReznick Capital (left), speaks with Rob Threlkeld, General Motors' global manager for renewable energy. Threlkeld's name was also misspelled in the caption as "Threlked."

Energy Storage Association Annual Conference

Overheard

The crowd at the Energy Storage Association's annual conference in Boston last week. | © RTO Insider

BOSTON — Energy storage deployment will likely grow to 35 GW by 2025 as consumers, businesses and government agencies increasingly support the technology, industry experts said last week.

"Our industry created the momentum for the unanimous support to unleash the benefits of storage through FERC Order 841," Energy Storage Association CEO **Kelly Speakes-Backman** said at her organization's 28th annual conference. "This is a watershed moment, friends, this is our moment." (See FERC Rules to Boost Storage Role in Markets.)

The industry's growth will create hundreds of thousands of jobs, result in $4 billion in cumulative operational savings and avoid 3.6 million metric tons of CO_2 emissions and 1,000 metric tons of CO_2 equivalents, including nitrogen and sulfur oxide, Speakes-Backman said.

"On a regular basis, our teams are in contact with ISOs and RTOs who are seeking guidance in how to create markets and support rules that enable more storage on the transmission level, distribution level, in businesses and in homes," she said.

Clean Peak Shaving

Massachusetts Gov. **Charlie Baker** opened the conference April 18 by saying that energy storage's ability to shave peak demand "may be greater than anything else."

Baker mentioned the "very unusual winter here in New England and in Massachusetts ... where we had subzero temperatures for almost two weeks," during which the region's generators burned through nearly 2 million barrels of oil, more than twice the amount used during all of 2016. (See *Van Welie: ISO-NE in 'Race' to Replace Retirements*.)

"If you push storage all the way ... you could be in a situation where you store during off-peak so that when you have a period like that, you've got enough capacity available to draw the storage and you don't have to pay those huge prices during peak; you don't have to use those far dirtier sources of energy," Baker said.

The Baker administration filed legislation in March to spend more than $1.4 billion on climate change measures, including proposing a Clean Peak Standard mandating that utilities use a minimum level of clean energy to supply the highest-priced peak hours, or 10% of grid hours each year.

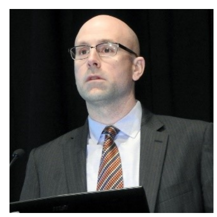
Baker on Wednesday highlighted the state's "combo platter" of ambitious goals to solicit 9.45 TWh per year of hydro and Class I renewables (wind, solar or energy storage) and to develop 1,600 MW of offshore wind by 2030, with contracts for the former due later this month, about the same time the state plans to announce its offshore wind selection.

The scheduling conflict overtaxed the Department of Energy Resources, delaying the offshore selection until later this spring, Baker said.

The state in December awarded nearly $20 million in grants for 26 energy storage projects as part of its Energy Storage Initiative and Advancing Commonwealth Energy Storage program, funded by the DOER through alternative compliance payments and administered by the Massachusetts Clean Energy Center.

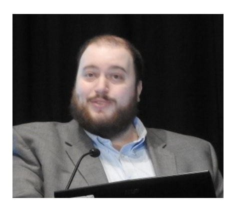
The storage projects are also drawing an additional $32 million in matching funds pledged by developers or host municipalities, "which in my view is always the right way for us to be investing in this stuff," Baker said. (See *Massachusetts Awards $20M in Energy Storage Grants*.)

Commercially Viable



ISO-NE had no storage in its interconnection queue a couple years ago. It now has more than 500 MW of grid-scale energy storage proposals in the queue, a number that has been growing even in recent weeks, said **Christopher Parent**, the RTO's director of market development.

"I think that speaks highly both to state policy in the region driving interest in storage," Parent said, "but also to the fact that storage itself is becoming a more commercially viable product and can actually participate in the market, potentially on a merchant basis as its costs continue to decline."



Dan Finn-Foley, senior energy storage analyst for GTM Research, said "energy storage costs have dropped dramatically over the past few years" and projected the trend to continue. ESA figures show the costs for large-scale storage systems declined by 50% since 2014, and Finn-Foley estimates those costs will drop an additional 35% by 2022.

"Storage's participation in the wholesale

Continued on page 4

Energy Storage Association Annual Conference

Overheard

Continued from page 3

market depends on size, location and function — what they want to do," Parent said.

He noted the RTO is applying the same market cost allocation exemptions to storage that are applied to pumped hydro — uplift charges, for example — and for the same reasons: the reliability services they provide to the grid.

Galen Nelson, senior director for innovation and industry support at the Massachusetts Clean Energy Center, said, "I think it's interesting to note that two out of three offshore wind applicants included storage in their 83-C proposals, so that community is seeing storage as a key asset to improve the economic viability and attractiveness of those proposals."

Finn-Foley said there could be a 20-GW opportunity for storage to replace costly gas-fired peaker plants.

"In California, several natural gas peaking plants that were planned have been either scrapped or they're being re-examined, with energy storage potential taking over there," Finn-Foley said. "In addition, in Arizona they're putting a moratorium on new natural gas plants, focusing on energy storage instead."

Unique Storage

Storage is unique in many ways because it can participate in markets on so many different levels, Parent said.

"Eventually you could put storage behind commercial very easily and I think that's where it becomes unique, because if someone comes to me and says, 'I have this great storage project, I want to participate in your markets,' [the] first question I ask is: 'What is your project?'" he said.

The RTO must first understand how a project wants to participate, which is a function of its size, location and purpose, Parent said.

"Some project developers come to us and they don't even want to participate in the markets, they just want to understand how to interconnect," Parent said. "They're focused on demand charge savings."

Asked about how the RTO treats solar facilities with storage capabilities, Parent said its prefers to directly meter solar.

For smaller applications, "we feel we get a much more efficient outcome by modeling those facilities discretely, so we're dispatching and taking full advantage of the capability of the battery, and also in effect letting the solar participate in the market based on its physical characteristics," Parent said.

"What we see is when we start bundling facilities together, our ability to efficiently dispatch that facility and count ancillary services on it actually starts to disappear," he said.

— Michael Kuser

Current Issues Conference

Resilience, Storms, Survival are Topics at New Mexico Forum

By Jason Fordney

New Mexico State University's Center for Public Utilities held the Current Issues Forum at the El Dorado Hotel. | © *RTO Insider*

SANTA FE, N.M. — In an American West city known for its artists, writers and the beauty of its barren desert environment, state regulators and others last week discussed difficult grid reliability issues and the more vicious side of nature.

New Mexico State University's annual Current Issues Conference has a reputation as a more informal gathering than other industry gatherings. A major topic at this year's meeting was the severity of the 2017 hurricane season, in which grid resilience was tested in Texas, Florida and the Caribbean.

Industry consultant Alison Silverstein told the forum that the duration, magnitude and "customer survivability" of electricity outages are metrics that could be used to measure grid resilience. The grid is operated for the benefit of customers, she said, and resilience should be measured in "customer-based" terms.

Silverstein was an author of the Department of Energy grid study released last August but later criticized the department when Energy Secretary Rick Perry used its findings in his proposal that FERC order price supports for coal and nuclear generators with onsite fuel. (See *Author of DOE Grid Study Disputes Recommendations*.)

Perry's Notice of Proposed Rulemaking was rejected in January by FERC, which instead opened a new resilience docket.

Silverstein told the forum that the technical conclusions she reached did not align with the department's contention in the NOPR that coal and nuclear plant retirements were a reliability threat. "They apparently didn't read the results of their own study," she said.

Regulators shouldn't overly focus on generation-based outages because 90% of outages occur in the distribution system, Silverstein said, and big weather events don't usually affect power plants. Fewer than one in 10,000 customer outage minutes were caused by generation shortfalls.

Coal plants forced to retire since 2002 were old, inefficient and lacked the flexibility that today's grid needs, Silverstein said. "Regulations were not the cause of the retirements," she said, adding that fuel diversity has improved in areas where coal plants have retired.

Coal and nuclear subsidies are not the answer and would "cost a fortune," she added.

There are many ways to improve resilience and reliability, she said, mentioning many of the topics discussed throughout the two days of the forum: distribution system improvements, situational awareness, emergency drills, system recovery and black start capabilities.

"Customer survivability" includes things like backup generators, rooftop solar and emergency supplies like flashlights. "You are already doing a lot of these measures," Silverstein told the regulators.

Hurricane Response Ongoing, DOE Official Says

DOE Deputy Assistant Secretary Devon Streit discussed the department's response to the hurricanes and natural disasters of 2017, an effort that is still ongoing. She said the department had response efforts in Texas, Florida, Puerto Rico and the U.S. Virgin Islands.

"We learned that island response is tough," she said, mentioning not only the difficulties of restoring electric infrastructure in a remote environment but also the challenges of operating without facilities like radar, without which planes cannot land. Ships could not transport electrical equipment because they were carrying food, medicine and other critical supplies.

DOE's Office of Infrastructure Security and Energy Restoration (ISDER) is responsible for energy sector preparedness and response, including electricity, oil and gas, and cybersecurity. It studies threats and examines hazards as well as holding exercises. It is responsible for communicating with federal and state agencies on what is happening on a near-hourly basis, she said in a presentation.

"We are still active for Hurricane Maria," a response now in its 236th day, she said.

Streit discussed the value of situational awareness and mutual assistance projects, such as utilities sharing equipment. "What happened in Puerto Rico or Virgin Islands could happen in other places," she said.

Texas Official Discusses Harvey Response

Public Utility Commission of Texas Chairman DeAnn Walker described how she went to her commission's State Operations Center to conduct the response during Hurricane Harvey, which she said was "a very, very different storm than previous storms such as Ike and Rita."

Walker said that in the first time in her experience, mobile substations were brought in because "we had substations flood that had never taken on water the whole time they were built."

At the operations center, the PUCT worked on grid restoration with utilities and state and federal officials, including DOE, the U.S. Army Corps of Engineers, the Federal Emergency Management Agency and the Department of Homeland Security.

Harvey was the largest rain event in U.S. history, dumping an estimated 40 to 60 inches of water in southeast Texas and southwest Louisiana. ERCOT lost 12,000 MW of generation as gas-fired plants were evacuated or flooded, and coal plants and wind turbines were shut down. (See *Weeks Later, Utility Officials Still Awed by Scale of Hurricane Harvey*.)

Spring 2018 Joint CREPC-WIRAB Meeting

RTOs Take to Catwalk for Western Commissioners

By Robert Mullin

VANCOUVER, Canada — The three RTOs vying to organize Western electricity markets on Thursday faced off before an audience of utility regulators in what one state commissioner billed a "beauty pageant."

"Thank you for competing," Montana Public Service Commission Vice Chairman Travis Kavulla jokingly told representatives of CAISO, SPP and PJM. Kavulla is co-chair of the Committee on Regional Electric Power Cooperation, which hosted the panel at its spring joint meeting with the Western Interconnection Regional Advisory Body in the Coast Coal Harbour Hotel.

The regulators were there to examine the possible benefits and drawbacks of the competing grid operators' efforts to sign up utilities in a region that has been historically resistant to organized markets. (See *Multiple Entities, Markets Now Beckon in the West* and *CAISO Bid for Western RTO to Face Competition in 2018*.) They, and other industry watchers, also learned what region PJM is focusing on in developing its Western market partnership with Peak Reliability.

Here's some of what they heard.

Looking West

Little Rock, Ark.-based SPP has been running its Integrated Marketplace since 2014, after previously operating a balancing system like CAISO's Western Energy Imbalance Market (EIM). The RTO last year entered membership negotiations with Mountain West Transmission Group, a partnership of seven transmission-owning entities within the Rocky Mountain region of the Western Interconnection. The effort hit a significant roadblock late Friday when Xcel Energy announced it was pulling out of the group and the negotiations with SPP because of the "limited benefits" for its customers in integrating into the RTO. (See *Xcel Pulls out of Mountain West, Endangering SPP Integration*.)


Carl Monroe
Southwest Power Pool

"There are benefits from operating together" in an RTO, SPP Chief Operating Officer **Carl Monroe** told Western commissioners. "A natural inclination we would have is to look west."

"We've got another unique situation in that we're the only one connected to ERCOT," he said.

Monroe touted the fact that SPP's Board of Directors cannot express a decision without the consent of the RTO's Members Committee, which provides each market participant a vote over market initiatives presented to the RTO board.

He also pointed out that SPP has functioned as a reliability coordinator (RC) for 20 years.

"And how that interfaces with the market … that was one of the key issues we dealt with in the market," Monroe said. "These are hybrid markets. … They have to be designed to protect reliability itself.

"Our job one is to keep the lights on — reliability," he added. "Even the economics don't make sense if you're not reliable."

SPP's market has been efficient for its members, he said.

"The capital costs of putting the market in — we recovered those within six months," Monroe said, adding that the SPP footprint today carries 5 GW less generation than it would "if we weren't running the market."

He also pointed to SPP's expertise in integrating large volumes of renewables.

"Of course we're in a wind-rich area. We just set a record when 63% of the load was served by wind," he said. "That could not have been done unless on a regional basis."

"We actually do interregional coordination," Monroe continued. "This is one of the things we'll need to do within the West itself, is making sure we coordinate all the activities, whether it's transmission planning, transmission operations, reliability coordination, market activity. All those things will have to be coordinated with the other parties that border whatever footprint we finally get around to.

"Part of the strategy going forward is being open to those parties who want us to do these services for them," Monroe said.

Listening to the West

"As you all know, many states in the West are aggressively pursuing more renewables," CAISO CEO **Steve Berberich** said.

With a fleet heavy in renewables, ramping and overgeneration become "a focal point" for the ISO, he said.

"Security-constrained economic dispatch — in other words, an optimized market — is the best way to run the grid as efficiently as possible, and the sharing of resources is the best way to solve our critical need collectively to support the variability of renewables and the induced ramps," Berberich said. "Further, the zero-marginal-cost power is better shared at a lower cost for all of our customers. We share this view with our [SPP] friends from Little Rock. You'll also hear that from our friends from PJM in Philadelphia."

Berberich trumpeted the EIM's $250 million in member net benefits since it was launched in 2014. CAISO last year proposed to expand the EIM to include day-ahead transactions without transitioning the market into a full RTO. The ISO has also announced it will withdraw from Peak Reliability as an RC and provide reliability services to other balancing authority areas in the West.

He acknowledged that the EIM's implementation of a day-ahead market will require the ISO to resolve approaches to resource adequacy and transmission compensation.

"Those are solvable, and we'll continue to give deference to state control over resource mix and capacity margins. We also expect the EIM Governing Body to morph into a broader governing body with at least some joint decisional authority with the current [CAISO] board of directors," he said.

CAISO expects to offer the combined EIM and day-ahead market at a cost significantly below the ISO's current grid management charge, Berberich said. It also intends to offer the same reliability services as Peak at a "significantly reduced" cost.

"When you cut through it all, the fundamental markets are all the same. … What is different in our market, however, is the sophistication of our optimization and how it supports renewables, steep ramps and

Continued on page 7

Spring 2018 Joint CREPC-WIRAB Meeting

Western Regulators Get Schooled in RTO Legal 101

By Robert Mullin

VANCOUVER, Canada — With three RTOs advancing competing efforts to extend their services into the West, the region's utility regulators last week took a timely crash course on the legal implications of allowing their utilities to join organized markets.

It was a bracing — and invaluable — session, according to some industry stakeholders attending the spring joint meeting of the Western Interconnection Regional Advisory Body and the Committee on Regional Electric Power Cooperation.

Scott Hempling, an attorney specializing in public utility law, provided a compressed but comprehensive 90-minute primer of the statutes, regulations and case law governing the functioning of RTOs, beginning with their origins in FERC Order 2000, which encouraged — but did not require — utilities to form or join an RTO.

| © RTO Insider

"The primary purpose was to end discrimination by transmission owners," Hempling said. "One of the methods of discrimination before Order 2000 was to keep secret the availability of transmission."

Hempling explained the four "minimum characteristics" of RTOs required by FERC: independence; appropriate scope and regional configuration; operational authority; and exclusive authority over short-term reliability.

In addition, RTOs must fulfill eight "required functions," including tariff design and congestion management. "Understanding those 12 things is crucial to understanding what's getting turned over to the RTO," he said.

Hempling clarified that a transmission-owning utility legally becomes a customer of an RTO once it joins the RTO and turns over its transmission assets. It also becomes FERC jurisdictional. "When your utility joins an RTO, it no longer provides transmission service," he said.

"Let me put it bluntly: you lose jurisdiction over transmission costs" when a utility joins an RTO, Hempling told the audience of commissioners. As a result, any state commission that has approved RTO membership cannot "logically disallow" a utility from including in retail rates the costs of becoming a customer of the RTO.

"Once FERC determines that the rate charged by the RTO to the transmission

Continued on page 9

RTOs Take to Catwalk for Western Commissioners

Continued from page 6

distributed generation aggregations," Berberich said.

He said the ISO doesn't foresee the need for any new transmission to "support the transformation into a regional market."

On the issue of governance of an expanded ISO, Berberich told the commissioners that the "main pathway" is to change the existing governance model through legislation at the state level in California.

"The alternate pathway is to continue to evolve our governance according to the Energy Imbalance Market's governing model, and with a day-ahead market, that will necessarily involve decisions on transmission compensation and some form of resource adequacy, both potentially having input from the [EIM] Body of State Regulators," he said.

"Some of the ISO brethren say the Peak/PJM market offering is a market by the West, for the West, which misses what has already occurred in the Energy Imbalance Market. Participants are certainly not guests of the ISO, rather, they help form the market," Berberich said.

The ISO's job is to "listen to whatever the West wants and do our best to provide the value inherent in our interconnected systems."

"When do we need to move to this new market? Soon, we think. We believe it will provide the most efficient way to streamline new transmission planning and upgrades, reduce the need for more capacity and reduce the need to curtail valuable clean resources. It provides the greatest value with the geographical and resource diversity that the West is blessed to have."

For the West, by the West

"We believe there's a very real opportunity for the utilities in the West to pursue the potential for the creation of a separate market," said **Stu Bresler**, PJM senior vice president of markets and operations.

Bresler was speaking on behalf of the joint proposal between Peak Reliability and PJM Connext (a PJM subsidiary) to develop new wholesale market structures for the West. Like the CAISO EIM day-ahead expansion, it would fall short of creating a full RTO in the near term, while creating a foundation for one in the future.

Kavulla asked: "What area are you focusing on? Is it an area with lots of trees and hydro, or lots of sun?"

"We're focusing primarily in the Southwest," Bresler replied.

"The value proposition — and Steve has already said it before I had a chance to get up here — is a market for the West and by the West," Bresler said. "What we are really leveraging here is the combined knowledge of our expertise of both of our organizations.

"PJM has proven its ability to promptly deliver on its commitments," he said, citing PJM's pledge to complete a business plan

Continued on page 8

Spring 2018 Joint CREPC-WIRAB Meeting

RTOs Take to Catwalk for Western Commissioners

Continued from page 7

with Peak by March 30. (See *Peak/PJM Enter Western Market Commitment Phase*.)

"We have also been sharing the full plan with a set of key entities in the Western Interconnection that could potentially form the basis for a separate market out here in the West, should they decide to pursue that," he said.

Striking a similar note to SPP's Monroe, Bresler said that wholesale electricity markets exist for the sole purpose of reinforcing grid reliability.

"That's why we develop them; that's why we operate them."

Bresler said markets are intended "to ensure that physical asset owners have the financial incentive to act in a manner as to reinforce grid reliability." Key to that is ensuring that market prices reflect actual operating conditions, and that "those prices are transparent to market participants in real time."

"And that transparency and that reflection of actual operating conditions is what builds the confidence of the physical asset owners that the dispatch instructions delivered by the system operator are in their financial best interests. That financial best interest is a powerful motivator that supports reliable grid operations," he said.

"We believe that the bulk of trading activity actually occurs in the bilateral markets," Bresler said. "That is really an appropriate way for things to occur because it is what allows market participants to best manage and therefore minimize their risk."

Bresler said the Peak/PJM business plan — which has not been made fully available to the public — shows that "with a large amount of participation in a market in the West, the production cost savings become very substantial."

Lauding Peak's RC capabilities, Bresler said that much of the hard work of starting up a regional market is already complete based on Peak's West-wide model and the processes and mechanisms in place to support reliability.

"Really, the smaller part is layering [the market] on top of those reliable grid operations," he said.

PJM's "Day 1" market offering would consist of a day-ahead and real-time market.

"Some options that could be included as well, should participants want it, we could operate ancillary services. We could also add [financial transmission rights], but that's not a requirement for Day 1," Bresler said.

Based on feedback from potential participants, Bresler said Day 1 won't include a resource adequacy construct or capacity market; consolidation of transmission tariffs; provision of transmission service; and regional or sub-regional transmission planning.

On one key issue, Bresler sought to score points from commissioners overseeing utilities already participating in the Western EIM.

"I don't think of the establishment of the market as being exclusive of participation in the EIM," he said.

Bresler noted that Peak and PJM had envisioned getting a "critical mass" of commitments from market participants by May or June, but they have extended that timeline to determine a "go or no go" decision on the market by the fall.

Kavulla asked Bresler when Peak/PJM anticipated releasing its full business plan for public review.

"We don't really have any plan to do that. If members do decide to take the next step, we would take the decision with the members to do that," Bresler said.

Bresler wrapped up his moment in the spotlight by echoing Berberich's conclusion: "If utilities in the West want a full market … there's not a better time to do it than now."

Spring 2018 Joint CREPC-WIRAB Meeting

Western Regulators Get Schooled in RTO Legal 101

Continued from page 7

owner is prudent, the state must pass that cost on" to customers, Hempling said.

And while a transmission-owning utility does receive a *pro rata* share of the revenues the RTO generates from all transmission customers, the resulting credits don't always make retail ratepayers whole. "You'd think the retail charges and credits would be a wash, but that's not necessarily the case," Hempling said.

One commissioner asked if FERC made distinctions within RTOs between how it treats investor-owned utilities on the one hand and rural cooperatives and municipal power systems on the other.

Hempling noted that the Federal Power Act exempts publicly owned systems from FERC oversight — unless they are TOs and join an RTO. "Co-ops and munis join RTOs by contract. Now if they're transmission owners, are they subject to FERC jurisdiction? The answer is 'yes.'" Based on FERC's reciprocity rule, "if you want to take transmission service and you own transmission, then you're going to need to provide transmission service," Hempling said.

FERC 'Controversies'

Hempling turned to key areas "where FERC finds itself resolving controversies" related to the nation's RTOs.

Chief among the agency's concerns: return on equity for transmission investments.

"There is a great deal of controversy over what is the 'fair return on equity,' and it's not just about profiteering," he said. "We're talking about hundreds of billions of dollars in necessary transmission investment, and that money is going to have to come from somewhere and get paid off over a certain period of time. So return on equity matters, both from the customer standpoint and the investor standpoint."

Hempling pointed to the differences between administering general rate cases (FERC's past approach) and formula rate cases (its current approach).

"A formula rate's a spreadsheet, and I guess the word is that you 'populate' the spreadsheet with the numbers — as opposed to a

Scott Hempling | © *RTO Insider*

general rate case, where everybody and their brother and father and mother and sister gets into the case and everybody fights over what the ultimate [regulated rate of return] should be," Hempling said. "For years, FERC set transmission rates with a general rate case, but now it prefers to set them by formula. But just because it's a spreadsheet that you populate across doesn't mean that FERC goes to sleep and just asks that you include whatever you want to put in there."

Hempling expressed his respect for FERC, calling the agency "very, very professional — even in the current political environment." But he cautioned state commissioners about the agency's limitations in judging the reasonableness of transmission project expenditures, another area of focus for the agency.

FERC "does not disallow costs very often. … There is a question whether an agency whose authority is transmission [has] competency in looking at alternatives," he said, adding that FERC "does not do integrated resource planning."

Hempling also pointed to FERC's role in overseeing RTO transmission cost allocation.

"You're a multistate region — which state's customers are paying for what? And there are now a variety of court of appeals decisions and FERC decisions that allocate costs among the family members, who at conferences like this are all happy to see each other over pastries, but then they're happy to hire very expensive lawyers to fight over who's getting which dollars."

Power to the States?

Hempling posed a series of hypothetical questions regarding a state's influence over utilities before and after a decision to join an RTO. His answers, he made clear, were based on his own professional opinion, not settled law.

Can a state order its utility to join an RTO?

Yes, Hempling said. A state commission could find that a utility's rates "will not be just and reasonable, reliability will be insufficient to satisfy state law unless the utility joins an RTO," he said. "I also think therefore — and everything I'm saying now is subject to debate — that a state can reject a utility's request to join, I think for the same reason."

Can FERC order a utility to join?

"This question, along with all the others, is untested, because if FERC does have the authority to order a utility to join, then that would pre-empt a state that rejects a utility to join. That would be an inconsistency, right? You can't put a utility between a rock and a hard place," Hempling said.

"Do I think FERC has the authority to order a utility to join? I think they do. … And in any event, FERC has never said so," he said. "And that's why the joining of RTOs by utilities is opportunistic. That's why they at least get to decide … based on their own self-interest, because FERC has not said it can order a utility to join." But FERC has conditioned a utility's request for merger approval on joining an RTO, he noted.

Hempling also posed the possibility of a state requiring a utility to get state permission before proposing to the RTO any new construction of transmission above a particular level. "In my legal opinion, a state can do that, but it has not been tested," he said.

After the Fact

How can a state pursue its values after a utility joins an RTO?

Hempling noted that legal precedent precludes states from forcing a utility — includ-

Continued on page 10

Spring 2018 Joint CREPC-WIRAB Meeting

Western Regulators Get Schooled in RTO Legal 101

Continued from page 9

ing an RTO — to submit a tariff change with FERC. Still, a state can circumvent that restriction by persuading the utility or RTO to make a state-sought filing.

"The way the Federal Power Act works is this: If a utility makes a filing at FERC, and that filing satisfies the Federal Power Act standard of 'just and reasonable' ... FERC is obligated to approve it, even if FERC has a better idea. ... It's a utility-deferential statute," he said. "Which means if you are a state wanting to say, 'I've got a better idea,' and so you introduce at FERC a filing, FERC is going to say, 'I like your idea a lot better, state, but the utility's idea is just and reasonable.'"

SPP has worked around this situation through the authority granted to its Regional State Committee, which can order SPP to make a filing even if the RTO disagrees with it, Hempling said. "Now SPP can also make its own filing, and they can say, 'We think the state's idea is crap,' but we file it because we agreed to file it. And what happens now is that FERC can actually choose either one. So it puts the states on equal legal footing in terms of the chances of being selected."

Former California Public Utilities Commissioner Mike Florio, now principal of Florio Consulting, said that California legislators have asked him whether the state can direct an investor-owned utility to leave an RTO.

"My ... answer is no, because ... it's a contract that FERC has approved," Hempling replied. "And that contract is where you go to find out the authority of someone to leave. And because it's a FERC-jurisdictional contract, a state cannot issue an order that causes a utility to act in violation of the contract. That would be pre-emptive.

"FERC wants the stability about decisions to be in FERC's hands," he added.

Utah Public Service Commissioner David Clark said one of his concerns about his state's utilities joining an RTO is the cost-of-service differential between it and other states in the region — namely, California.

"I know FERC has been concerned that the RTO process maintain status quo benefits and focus on new benefits," Hempling said. "I think FERC has not had the notion of creating enemies of the RTO process."

Another commissioner asked: "How do we know we're protecting our state's interests?"

Hempling replied with a question: "What is the commonality that we're trying to pursue through the RTO mechanism when there are so many differences? ... Focus on what the commonalities are.

"I was once at a [National Association of Regulatory Utility Commissioners] meeting and there was a Midwestern commissioner who said, 'Whoa, if we're not preserving state regulation, what are we here for?'" Hempling said. "And I'm thinking, 'What you're here for is something bigger than that. You're here for efficiencies; you're here for the customer; you're here for investors; you're here for marginal values. You're here for something. You're not here for jurisdiction.'

"The mission is not jurisdictional preservation. It's jurisdictional effectiveness."

GCPA Spring Conference

RTO CEOs Trade Quips, Thoughts on Future

By Tom Kleckner

Four CEOs: MISO's John Bear, SPP's Nick Brown, PJM's Andy Ott and ERCOT's Bill Magness | *© RTO Insider*

HOUSTON — At the Gulf Coast Power Association's annual spring conference last week, ERCOT CEO Bill Magness once again moderated a panel of his counterparts from around the country, welcoming back MISO's John Bear and SPP's Nick Brown. Joining the discussion this year was PJM's Andy Ott, with a vacant chair left to recognize 2017 participant Steve Berberich of CAISO.

Magness asked Brown and Ott to explain their participation in the Western markets. SPP has been working to integrate the Mountain West Transmission Group since January 2017, while PJM has partnered with Peak Reliability to offer market services in the Western Interconnection through its PJM Connext subsidiary.

Brown pointed out that SPP is not a greenhorn when it comes to being active in the region. "We've worked with participants in the West the last 10 years, helping them to understand our markets," he said. "The efficiencies, the increasing of reliable operations across larger areas, the integration of renewables … those are all things people are wanting."

"It's really education, trying to fill a void," Ott said. "We're fostering a discussion of competitive markets. Even if we're not successful, we've had a positive influence. When we first got out there, we saw cultural differences, but we very quickly talked about a market for the West, by the West. We let them realize, 'Wait a minute, I've got control,' because it's their assets, their region."

In describing the value of RTOs to their members, Brown shared a story about a conversation he had with a current SPP participant, who had previously formed another organization consisting of member utilities.

> ***"We're fostering a discussion of competitive markets. Even if we're not successful, we've had a positive influence."***
>
> **Andy Ott, PJM**

The member asked Brown, "'What are you going to say to convince me to turn over management of my assets?'

"'Well, how did you do it within your organization?'" Brown said he responded.

"'I pried it out of their cold, dead fingers.'

"I said, 'OK, we can't do that. We're not going to do that. We've got to show the value proposition [of an RTO]. Quite frankly, that's why you don't have value in doing this by yourself anymore.' That's what the folks in all our footprints saw: the benefits."

Asked what he was watching in the other RTOs, Bear pointed first to their response to FERC's resilience initiative, saying "there are ways we could be more resilient."

"The FirstEnergy situation in PJM … we're interested to see how that gets dealt with," Bear said, referring to FirstEnergy Solutions' recent bankruptcy filing and plea for governmental protection of its nuclear and coal plants. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

"We're also watching Andy's guys to see how they do scarcity pricing. For SPP, we're watching how they deal with all that wind, and how they do so well with 50%, 60% [wind penetration] levels. We can only simulate that."

"My neighbors matter a lot to me. John and I are intertwined, and we have great working relationships between the two of us," Ott said, noting his organization also learns from SPP. "A developing story is in New England, where they worry about fuel security. They only have a couple of interstate pipelines, and we have 25. How they deal with that fuel-security problem will affect us."

Like SPP, MISO is also working to accommodate a large influx of wind energy and other renewables. Bear said the ISO had 100 MW of renewable energy in the mid-2000s, but that has now grown to 18.5 MW.

"We had people telling us that with up to 5 GW [of renewables], we would crash the system," he said. "We've done a lot of transmission build to disperse that [energy] and pass the benefits around. We've also had to design products to handle the wind. We had a lot of wind turbines that wouldn't turn down, but now, we incentivize them to do the right things."

Magness did not let the round table end without uttering a word he said is heard these days at every self-respecting conference: blockchain.

"There, I said it!" he said, peering at his audience.

Later, upon begin congratulated for mentioning "blockchain," Magness brought up another futuristic word from a bygone era: "Plastics!"

GCPA Spring Conference

Baker's Carbon Dividends Plan Reaches Across Aisle

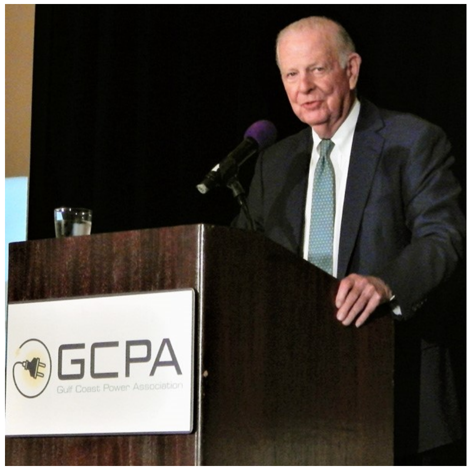
By Tom Kleckner

HOUSTON — Approaching his 89th birthday, James A. Baker III last week revealed the enduring sharpness of his political mind with a keynote address that delved into personal history, decried the "bankruptcy of our national public debate" and offered a middle ground to address climate change.

Baker made his name in Republican politics, running campaigns for Gerald Ford and George H.W. Bush. He ran the White House staffs for both Ronald Reagan and Bush and served as their secretary of the treasury and state, respectively.

Last year, Baker partnered with George Schultz, Hank Paulson and several other luminaries in promoting the "Carbon Dividends" plan, a "new climate strategy" that purports to strengthen the American economy, reduce regulation, help working-class Americans, shrink government and promote national security.

"At the risk of tooting my own horn, I do know a little bit about politics," Baker said. "It's obvious to me this solution should be able to attract support from those on both sides of our political debate."



James A. Baker III | © *RTO Insider*

The plan rests on four pillars: a gradually increasing carbon tax; carbon dividends for all Americans; border carbon adjustments; and significant regulatory rollback.

Baker and his coauthors propose to begin with a "sensible" $40/ton carbon tax that would steadily increase over time. "Every dime" of the proceeds would be returned to citizens, giving the theoretical family of four $2,000 in carbon dividend payments in the first year.

"In my view, that would not be a true tax," Baker said. "The plan speaks to the frequent frustration about economic insecurity expressed by most Americans. These measures, to be viable, have to take into account the impact of economic growth to human welfare.

"They must be politically sustainable," he said, emphasizing the importance of that point. "Make no mistake, politics is about gaining and exercising power. That's why political parties exist. That's why we have campaigns and elections. Power should be a means to implement policies that advance freedom, security and the well-being of our citizens."

Baker said he recently took a call from former Secretary of State John Kerry, "who said he might be able to sign on to [the plan] too."

"The moment may never be more right," Baker said. "If we spend too much time debating the role of climate change, we may find ourselves rehashing the same political arguments that have poisoned our debate. Our plan can be seen as a really good mainstream policy, just in case the Al Gores of the world happen to be right."

Overheard

HOUSTON — The Gulf Coast Power Association's annual spring conference drew almost 400 attendees to the so-called Energy Capital of the World to participate in discussions on retail markets, distributed generation and competitive transmission.

'New-day Democrat' Houston Mayor Recalls Legislative Career

Houston Mayor **Sylvester Turner**, a Democrat, broke character as he reprised his role in Texas Senate Bill 7, which deregulated the state's electric industry in 1999 and set up a fund to help low-income consumers.

"I remember my sparring partner [Dallas Republican Steve Wolens] asking me whether Democrats would support deregulation. We'll deregulate anything," he said, as the ballroom erupted in laughter.

Smiling sheepishly, Turner regained his poise. "We are new-day Democrats!"

It turns out that Turner, a 27-year member of the Texas House of Representatives, was a new-day Democrat back in the 1990s. "I said, 'I'm not opposed to deregulation, especially if it will spur technology and innovation and new ways of doing things.'"

Turner's only request was the creation of the System Benefit Fund, which collected about $800 million in fees from customer bills. While the Legislature did use the fund to help the state's budgets meet the legal definition of balanced, Turner was able to ensure the fund disbursed the remainder to low-income customers in its final three years of existence, he said. The fund was wound down in 2017.

"This doesn't mean elderly, low-income consumers don't exist," Turner said. "They're still there, and the need is still there. I hope we will always be sensitive to those that are vulnerable."

Industry Analysts: Expect Low Prices in SPP

A pair of industry analysts agreed that SPP will "by far" be offering lower wholesale prices than any other RTO over the next five years.

"There are a couple of things in SPP that will be coming down the pipeline in the next couple of years," said **Brian McIntosh**, product director at Genscape. "With Mountain West [Transmission Group]'s integration, you will have a ton of hydro and baseload generation that would be added into SPP with a limited load. You'll be adding more supply to the system with more wind growth."

Continued on page 13

GCPA Spring Conference

Market Monitors Debate Roles, Effectiveness of Programs

By Tom Kleckner

HOUSTON — Market monitors from the Eastern Interconnection and ERCOT last week debated their roles in the RTOs they oversee and the need for effective monitoring programs at the Gulf Coast Power Association's annual spring conference.

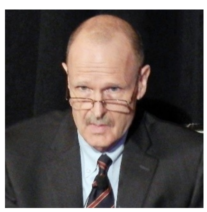
"Part of our role is to dig into the garbage and the bad side of things," **Keith Collins**, executive director of the SPP Market Monitoring Unit, said at the Gulf Coast Power Association's annual spring conference. "Most people would be surprised at what other people are attempting to do. Unfortunately, that gives us the job security that we have."

"We maintain credibility by being credible," said Potomac Economics' Pallas LeeVanSchaick, director of NYISO's MMU. "We've established our reputation by providing information and transparency into the market. When we have opinions, and we have a lot of market suggestions, we back that up with rationale. We're not promoting one set of participants over another."

Pallas LeeVanSchaick (left) and Steve Reedy | © *RTO Insider*

Potomac's Steve Reedy, deputy director of ERCOT's Independent Market Monitor, said his group considers its role to be that of an educator.

"Certainly, we advocate certain positions, but we look to make sure an honest discussion is held on all important issues," Reedy said. "We don't win every battle, and not every issue we advocate passes. But as long as we feel the issue is properly understood by all sides and by the [Public Utility Commission] in its votes — we feel that is our most important role."



"Our primary function is to help support and maintain competitive prices," said Monitoring Analytics President **Joe Bowring**, whose firm serves as PJM's IMM. "We have three sub tasks: looking for instances of market power and reporting on them; making proposals that improve market design; and continuing to support market design changes that support competition."

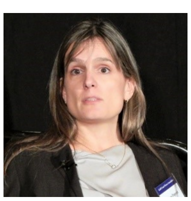
Asked how to keep monitors from being seen as just another stakeholder in the market, Bowring said, "I've been accused of many things. I've been accused of being pro-load, I've been accused of being pro-generation. I've never been accused of being just another stakeholder. We're used to losses in the stakeholder process."

Reedy also addressed the coming summer in Texas, saying he has seen August forward prices of $200/MWh. ERCOT is expecting record peak demand that month, but it only has a 9.3% reserve margin after a wave of coal-fired retirements last fall.

"It's been quite a while since things have been this tight in ERCOT," Reedy said. "It will test the political resolve of certain entities and whether they want to commit to an energy-only market. All indications so far are they want to continue, but that could change with multiple hours of $9,000 prices [per megawatt-hour for scarcity pricing]. From an IMM perspective, it's very interesting to us."

Overheard

Continued from page 12



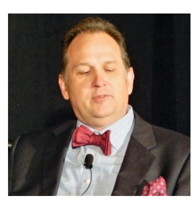
Bojana Popovic, vice president of strategy and product development for EDF Energy Services, agreed, suggesting attendees look at the power purchase agreement prices for wind in SPP. "They still have four years of [production tax credits] … just look at where it's cheapest to contract renewables," she said. "It's SPP.

"I do have a question about how long SPP can sustain low prices and maintain that level of investment."

McIntosh cautioned against placing too much stock on future predictions.

"It looks like a future with super low natural gas prices, but if you think that's the future we'll end up with, you can shoot yourself in the foot."

DG Panelist: You Can't Stop the Technology



Patrick Reinhart, El Paso Electric's assistant vice president of Texas external affairs, told his fellow DG panelists that, "I think a lot more customers are going to want DG on the system. They want storage on system. They want the grid to back them up," he said. "It goes back to who pays for it. For 100-plus years, energy flowed in one direction. Now, it's flowing back the other direction. I'm an opponent of toll roads. We can argue about whether to go in that direction."

Meghan Nutting, vice president of policy and government affairs for solar developer Sunnova, agreed DG is coming. Just don't listen to the naysayers, she said.

"It's interesting to me to see all these discussions happening for a technology with a penetration of 1 to 3%. They say it's a very small part of the system right now," Nutting said. "I think before we try to limit this technology, let's give it a chance for success. And not just solar, but energy efficiency, [electric vehicles], microgrids … rather than limit or stop these things now, let's see what we can do with these technologies."

As an example, she pointed to California, where she said CAISO recently canceled $2.6 billion in transmission projects no longer needed because of the state's abundance of rooftop solar.

"It's important to keep that in mind when talking costs and benefits," Nutting said.

— Tom Kleckner

CAISO NEWS

CAISO Says Changes Will Better Match Forecasting, Demand

By Jason Fordney

CAISO last week provided details on its plans for major changes to improve the alignment of its day-ahead market with real-time demand by introducing more scheduling granularity and other refinements.

Nearly 150 participants joined a conference call Wednesday at which the ISO discussed technical aspects of the revised straw proposal it issued April 13. CAISO has also proposed extending the proposed changes across the Western Energy Imbalance Market (EIM).

As currently proposed, the changes would address forecasting uncertainty in the day-ahead that is currently left to the real-time market to resolve, CAISO Senior Design Policy Developer Megan Poage said during a presentation.

The proposal would introduce 15-minute scheduling in the integrated forward market, which procures the generation needed to meet forecast demand. It would also create a day-ahead imbalance reserve market product and combine the integrated forward market and residual unit commitment. The third major prong in the initiative is to procure imbalance reserves with a must-offer obligation to submit economic bids in the real-time market.

"These three elements are dependent on each other. They must all be introduced at the same time," Poage said, adding that "We'll be moving toward a co-optimized day-ahead market run."

The initiative, which was announced in December, is seen as a possible forerunner for a new Western RTO market structure by introducing a day-ahead market into the EIM, which is currently only a balancing market. (See *CAISO Plan Extends Day-Ahead Market to EIM* and *CAISO Day-ahead Could be Tailored for West*.)

"Grid infrastructure has advanced, the resource fleet has changed and the policies regulating operation of the grid have evolved (i.e. FERC-mandated 15-minute scheduling in real-time energy markets)," the ISO said in the straw proposal.

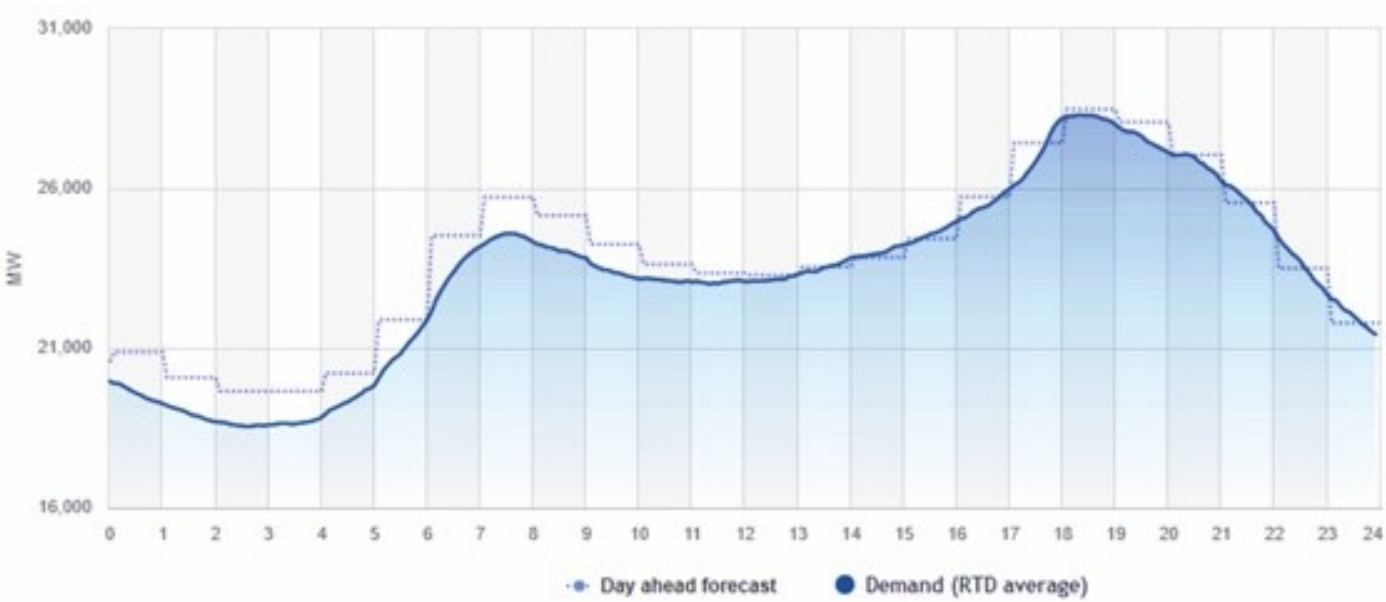
The proposal is intended to help manage excess solar generation in the middle of the day and make it possible to also reduce generation output. The current structure does not allow the ISO to decommit resources that were scheduled in the integrated forward market.

CAISO said the current hourly scheduling structure causes the day-ahead forecast to be higher than actual demand, resulting in "downward uncertainty," in hours 1 to 12, and mismatches between day-ahead forecast and actual demand in hours 20 to 22.

Based on comments from market participants, CAISO changed the proposed 15-minute and five-minute imbalance reserves products in upward and downward directions into a single product for both directions. To address five-minute needs, CAISO would create sub-regions for the imbalance reserves product.

It also provided additional information explaining certain formulas it plans to use in the new day-ahead market, data analysis and proposed methodologies to determine imbalance reserves requirement, as well as a settlement and cost allocation worksheet for use by potential market players.

Overall, CAISO said, the changes will help decarbonize the electric grid, improve reliability as the system changes and create more market benefits across the region. The goal is to present the proposal to the EIM Governing Body in August and the ISO Board of Governors in September.



CAISO says the current hourly scheduling structure causes "downward uncertainty" between day-ahead forecast and real-time demand in hours 1 to 12 and "granularity difference" in hours 20 to 22. | *CAISO*

CAISO News

Calif. Energy Bills Move Forward, but Big Ones Stall

By Jason Fordney

California lawmakers moved forward with several pieces of energy legislation last week, but hotly watched items such as a 100% renewable energy standard and CAISO regionalization seem to be set on simmer.

There has been no movement this year on SB100, former State Senate President Pro Tempore Kevin de Leon's 100% renewable energy bill that was front and center as the 2017 legislative session drew to a close. (See *CAISO Regionalization, 100% Clean Energy Bills Fizzle*.) SB100 has seen no votes since the Assembly Appropriations Committee last September.

And AB813, legislation that would regionalize CAISO, sits in committee during this session as other, higher-profile issues heat up. (See *Calif. Lawmakers Relaunch CAISO Regionalization*.) The regionalization language is currently in the Senate Rules Committee and the next step is a referral to the Energy Committee.

The U.S. Senate Democratic primary between de Leon and longtime Sen. Dianne Feinstein is taking up a great deal of political oxygen and an unrelated series of sexual assault controversies are another major distraction in the Capitol. (See *Harassment Flap Could Hinder Calif. Energy Bills*.) Police brutality accusations and federal immigration policies have brought protests to Sacramento's downtown. Additionally, the financial health of the state's three investor-owned utilities is taking up bandwidth. (See *Wildfire Costs Ignite Worry at CPUC, Legislature*.)

On Thursday, the Assembly Utilities and Energy Committee, chaired by Assemblyman Chris Holden (D) passed several pieces of legislation, including:

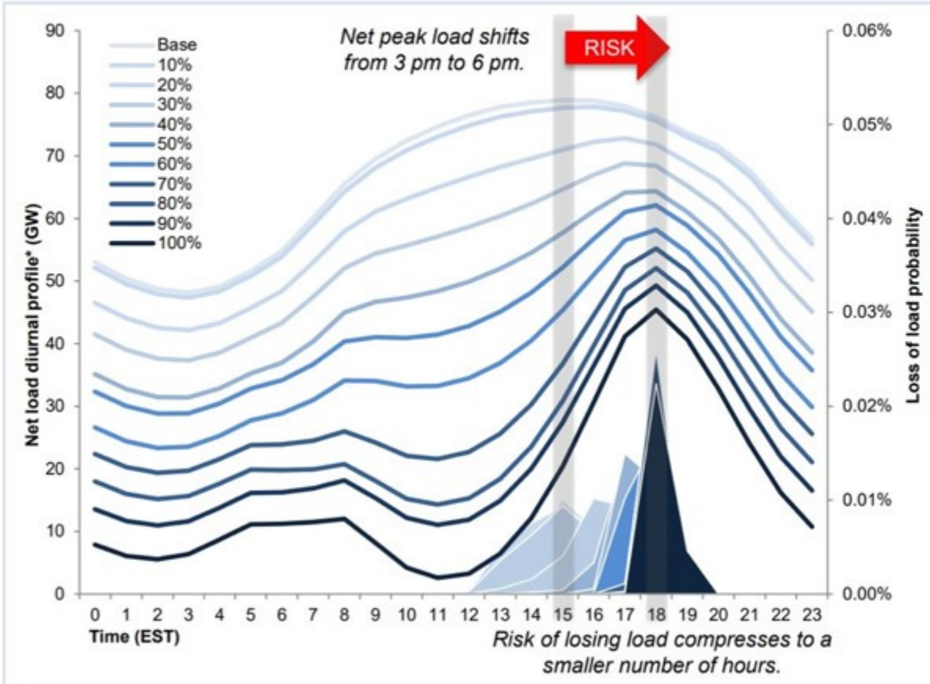
California State Capitol | *© RTO Insider*

- AB2068 (Chu), to Appropriations: It would require IOUs to evaluate the feasibility of discounting rates for public schools by at least 15% and for the California Public Utilities Commission to determine whether to adopt the discount. It requires the CPUC to direct IOUs to evaluate and report on the feasibility and economic impact of establishing the discounts. The evaluation must include commercial rate increases for the past five years that affected schools and the economic impact to other ratepayers if all public schools receive the discount. The bill requires the CPUC to submit the report to the legislature by Jan. 1, 2020.
- AB2208 (Aguiar-Curry) to Natural Resources: The bill requires investor-owned utilities, community choice aggregators, retail energy sellers and publicly owned utilities to procure an unspecified percentage of their resources from geothermal, biogas or biomass facilities. An unspecified amount would have to be procured from the Salton Sea geothermal resource area, 10 generating plants producing 327 MW in Southern California's Imperial Valley. According to an author's statement, "AB 2208 will make it easier to reliably integrate higher amounts of renewable energy generation into the grid by requiring the procurement of 'grid-balancing' renewables, such as geothermal and bioenergy." It would allow bioenergy facilities open to continue accepting wood waste as a forest fire management measure.
- AB2515 (Reyes) to Appropriations: The bill requires the CPUC to report to the legislature pending and previously approved changes to IOU revenue requirements over at least the past five years that resulted from requests by IOUs and CPUC decisions and resolutions. It also requires IOUs seeking a rate change to disclose estimated rate and bill impacts on each customer class.
- AB2831 (Limon) to Appropriations: Requires the CPUC, in consultation with the Office of Small Business Advocate within the governor's Office of Business and Economic Development, to ensure that adequate marketing, education and outreach are undertaken to enable small business customers to fully participate in demand-side energy management programs.

MISO NEWS

MISO Renewable Study Predicts Later Peak, Narrower LOLE Risk

By Amanda Durish Cook



Loss-of-load risk with renewable penetration | *MISO*

Increased renewable integration, especially solar generation, will shift MISO's peak load to evening hours, with a spikier but shorter daily loss-of-load risk, according to the initial results of the RTO's new long-term renewable study.

Senior Policy Studies Engineer Jordan Bakke said the study, which has thus far focused only on resource adequacy, found distinct trends as renewable penetration was dialed up by increments of 10% of the resource mix:

- The average daily loss-of-load expectation (LOLE) becomes heightened, though it compresses to a smaller widow later in the day;
- Wind and solar resources are less likely to be able to meet the late-day risk owing to their operational characteristics; but
- Geographically dispersed and diverse technologies like demand response and storage can assist renewables in their ability to meet load.

"We found strong evidence that the sundown part of the day becomes high-risk hours," Bakke told stakeholders at an April 18 Planning Advisory Committee meeting.

MISO's multiyear Renewable Integration Impact Assessment, announced last year, seeks to identify "inflection points" where the growth of renewables and the retirement of baseload units will require changes in the structure or operation of the system.

The study aims to predict how and when reliability will be impacted under heavy renewable output; if there are limits to the amount of wind and solar generation MISO can support; how long before energy storage becomes a requirement; what parts of the grid will be stressed first; and how much renewable energy can be deployed before significant system changes are needed. (See *MISO to Conduct Long-Term Renewable Integration Study*.)

MISO studied an ever-increasing renewable penetration in the footprint, topping off at 100% using a mix of 75% wind, 17.5% utility-scale solar and 7.5% distributed solar.

Bakke said even with a small solar penetration increase, net peak load will shift from 3 p.m. to 6 p.m. MISO currently has 270 MW of installed solar.

"We're seeing some dramatic shifts with relatively low levels of penetration," Bakke explained. "What we're seeing here is even when solar is at 5% penetration, this time shift already occurs … as solar drops off early in the evening."

Bakke also said while MISO's average year-round risk of losing load peaks from "noon to late in the day," the risk period narrows to 5 to about 8 p.m. as more renewables are employed.

Some stakeholders set into an M.C. Escher-esque discussion on the change in loss-of-load risk, saying that while rising solar generation could cause a shift in the traditional peak load pattern, the traditional 3 to 6 p.m. peak demand hours do still exist — albeit muted by increasing solar supply. Some pointed out that a late-day loss-of-load risk falls to hours that historically have had less electricity demand and could be manageable.

Wind on the Wires' Natalie McIntire asked if MISO's study included a scenario in which increasing use of energy storage offsets the sharper loss-of-load risk.

Although MISO's study indicates that storage can help offset the risk, Bakke said MISO used existing levels of non-renewable resources for the study and did not run scenarios with escalating use of energy storage. Customized Energy Solutions' David Sapper said storage scenarios would have been "fundamental" to the early stage of the study.

MISO's early results also show that a 100% renewables scenario can force negative loads during the day, meaning some generation must be curtailed or exported, Bakke said.

But some stakeholders said the need to plan for daytime negative loads is decades away, if it ever happens.

"We have a long way to go to get to 100% renewables, if we ever do. We need to focus on 10, 20, 30 years out," McIntire said.

Bakke agreed, but said, "It's important to look at these things early and often" because just a small increase in solar shows

Continued on page 17

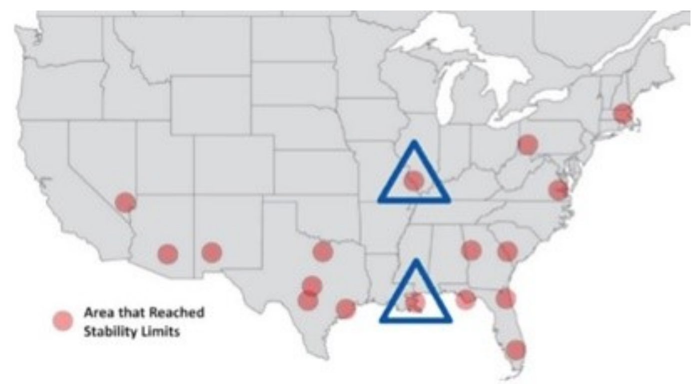
MISO NEWS

MISO Rebuts NERC Findings on Gas Risks

By Amanda Durish Cook

MISO on Wednesday challenged a 2017 NERC assessment that found two areas in the RTO would "experience transmission challenges during an extreme event" involving a disruption of natural gas delivery.

Late last year, NERC released the results of an assessment that studied 24 "geographic clusters" that contain more than 2,000 MW of gas-fired generation and said 18 of them "demonstrated the need for additional follow-up and analysis, based on power flow and stability issues" of the "extreme cases" it ran. (See NERC: Natural Gas Dependence Alters Reliability Planning.)



NERC-identified power flow issues (those in MISO in triangles) | *NERC*

"Most of the risks were on the East Coast or in the Southwest, but there were two in MISO," Senior Policy Studies Engineer Jordan Bakke said, referring to an area on the Missouri-Illinois border and the Amite South load pocket in southeast Louisiana.

MISO told the April 18 Planning Advisory Committee meeting that those two areas have access to alternative fuel sources and are not at risk of N-1 contingencies.

"We think the method employed in this study was not the most optimal. … These risks that were found are not necessarily reasonable in MISO," Bakke said. "MISO has assessed the two regions and found that they were not single-source … issues, and do not account for a generator's ability to procure fuel from an alternate pipeline connection."

Bakke said MISO, which has discussed the study results with NERC, will proceed with its own usual natural gas analyses, though it plans to add a feature to verify that dual-fuel units can access their second source of fuel. By November, MISO also plans to release results of an in-progress study on the impact that large gas pipeline contingencies may have on its system. (See "Sign-of-the-Times Studies," MISO in 2018: Storage, Software, Settlements and Studies.)

MISO said it has been studying natural gas disruptions as part of its reliability planning since 2015 and currently uses 31 gas contingencies to evaluate "transmission needs and system risk." MISO has repeatedly reported that only one planning scenario — the long-term loss of the largest natural gas pipeline for the entire summer peak season — would "slightly" elevate a regional loss-of-load risk.

Minnesota Public Utilities Commissioner Matt Schuerger asked if NERC's assessment or MISO analyses had any merit when considering the natural gas generation outages during the extreme cold that hit the RTO in January. MISO staff said virtually all the gas generation outages involved generators with interruptible transportation, and little of the generation experiencing outages had back-up fuel plans.

MISO Renewable Study Predicts Later Peak, Narrower LOLE Risk

Continued from page 16

MISO may have to reallocate generation and load.

MISO found that wind and solar combinations do work symbiotically over an average day, especially in summer, with mid-day solar able to offset small dips in mid-day wind generation.

"They are not the perfect complement to each other, but they do complement one another," Bakke said.

MISO plans to continue the renewable study on an open-ended basis; the RTO said it will continue to study resource adequacy under increasing renewables through the end of the year.

MTEP Resource Siting

In a related matter, Bakke said MISO's 2019 Transmission Expansion Plan resource siting forecasts have been retooled this year to account for renewable adoption. Resource siting will rely on predictions of future energy storage sited at MISO's busiest load buses; MISO predictions on electric vehicle adoption; National Renewable Energy Laboratory predictions on distributed resources; and the usual study from Vibrant Clean Energy that identifies areas ripe for utility-scale wind and solar development. MISO will reveal a first draft of MTEP 19 resource siting in September. (See Renewables, Storage Get More Play in MISO 2019 Planning.)

Meanwhile, the Planning Advisory Committee in June will begin to flesh out how to analyze and recommend energy storage as baseline reliability solutions in the MTEP process, a responsibility passed to it by the Energy Storage Task Force last month. PAC Chair Jeff Webb said MISO may have to submit Tariff changes with FERC to allow storage projects to be considered for reliability purposes.

Webb said staff and stakeholders have until Sept. 15 to propose reliability projects for MTEP 19. Some stakeholders have requested MISO allow storage projects to be submitted as baseline reliability projects in MTEP 19.

MISO NEWS

Stakeholders Concerned over Tx Conflicts in MISO Retirement Plan

By Amanda Durish Cook

MISO stakeholders are concerned about the RTO's unit retirement proposal, saying it could result in conflicts over interconnection service rights between suspended units and those in the queue.

"Folks were not comfortable with granting … conflicting interconnection rights," MISO engineer Patrick Jehring said during an April 17 Planning Subcommittee meeting.

MISO is proposing to model suspended units as offline during the three years of their suspension, then considering them available to participate in local balancing authority dispatch in planning scenarios thereafter. Units that retire during the three-year process by waiving their interconnection rights with MISO will be modeled offline indefinitely in planning models.

Jehring said the modeling plan is like the three-year offline modeling used today but aligns with MISO's new proposal to have generation owners considering a shutdown enter a catch-all suspension period for three planning years.

Owners would no longer have to decide between a permanent retirement and a temporary shutdown, which requires an estimated return-to-service date. Instead, they would have three full planning years to prepare a return to service or decide on retirement. Suspended generators would lose interconnection service after three planning years if they don't resume operations. (See *MISO Readies Retirement Change*.)

Pat Hayes, LS Power transmission policy manager, asked what happens when the owner of a suspended unit returns after the three-year rescission period to find that new generation is poised to assume its interconnection service.

"It's never happened before," Jehring said. In such a case, he said, the projects' local transmission pricing zone would bear the cost risks of the network upgrades necessary to accommodate both the new and existing unit.

"Basically, the stars need to align for this situation to occur. … The likelihood of this occurring is low based on what we've seen in the past and what we expect in the future," Jehring stressed.

Some stakeholders said MISO's modeling still leaves open the risk that local transmission pricing zones will bear the cost of interconnecting two conflicting units.

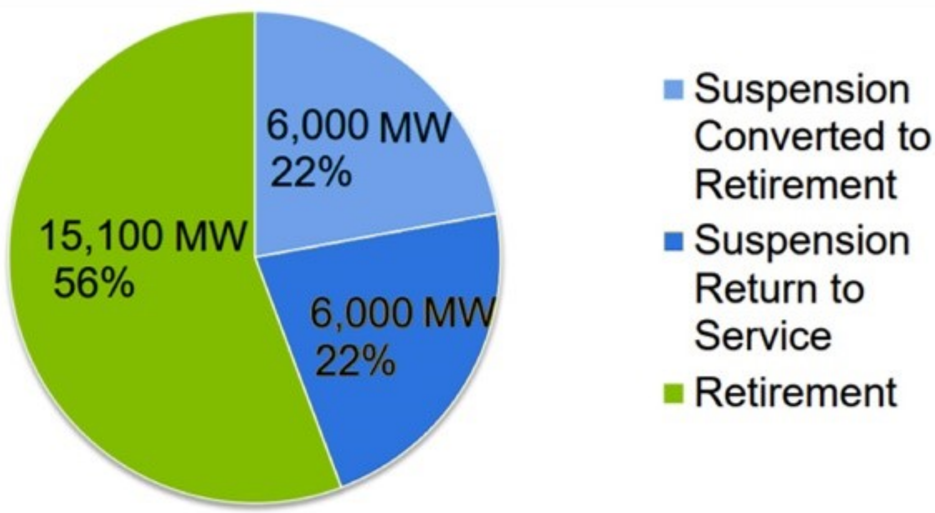
"I guess what I would say to that is the possibility for this rift already occurs today. It's an if-upon-if-upon-if situation to get to that situation," Jehring said.

Of the approximate 27 GW of Attachment Y suspension/retirement notices that MISO has received, Jehring said only 6 GW has returned to service. MISO unit owners typically submit Attachment Y when catastrophic equipment failure occurs or the units become uneconomic to operate. "When we think about the magnitude of it, we're only talking 6,000 MW."

Jehring said including suspended units in the dispatch in modeling after their three-year suspension period doesn't mean the units would ever be dispatched again. The decision to dispatch is based on the "most economic firm resources being utilized to meet a local balancing area's firm load and interchange obligations," according to MISO.

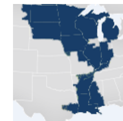
"If a unit goes on suspension for economic reasons, it is unlikely it would be dispatched in the planning models anyway," Jehring said. "The only real reason that a unit will stay on suspension is they're on the economic bubble … and they're truly seeing if they'll become economic again."

MISO will accept written stakeholder comments on the modeling proposal through May 4.



Historical trend of Attachment Y notices | *MISO*

MISO NEWS



FERC OKs MISO TMEP Cost Recovery Schedule

By Amanda Durish Cook

FERC last week approved MISO's proposed cost recovery schedules for its new category of smaller interregional transmission projects with PJM. The commission did not order any changes (ER18-867).

The commission said the tariff schedules for MISO and its transmission owners for recovery of costs on targeted market efficiency projects (TMEPs) was effective April 18.

FERC said the schedules "help to ensure that the transmission owners that construct TMEPs, whether located in MISO or PJM, will have the opportunity to recover the costs of doing so."

The approved schedules assign MISO's share of the project costs to all transmission pricing zones that receive a congestion contribution benefit from the project of at least $5,000 or 1% of the total share per zone. Any zones that don't meet the $5,000/1% threshold would have their costs reallocated to the remaining zones that do. FERC approved MISO's TMEP cost allocation methodology in October.

TMEPs are small interregional transmission projects meant to address historical congestion along MISO and PJM's seams.

The RTOs' boards approved the first TMEP portfolio last year, consisting of five congestion-relieving upgrades in Illinois, Indiana, Michigan and Ohio. The projects, which have individual $20 million cost caps, will coincidentally cost $20 million combined. On average, the projects' costs will be allocated 69% to PJM and 31% to MISO based on projected benefits, which are expected to reach $100 million.

Regulators from MISO South challenged the recovery schedules, as they similarly challenged MISO's regional cost allocation plan. The Arkansas, Louisiana, Mississippi and Texas public service commissions, and the New Orleans City Council, asked FERC to require MISO clarify that the TMEP schedules do not apply to South. They also wanted a commitment that MISO will create a new TMEP cost allocation methodology before the December expiration of the five-year transition period that limits cost-sharing in South.

FERC said the regulators' requests were beyond the scope of the proceeding. The commission said last month in a separate docket that MISO has already committed to filing a new regional cost-sharing method for its share of TMEP costs after the transition period. (See *Rehearing Denied on MISO South Cost Allocation*.)

The Mississippi PSC had also argued for a four-year limit on TMEP cost recovery; FERC declined to order such a provision.

New TMEPs in 2019?

At an April 18 MISO Planning Advisory Committee meeting, Eric Thoms, manager of interregional planning and coordination, said MISO and PJM are evaluating the need for a new TMEP study this year.

Thoms said that MISO is leaning in favor of a study, as the RTOs have experienced about $500 million in congestion payments on more than 200 market-to-market flowgates from 2016 to 2017.

"All indications are at this point that it would be prudent to proceed with a TMEP study this year," Thoms said.

By May, the RTOs will also make an announcement on whether they will begin a traditional two-year coordinated system plan study to identify more expensive seams projects. The RTOs have yet to approve a major seams transmission project under their interregional market efficiency project category.

NYISO NEWS

NYPSC OKs Con Ed EV Charging Program, REV Initiatives

By Michael Kuser

The New York Public Service Commission on Thursday approved a seven-year tariff for Consolidated Edison's electric vehicle quick-charging station program (17-E-0814).

Under the tariff, the utility will expand the scope of its economic development Business Incentive Rate (BIR) to be available to owners of EV quick-charging stations with a minimum aggregate charging capacity of 100 kW and a maximum aggregate demand of 2,000 kW in New York City and Westchester County. The program could support more than 85,000 EVs by the end of the seven-year program, the company said.


Mary Ann Sorrentino

"The city already indicated the program will complement its efforts in increasing access to quick-charging infrastructure," said Department of Public Service staffer Mary Ann Sorrentino.

The New York State Energy Research and Development Authority indicated that Con Ed's program, coupled with NYSERDA's incentives, will likely achieve the near-term economics necessary for greater uptake and installation of quick-charging stations, she said.

The New York City area was one of 17 metro areas selected for the first cycle of $250 million in spending on zero-emission vehicle infrastructure under the $2 billion Volkswagen settlement for violating the Clean Air Act.

The state expects to receive $127.7 million for air pollution mitigation projects, according to a Department of Environmental Conservation report.

Delaying implementation of the Con Ed EV program would result in decreased uptake and a missed opportunity to leverage the BIR to maximize new investment in the utility's territory, Sorrentino said.

PSC Commissioner Diane Burman voted against the tariff filing, without prejudice.

"I think we're oversimplifying the issues here," Burman said. "I don't understand how this is not in conflict with moving forward at this time. Are we saying that failure to act now is going to cause us to not be able to get the VW settlement monies in the New York City area? Because there's nothing in the record to say that we need this for the VW settlement monies."

Warren Myers, DPS director of regulatory economics, said, "This is a very specific program that, to me, is very consistent with all of our economic development flex-rate programs that have been around for years and years. This is a way, as Commissioner [Gregg] Sayre said, to try to attract load that otherwise would not come to the electric utility."

The PSC on April 19 also instituted a proceeding (18-E-0138) to encourage greater penetration of EVs and related supply equipment, possibly through the solicitation of scalable pilot programs.

The new proceeding supports other state initiatives such as ChargeNY — Gov. Andrew Cuomo's goal of installing 10,000 EV charging stations by 2021, up from 2,000 today.

As in the Con Ed charging station program, utilities will help design rates to incentivize off-peak charging and invest in EV infrastructure and related supply equipment. The commission will soon announce the stakeholder feedback schedule for the new initiative.

John B. Rhodes

"This proceeding is important because we need a framework that will get this right in respect [to] the costs, the benefits and the issues for the distribution grid that arise out of the penetration of electric vehicles," said PSC Chair John B. Rhodes.

More REV

The PSC also acted on other initiatives under the Reforming the Energy Vision strategy to lead on climate change: expanding the integration of energy storage systems onto the grid; approving an upstate community smart energy project; creating an online platform for data sharing among energy companies; and streamlining permitting for farmers using anaerobic digesters to produce electricity.

In the matter of the Value of Distributed Energy Resources initiative (15-E-0751), the commission ordered that distributed generation suppliers be allowed to connect energy storage projects up to 5 MW to distribution systems. In addition, the commission issued two orders (18-E-0018; 15-E-0557) to improve the standardized interconnection requirements application and contract process to allow developers to connect projects to the grid without undue delay.

"Our standardized interconnection requirement simply can't stand still," Sayre said. "Some of the changes in this item are necessary because of our orders on the Value of Distributed Energy Resources, some of them come out of the stakeholder process to improve the interconnection process, and still others are necessary to accommodate technological and market changes in areas like energy storage."

The commission approved New York State Electric and Gas' request to implement a pilot program of time-differentiated electric rate options, the Energy Smart Community project, which includes deploying advanced metering infrastructure to approximately 12,000 customers in Ithaca and the surrounding area.

The Utility Energy Registry approved by the PSC will make load data for the major utilities available for local planning, market research and community choice aggregation development, without providing individuals' consumption profiles.

The commission also ordered that community distributed generation (CDG) projects serving only farm customers no longer be required to comply with several CDG program requirements, including the 10-member minimum.

Rhodes closed the session by reading a resolution of appreciation for DPS Chief of Electric Rates and Tariffs Michael Twergo, who is retiring after 32 years of service.

NYISO News

NY Task Force Briefed on Carbon Charge Mechanics

By Michael Kuser

NYISO last week presented two options for pricing carbon emissions in the ISO's wholesale market, saying the approach the ISO favors would not require changes to its commitment/dispatch software or the frequency of settlements.

"The cost of carbon will be known ahead of time, will be known to market participants," said ISO staffer Nathaniel Gilbraith, who delivered the report to the Integrating Public Policy Task Force (IPPTF), which is jointly run by NYISO and the state's Department of Public Service. The April 16 discussion was part of issue "Track 2" in the group's five-track effort to price carbon emissions.

The ISO's preferred approach would have suppliers embed the carbon charges into their all-in day-ahead and real-time energy offers, as they currently do with emissions costs under the Regional Greenhouse Gas Initiative.

Under the second approach, suppliers would submit emissions information for each segment of energy offers (start-up, no-load and incremental energy in dollars per megawatt-hour) with the ISO incorporating the information to calculate a carbon shadow price. It would require software changes.

Under both options, the ISO would dispatch units as it currently does to minimize production costs subject to system constraints. In either case, carbon charges might also need to be trued up, Gilbraith said.

Day-ahead market zonal LBMP, April 16, 2018 (marginal cost of energy: $42.37) | *NYISO*

The carbon price for generators subject to RGGI would be the social cost of carbon determined by the New York Public Service Commission minus the RGGI price. Generators not subject to RGGI, such as fossil fuel plants of less than 25 MW, would pay the full social cost.

The ISO could estimate emissions for the generators but would prefer to let suppliers self-report, said IPPTF co-chair Nicole Bouchez, NYISO principal economist. "We thought it made sense to have the companies who have the best information about their plants to do all that math instead of the ISO having to do, by necessity, approximations of it," she said.

Another complexity is that emissions vary based on a plant's heat rate, fuel type and where in the output range they are, she said.

"In order to really know the carbon output, you need to know the exact heat rate as well as the fuel that's being used at that

Continued on page 22

NYISO NEWS

NY Task Force Briefed on Carbon Charge Mechanics

Continued from page 21

moment and what the carbon content of the fuel is," Bouchez said. "Then there's the question of start-up and no-load carbon emissions as well."

Bouchez walked stakeholders through the ISO's current bid and settlement process and how it might change under a carbon pricing regime.

Besides the current day-ahead and real-time market settlements, "the carbon charge would introduce an additional generator settlement line item, which is based on the actual emissions that day times the applicable price in dollars per ton," Bouchez said. "[This] gives the dollar carbon charges that would be charged to that generator, and that is based on the actual physical output of the plant."

Loads would continue to pay the applicable locational-based marginal price (LBMP) for energy withdrawals. The process would also create a carbon charge "residual," a dollar amount to be paid to load-serving entities to minimize the increase in retail electricity prices. The allocation of residuals will be discussed at a future task force meeting.

Price Transparency

Couch White attorney Michael Mager, who represents a coalition of large industrial, commercial and institutional energy customers known as "Multiple Intervenors," asked what would be included in the market price. "Would the final market price be the LBMP plus carbon adder, minus the amount that's passed back to load-serving entities? What would be transparent and public for every hour?"

Because many end-use customers have supplier contracts based on the market prices, "I think the customers are going to want to know that any money that's passed back to LSEs at the wholesale level actually gets passed back to the consumers at the retail level, so I think they're going to need transparency in terms of that price as well," Mager said.

"The LBMP is still going to exist as the primary cost of a unit of energy," Gilbraith said. "Similar to today, there are other associated charges, uplift or whatnot, that are allocated to loads. The joint staff team will be working through in June a proposal on how to allocate the carbon residuals back, and that's a great issue to bring up in that venue, what data and what is made public through that process and at what level of granularity."

Real-time Emissions

"These calculations are going to be done separately for day-ahead and real-time, and so all of this charging and reconciliation would be done separately for each market. Is that accurate?" asked Howard Fromer, director of market policy for PSEG Power New York.

"Day-ahead and real-time LMBPs will continue to exist as they do today, and so they will be developed based on day-ahead and real-time offers," Gilbraith responded. "However, energy is only physically produced pursuant to a real-time schedule, so the only way a bill [for the carbon charge] will occur is ... based upon a real-time schedule. ... It's based on actual, physical electricity production and the emissions associated with that production."

The task force met again Monday at NYISO headquarters. Check next week's *RTO Insider* for coverage.

PJM NEWS

Report: Nuke Loss Would Undo Renewable Growth

By Rory D. Sweeney

The closure of four nuclear plants in Pennsylvania and Ohio would result in substantial increases in electricity bills and carbon dioxide emissions, among other air pollutants, while cutting jobs and economic productivity, according to a Brattle Group report released last week.

The report, commissioned by Nuclear Matters, a bipartisan pro-nuclear advocacy group, focuses on the Three Mile Island unit that Exelon said last year it will close and the three plants FirstEnergy Solutions announced on March 28 it was closing: Davis-Besse and Perry in Ohio and Beaver Valley in Pennsylvania. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

The closures would trigger price increases of up to $2.43/MWh for Ohioans and $1.77/MWh for Pennsylvanians and eliminate the environmental benefit of all the zero-emission generation installed in PJM over the past 25 years, according to the report. The four plants' 4,745 MW generat-

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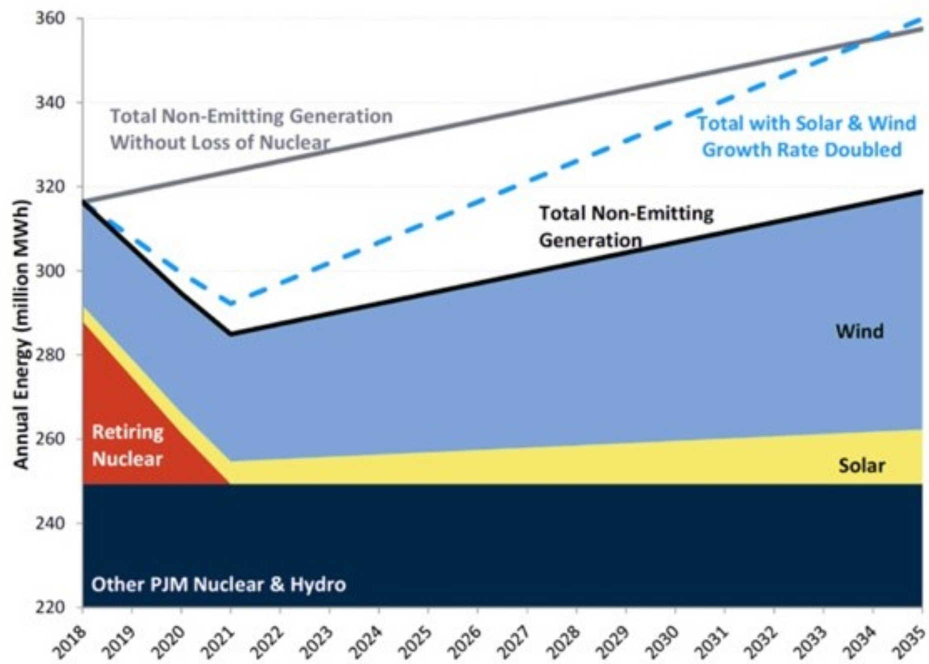


The graph shows that replacing the emissions-free generation of the four nuclear units currently slated for closure in PJM would take 14 years. Matching the emissions-free output expected in PJM at the current trajectory would require doubling the current deployment rate of renewables and another two years. | *The Brattle Group*

PJM: Won't Abandon AI Project on Nuke Closure Threats

By Rory D. Sweeney

The Artificial Island transmission project could change or become unnecessary if the two nuclear plants it's intended to support are shuttered, but retirement threats by plant owners aren't sufficient to revise the project, the PJM Board of Managers said last week.

The board made the acknowledgement in response to concerns highlighted by the Delaware Energy Users Group in a March 12 letter. Michael K. Messer, the group's president, urged the board to re-evaluate and potentially cancel the project following threats by owners of the plants, Exelon and Public Service Enterprise Group, to close them. (See *Del. Group Seeks to Block Artificial Island Project*.)

"I can say with a degree of certainty that the retirement of one or more plants at the Artificial Island site would impact the scope of the transmission project," PJM CEO Andy Ott, a board member, wrote. "However, at this time, absent announced retirements of either Salem or Hope Creek, the project assumptions remain intact."

Exelon and PSEG have announced that they will cancel future capital investments at the two Salem nuclear units they co-own and shut the plants down if New Jersey doesn't provide them financial support. The state legislature has passed a bill that would provide the plants with subsidies costing ratepayers about $300 million per year. (See *NJ Lawmakers Pass Nuke Subsidies, Boosted RPS*.)

The Artificial Island transmission project was developed to address transmission stability problems at Salem and the neighboring Hope Creek unit in southern New Jersey and allow them to operate at full power without a book-size compilation of operating constraints. PJM's first competitive solicitation under Order 1000, the project has been long mired in controversy. In June, the RTO announced several cost allocation alternatives that would shift much of the $280 million price tag from Delaware ratepayers to those in New Jersey and Pennsylvania. (See *PJM: AI Costs Would Shift to NJ, PA Under New Allocations*.)

Ott confirmed Messer's concerns but said any changes to the project would be considered during the system reliability analysis if either plant submits a deactivation notice. "I agree that the analysis proposed by your letter is analysis that PJM should undertake to determine impact to reliability should a plant announce retirement and subsequently impact the Artificial Island project," he wrote.

PJM NEWS

Report: Nuke Loss Would Undo Renewable Growth

Continued from page 23

ed 38.7 MWh of electricity in 2017, surpassing the 35 million MWh generated by wind, solar and hydro resources in PJM, the report concluded. It would take 14 years for zero-emissions generation to recover to its 2017 level, Brattle said.

"This means that the retirement of these four nuclear generators would more than undo the entire emissions benefits of all renewable generation investments made to date throughout the PJM region," the report concluded.

Matching the emissions-free output expected in PJM at the current pace would require another two years and doubling the current growth of generation from renewables to 4.8 million MWh annually. Attempting to replace the environmental benefits of the four nuclear plants with renewables could cost around $2 billion annually, based on the Energy Information Administration's national average renewable cost estimates and would not stop the lost capacity from the nuclear closures being replaced by fossil-fuel generation. "We estimate that about 72% of the replacement would come from gas-fired generation and 28% from coal," the report said.

"Following [nuclear plant] Vermont Yankee's shuttering in New England, we saw devastating effects. The loss of tax revenues forced local officials to make major budget concessions to the detriment of their residents, including cutting their municipal budget by 20%, drastically reducing police services and raising their property taxes by 20%," said Judd Gregg, a Nuclear Matters Advocacy Council member and former Republican senator from New Hampshire. "In the year following the closure, carbon emissions increased by 2.5% due to nuclear energy being replaced by emission-producing sources."

Annual CO_2 emissions would increase by more than 20 million metric tons if the plants closed and could create potential social costs of more than $900 million per year. It also would increase annual emissions of air pollutants such as sulfur dioxide, nitrous oxide and criteria particulate pollutants by tens of thousands of tons, with potential social costs of $170 million per year.

Electricity bills would increase by $400 million for Ohio residents, $285 million for Pennsylvanians and $1.5 billion across PJM annually, according to the report, because of increased clearing prices in the capacity and energy markets. At least 3,000 jobs would be "at risk" without including indirect jobs at the plants, and the closures would eliminate tens of millions of dollars in local tax revenues.

David Lochbaum, a nuclear safety engineer with the Union of Concerned Scientists, questioned the study's economic conclusions, telling the *Cleveland Plain Dealer* that other plant closures have not led to economic disasters. "The unemployment in the other states is not rampant, despite the permanently shut down reactors. The price of electricity in the other states is not exorbitant, despite the permanently shut down reactors," he said.

"So, why does Nuclear Matters believe the folks in Ohio and Pennsylvania cannot figure out what folks in other states have figured out?" Lochbaum asked.

Settlement on Abandoned East Coast Tx Line Wins FERC OK

By Amanda Durish Cook

FERC has approved a settlement between PJM, Exelon and the Illinois Commerce Commission over abandonment costs for the canceled Mid-Atlantic Power Pathway (MAPP) transmission project.

Under the uncontested settlement accepted by FERC on Thursday, Exelon subsidiary Baltimore Gas and Electric's pricing zone will bear more costs of the project while the Commonwealth Edison zone's responsibility will not exceed $75,000 — less than half of the costs it was originally assigned. FERC said PJM must disburse refunds if the ComEd zone has already paid more than $75,000 (ER17-1016-001).

Proposed more than a decade ago, the $1.05 billion, 500-kV MAPP project would have extended about 230 miles from northeastern Virginia through southern Maryland and Delaware, crossing beneath the Chesapeake Bay and Choptank River to southwestern New Jersey.

In 2009, PJM assigned BGE two baseline upgrades for the project, but the RTO's Board of Managers canceled the project in 2012, saying it was no longer needed to maintain reliability. The line was originally included in PJM's 2007 Regional Transmission Expansion Plan.

Early last year, PJM submitted Tariff revisions on BGE's behalf so the utility could recover about $1.2 million in abandoned plant costs.

The ICC protested, arguing that ComEd should not have to bear the costs of a canceled line that never stood to benefit its Midwestern territory. ComEd's zone stood to incur 13.43% of the cost of BGE's upgrades under PJM's postage stamp cost allocation methodology.

"Given that MAPP is a canceled project, the ComEd zone does not derive any benefits from the MAPP project. … The load in the ComEd zone did not contribute to the reliability factors that caused PJM to add the MAPP project to the RTEP in the first place. The beneficiaries and cost causers of the MAPP project are located on the East Coast and that is where the commission should allocate the costs," the ICC wrote.

The ICC also pointed to rulings by the 7th U.S. Circuit Court of Appeals, which twice remanded FERC's approval of PJM's regionwide postage stamp cost allocation for new 500-kV+ transmission projects (See *Despite Lengthy Negotiations, PJM Cost Allocation Settlement Still Finds Detractors*.) The 7th Circuit said that PJM's high-voltage lines are "all located in PJM's eastern region, primarily benefit that region and should not be allowed to shift a grossly disproportionate share of their costs to western utilities on which the eastern projects will confer only future, speculative and limited benefits."

PJM NEWS

MRC Briefs

Balancing Ratio Study Changed

WILMINGTON, Del. — Has the door for revising Capacity Performance calculations been opened too far? Some stakeholders fear so after members at last week's Markets and Reliability Committee meeting endorsed revisions to an issue charge for an initiative examining the calculation of the balancing ratio used in setting capacity offer caps.

Originally, the market seller offer cap (MSOC) equation was out of scope in the inquiry being conducted by the Market Implementation Committee and members were only focused on how to determine the balancing ratio.

The balancing ratio needs to be addressed because it is currently based on the number of performance assessment intervals PJM experienced in the past three years, and it can't be determined if there are no such events. That became a reality this year, requiring PJM to reuse last year's as a stopgap until a new calculation is developed. (See "Stopgap Balancing Ratio OK'd Despite Questions," *PJM MRC/MC Briefs 10-26-17*.)

Beyond the balancing ratio, the issue charge also allows for evaluating how many assessment intervals are assumed in calculating the nonperformance charge rate. The current assumption is 30 intervals per year, which some stakeholders have argued is too high.

Exelon's Jason Barker points to a FERC order that he argued shows the commission's intent to maintain the equation for an offer cap as the net cost of new entry for a unit's technology class multiplied by the balancing ratio. | © *RTO Insider*

But Joe Bowring, PJM's Independent Market Monitor, pointed out that changes to the nonperformance charge can affect the MSOC, so the MIC needs the latitude to consider changes to it as well. It's important to maintain the consistent relationship between the nonperformance charge rate and the MSOC, said PJM's Pat Bruno, who was presenting the proposal.

"We can't keep the equation 'net [cost of new entry] times B' as the default offer cap out of scope with this issue charge because any changes we make with the nonperformance charge rate may impact that default offer cap equation," he said.

Exelon's Jason Barker questioned that position, arguing that FERC approved the specific MSOC equation — the net CONE for a unit's technology class multiplied by the balancing ratio. He said all the necessary assessment-interval changes can be made while keeping "the FERC-approved tether to net CONE" by ensuring the interval calculation remains consistent throughout the formulas, a point on which Bruno agreed.

Barker said that — and not a potential wholesale re-evaluation of the MSOC — is what he believed stakeholders were agreeing to when they approved the issue charge. Other stakeholders agreed.

"I don't think there's anything in the issue charge as it stands now that would prevent us from completely changing the nonperformance charge rate," Bruno acknowledged.

But Bowring argued there's nothing "magical" about the current MSOC and that FERC approved the logic through which the equation was developed.

"You have to address this additional question if all of these issues are at play, which they are at the moment," he said.

Barker said he couldn't endorse the widened scope and encouraged others to vote against it as well.

Other stakeholders voiced concerns about the potential effect on other market mechanics, but Barker's lobbying fell short. The proposal was endorsed with five objections and one abstention.

Offer Cap Walk Back Stalled

PJM's hope to return to previous language over energy market offer caps was dashed after stakeholders agreed with Bowring that the previous rules also weren't correct.

Members approved the current Manual 11 language at the October 2017 MRC to comply with FERC Order 831. PJM staff subsequently discovered the revisions restrict market-based offers to $1,000/MWh, contradicting language in the Operating Agreement. The proposal would have reverted to previous rules that market-based incremental energy offers may not exceed $1,000/MWh unless the cost-based incremental energy offer is greater than that amount. In that case, the market-based incremental energy offer is capped at the lesser of the cost-based incremental energy offer or $2,000/MWh.

The current proposal was pushed through PJM's stakeholder process unusually quickly, with a first reading at the Members Committee webinar just three days before the MRC meeting. PJM's Rami Dirani said the quick turnaround was necessary to maintain consistency because the order became effective on April 12. He described the return to the prior language as "very straightforward," but Bowring disagreed.

"It doesn't strike me as being so straightforward," he said, noting that the previous rules didn't address PJM's obligation to verify cost-based offers *ex ante* — based on forecasts — and ensure that price-based offers not exceed cost-based offers of more than $1,000.

Carl Johnson, representing the PJM Public Power Coalition, noted that many Manual 11 changes were being discussed in October, "so maybe it just slipped our focus. But I thought we knew what we were doing then, and it's clear from reading the manual language that we didn't."

The changes were originally made to reduce complexity, Dirani said.

"The inclination would be to spend a little more time on this rather than move another … rule that is not right," Johnson said.

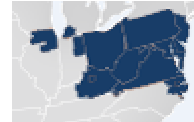
Other stakeholders agreed.

Calpine's David "Scarp" Scarpignato asked that PJM return with some comparison of potential rule changes.

"I need to know more than just the mechanics," he said.

Continued on page 26

PJM NEWS



FERC OKs PJM Plan for State Carveouts on EE Resources

Reiterates 'Exclusive' FERC Authority

By Rory D. Sweeney

FERC last week approved PJM's proposed rules for implementing restrictions imposed on energy efficiency resources (EERs) by state or local regulators that are authorized by the commission to restrict their sale in the RTO's markets (ER18-870).

The commission simultaneously denied rehearing of a related order it issued in December that asserted the commission had "exclusive authority" over the participation of energy efficiency in wholesale markets while preserving a carveout it approved earlier for Kentucky utilities (EL17-75-001).

The order was prompted by a June 2017 petition by Advanced Energy Economy for a declaratory order that FERC — and not state or local regulators — has authority over how EERs participate in wholesale markets. FERC sided with AEE in the December order. (See *FERC Claims Jurisdiction on EE, OKs Ky. Opt-Out*.)

PJM Plan

PJM's plan creates a verification process to ensure that all EERs offered and cleared in the RTO's capacity market comply with any restrictions that may be imposed by a relevant electric retail regulatory authority (RERRA). It also helps sellers of EERs that cleared in a prior PJM capacity market auction but are subsequently restricted from participation in the market by a RERRA.

The RTO will post a FERC-authorized notice of a RERRA's restrictions. Sellers in the capacity market will be required to itemize EERs located within a RERRA's boundaries and submit the list to PJM, which will distribute lists of EERs to relevant electric distribution companies. The EDCs will be required to proactively affirm compliance with PJM before the EERs can participate.

EERs are different from demand response resources, PJM explained, because they are eligible to participate unless a RERRA restricts them. In contrast, DR is ineligible to participate unless a RERRA affirmatively permits them.

EERs that are made ineligible by RERRA regulations after they've cleared an auction may obtain replacement capacity or elect to be relieved of the capacity commitments.

"Such a rule protects sellers of EERs from being assessed deficiency charges or Capacity Performance nonperformance charges," the commission explained.

Rehearing Denial

Several parties — including FirstEnergy, several public power groups and several Midwestern transmission and distribution utilities — requested rehearing or clarification of the commission's December ruling on exclusive authority. They alleged that FERC overreached in pre-empting state authority to oversee EERs.

"We find that the commission's authority to determine which resources are eligible to participate in the wholesale markets is a fundamental component of the regulation of the wholesale markets," the commission responded, drawing a distinction between state authority to procure renewable energy and FERC's authority over EERs.

"Our determinations here do not prevent states from regulating retail sales of electricity, even when such regulation incidentally affects areas within the commission's domain," the commission said.

However, the commission said it also disagreed with American Municipal Power, the American Public Power Association, National Rural Electric Cooperative Association and Public Power Association of New Jersey "that state and local restrictions on EER participation in wholesale markets is a valid exercise of state and local authority over retail electric service. A provision directly restricting retail customers' participation in organized wholesale electricity markets, even if contained in the terms of retail service, nonetheless intrudes on the commission's jurisdiction over the wholesale markets."

FERC specifically declined to address whether its conclusion is based on the "field pre-emption" or "conflict pre-emption" under the Supremacy Clause of the Constitution.

"Because we conclude that the question of which resources may participate in wholesale markets is fundamental to the regulation thereof, we need not specifically address whether Congress 'occupied' the relevant field or whether a state law arrogating that authority to the state merely 'stands as an obstacle' to the commission's responsibilities under the [Federal Power Act]," FERC explained.

MRC Briefs

Continued from page 25

"I'm sure it seems simple; you're going back to previous language. So I'm sure it felt simple, but it has obviously led to further questions," said Adrien Ford with Old Dominion Electric Cooperative.

Staff agreed to send the issue back to the MIC for discussion but said they aimed to get feedback in time to have a proposal prepared for a vote at next month's MRC.

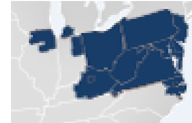
Price Formation Reshuffle

PJM's Adam Keech outlined staff's plan to address energy market price formation changes in accordance with the Board of Managers' request that stakeholders break the issue into pieces so that less controversial changes can be implemented sooner. The board made its request in a letter April 11. (See *PJM Board Seeks Reserve Pricing Changes for Winter*.)

The plan breaks potential changes into short-, mid- and long-term goals that correspond with the board's request that some reserve market changes be ready for implementation by next winter and that other energy market changes be prepared for next spring.

Continued on page 27

PJM News



MRC Briefs

Continued from page 26

In the short term, PJM plans to focus on the synchronized reserve market, dynamic reserve zone modeling, simplifying the operating reserve demand curve (ORDC) and fast-start pricing if FERC approves the proposal PJM has already filed.

The mid-term topics for the first quarter of 2019 would include developing a 30-minute reserve product, along with additional revisions to the ORDC and fast-start pricing.

The long-term plan would extend the implementation of integer relaxation and look to add shortage pricing to the day-ahead market.

"My interpretation of the discussions [at the most recent meeting of the Energy Price Formation Senior Task Force] was there were no objections to moving forward with that," Keech said.

Greg Poulos, the executive director of the Consumer Advocates of the PJM States, said his members don't necessarily see the need to make these changes, "but we are aligned with the goals" of analyzing the situation to see if any changes are warranted.

The consumer advocates are particularly interested in cost-impact analyses, he said.

Stakeholders OK Manual, Operating Agreement Changes

Members approved changes to Manual 12: Balancing Operations to incorporate rules approved by FERC in November regarding reviews required for approval of pseudo-tied generators. The changes were endorsed with two objections and three abstentions. (See "External Capacity," *PJM PC/TEAC Briefs: March 8, 2018*.)

Stakeholders also endorsed unanimously several manual revisions and other operational changes:

- Manual 14A: New Services Request Process. The revisions clarify language to match existing procedures and add language to describe in detail system impact study (SIS) and interconnection feasibility study analyses. In January, a FERC administrative law judge issued an initial decision finding that PJM's process is unjust and unreasonable because of a lack of transparency (EL15-79). On Feb. 20, PJM filed a brief on exceptions challenging the ruling. (See *FERC Judge Faults PJM, TOs on Transmission Upgrade Process*.)
- Manual 14B: Regional Transmission Planning Process. The revisions are the result of a periodic review that identified several administrative changes, including a revision to the generator deliverability procedure and adding the Ohio Valley Electric Corp. to the western region study area definition. (See "Transformer Consideration Changed for Gen Deliverability," *PJM PC/TEAC Briefs: March 8, 2018*.)
- Manual 28: Operating Agreement Accounting. The revisions address changes to comply with FERC Order 825 implementing five-minute settlements. Also makes a technical correction for the revenue data used to calculate settlements for generation resources. (See "Order 825 Implementation Moves Forward," *PJM Market Implementation Committee Briefs*.)
- Revisions to the Operating Committee charter to replace the term "spinning reserve" with "synchronized reserves" to match the language in PJM manuals.

— Rory D. Sweeney

| © RTO Insider

SPP News

FERC Rejects Rehearing on SPP Cost Allocation Reviews

By Tom Kleckner

FERC on Thursday denied a challenge by Sunflower Electric Power and Mid-Kansas Electric to the commission's 2017 order allowing SPP to change its regional cost allocation review (RCAR) analysis from at least once every three years to once every six years (ER17-2229).

The commission said Sunflower and Mid-Kansas reiterated arguments they made in protesting the original order, when they said problems with the RCAR's study assumptions, analysis and results made it unreasonable to decrease its frequency. The commission ruled their concerns as being out of scope. (See *FERC Approves 6-Year Cycle for SPP RCAR Review*.)

In rejecting the request, FERC said SPP's decision to lengthen the review cycle "is further supported by SPP's desire to avoid the expense of the RCAR analysis and by the fact that a vast majority of SPP zones have been at or above a 1-to-1 benefit-to-cost ratio."

The commission said the companies failed to back up their claim that SPP's Regional State Committee would be unresponsive to members facing an imbalance in cost allocation, or that they would need to conduct a study to request relief through the revised Tariff. "Parties could use existing data and studies to support a request," FERC said.

"Further … SPP has in the past taken action to address stakeholder concerns related to cost allocation, and we expect it will respond in a like manner if presented with evidence the allocation has become inequitable," the commission said. It noted the RTO had said "no individual transmission owners would be required to conduct a study prior to requesting that SPP perform an RCAR analysis."

FERC also found no merit to Sunflower and Mid-Kansas' argument that $7.8 billion in current base plan projects and expected increases in transmission investment suggests that the frequency of the RCAR analysis should remain at three years. The commission said that SPP was able to show that, compared to prior periods, "the overall pace of increase of transmission costs within the SPP footprint has slowed."

Stakeholders approved a task force's proposal to institute a six-year planning cycle in April 2017. The task force said the change would save SPP manpower and consulting costs. (See "RSC Approves Six-Year Cost Allocation Review," *SPP Regional State Committee Briefs*.)

SPP's cost allocation methodology, the "Highway/Byway" method, assigns 100% of all 300-kV+ transmission upgrades to zones on a regional basis.

The most recent regional cost review (RCAR II), released in July 2016, showed an overall 2.46:1 benefit-cost ratio for projects approved since June 2010 under the Highway/Byway methodology — a big increase from RCAR I, which showed a 1.39:1 ratio. Only one transmission zone was below the 0.80 threshold established by the Regional Allocation Review Task Force.

SPP said it took about 2,100 employee hours and more than $417,000 in payments to consultants to complete that review. The two RCARs have cost more than $1.5 million in consulting fees, and each study has taken at least six months to complete, according to the RTO.

SPP NEWS

Xcel Pulls out of Mountain West, Endangering SPP Integration

Continued from page 1

Top SPP RSC Concerns.)

The decision left several of Mountain West's entities pondering their next steps. With 1.4 million customers, Xcel's Public Service Company of Colorado subsidiary represents about 40% of Mountain West's base.

Lee Boughey, senior manager of communications and public affairs for Tri-State Generation and Transmission Association, said the cooperative would "take time to review its options and determine the best approach to move forward."

"Ultimately, any decision to participate in a regional transmission organization will be dependent on whether it benefits our members," Boughey said.

Tri-State is a member of both Mountain West and SPP, having joined the RTO as part of the Integrated System's membership in 2015.

Theresa Donnelly, senior communications manager for Black Hills Corp., said her company is also "evaluating the impact" of Xcel's departure from the SPP integration effort.

"We will continue our discussions in the coming days and weeks," Donnelly said. "We respect Xcel Energy's decision to end their participation in Mountain West, as the benefits and costs of RTO membership differ for each company based on their unique business situation and interests."

Mountain West, which primarily services Colorado, Wyoming and Nebraska, began discussing RTO membership in 2013. It announced in January 2017 that it was pursuing membership in SPP, and in March, the RTO's Board of Directors approved a set of policy recommendations intended to govern the terms of Mountain West's membership. (See *SPP Begins Work of Integrating Mountain West*.)

Xcel said "a variety of interrelated items" drove the company to its decision:

- The limited overall benefits to Xcel's customers, "given the relatively small size of the MWTG footprint."

Colorado wind farm | *Xcel Energy*

- The few opportunities for westward expansion of the RTO, "which might have added to the value proposition."
- A recent increase in the costs of forming an RTO, with "less certain" benefits that are "highly dependent on both the footprint, generation flexibility and composition of" Mountain West.
- Recent developments with RTOs have "introduced an increased risk of more significant changes to state-regulated retail electric service than Xcel Energy had anticipated."

"Xcel Energy will continue to focus on initiatives that will benefit our customers, keep bills low and facilitate the addition of renewable resources on our system," Eves said. "Our customers and the state of Colorado benefit when states control their own energy policy."

Colorado's Public Utilities Commission, which has jurisdictional authority over Xcel and Black Hills, was thought to be the primary stumbling block to completing the Mountain West's integration. The PUC declined to comment Saturday.

Denver-based attorney Abby Briggerman, who represents consumer groups before FERC, said in a statement: "We appreciate Xcel's efforts to ensure meaningful savings for ratepayers and hope that whatever the alternatives considered, there will be a transparent stakeholder process to allow for comprehensive consideration of the best course forward."

The Western Area Power Administration issued a statement saying it "appreciates the strong collaborative partnerships" within Mountain West and "is assessing [its] next steps" following Xcel's withdrawal.

"WAPA maintains its commitment to working with neighboring entities across its 15-state footprint to develop strategies to adapt to the evolving electricity industry," said Chief Public Affairs Officer Teresa K. Waugh. "We will continue to evaluate and pursue opportunities to optimize the utilization of generation and transmission resources across multiple utility systems."

In recent weeks, a growing number of SPP stakeholders have pushed back against the Mountain West integration. A group of five members filed a letter April 6 asking the RTO's board to reconsider its decision to move forward with the integration until "there is more consensus within the SPP membership as to how to proceed." (See *SPP Group Balks at Mountain West Concessions*.)

On Wednesday, Lincoln Electric System (LES) issued its own letter, saying it agrees with the April 6 missive that the board should reconsider the approved MWTG policy recommendations.

LES said it is concerned about the recommendation proposing regionwide cost allocation for the Mountain West DC ties. "The expectation that existing SPP members would pay for DC tie legacy facilities is unprecedented and in contravention to the SPP Tariff," wrote LES CEO Kevin Wailes.

LES also said there is no policy justification for the proposed three-year phase-in administrative fee discount for Mountain West members. "If the purported benefits of the [Mountain West] integration have been accurately represented, there should be no need for one subset of SPP transmission owners to subsidize another subset during this period," Wailes said. "Like others, we are in support of efforts to strategically bring in new entities that aren't at the unnecessary expense of SPP's existing members," he added.

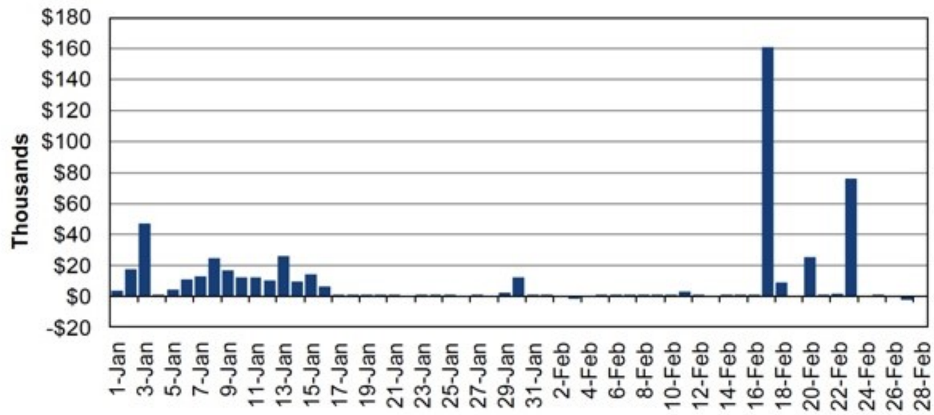
On Friday, the Missouri Joint Municipal Electric Utility Commission and the municipal utilities of Springfield and Independence, Mo., filed a joint letter outlining their concerns in language almost identical to that of LES.

SPP's board and its Members Committee are scheduled to meet today in Kansas City, Mo. The agenda includes a Mountain West update and a president's report, which will likely generate much discussion.

FERC & FEDERAL NEWS

FERC Orders RTOs to Shine Light on Uplift Data

By Michael Brooks



CAISO's exceptional dispatch uplift costs for January and February 2018. The ISO includes these graphs in its monthly Market Performance Reports, but some stakeholders noted that it does not include the underlying data. FERC said this level of transparency was insufficient. | *CAISO*

WASHINGTON — RTOs and ISOs will be required to submit monthly reports detailing their uplift payments and operator-initiated commitments under a rule that FERC said would increase transparency in the wholesale markets (RM17-2).

But the commission's order Thursday withdrew a requirement that grid operators categorize real-time uplift costs based on their causes and allocate them only to market participants "whose transactions are reasonably expected to have caused" the uplift.

FERC made both proposals in a 2017 Notice of Proposed Rulemaking the commission issued in January 2017 as part of a larger price formation initiative it began in 2014. (See *FERC Seeks More Transparency, Cost Causation on Uplift*.) Thursday's order marked the last "generic" action it took as part of that initiative, FERC said.

Under the new rule, RTOs and ISOs will be required to report:

- total uplift payments for each transmission zone, separated by day and uplift category;
- total uplift payments for each resource monthly; and
- megawatts of operator-initiated commitments in or near real time and after the close of the day-ahead market, broken out by transmission zone and the reason for the commitment.

Generators receive uplift payments when their production costs exceed their energy and ancillary services revenues. Operator-initiated commitments refer to when a generator operates at the direction of the grid operator at a loss for reliability reasons.

Penalty Factors

Grid operators will also be required to revise their tariffs to include the transmission constraint penalty factors used in their market software, the circumstances under which those factors can set LMPs and any processes by which they can be changed. Penalty factors are the maximum prices RTOs pay to redispatch resources before allowing power flow to exceed their maximum operating levels.

FERC found that although all RTOs/ISOs report some information about uplift payments and their causes, their disclosures usually lack detail and are inconsistent across markets. No RTO or ISO reports uplift on a resource-specific basis.

"A lack of transparency regarding uplift payments and operator-initiated commitments can mask system conditions, particularly in times of system stress," Adam Cornelius, of FERC's Office of Energy Policy and Innovation, said at Thursday's open meeting. "The result is that market participants may not fully understand the needs of the system or recognize the resource attributes that are required to meet those needs. … Therefore, current reporting practices may not provide sufficient transparency for market participants to plan for and respond to system needs in a cost-effective manner, resulting in rates that are unjust and unreasonable."

The increased transparency will help market participants invest in new infrastructure more efficiently and facilitate more informed stakeholder discussions, he said.

Compliance filings for the rule are due 135 days after its publication in the *Federal Register*, and the grid operators have another 120 days to implement it.

"Uplift isn't the sexiest topic … even compared to FERC topics," Commissioner Cheryl LaFleur joked. "And sometimes it's get a bad name, as if it's a bad thing. But commitment actions that lead to uplift are important" for reliability. The reports will "provide additional information to the marketplace so the marketplace can solve the problems that they reveal," she said.

Commissioner Neil Chatterjee agreed. "It is no secret that transparency in RTO and ISO price formation is not the most riveting subject," he said. "I haven't seen a lot of headlines calling for better reports on uplift, and I wouldn't expect these topics to be trending on Twitter any time soon. …

"But that doesn't mean today's action isn't significant. The final rule is a win for all stakeholders participating in these markets, as they will benefit from the added transparency it will bring to each RTO's commitment, dispatch and settlement processes."

Cost Allocation Proposal Dropped

FERC had proposed that grid operators categorize deviations between the day-ahead and real-time markets, one of the main causes of uplift, as either "helping" (reducing the need for uplift) or "harming" (increasing the need) and that they allocate uplift costs to generators based on the net of their harming deviations.

Continued on page 31

FERC & FEDERAL NEWS

Gas Dominates, Again, in FERC State of the Markets Report

By Michael Brooks

WASHINGTON — By now, it sounds like a broken record.

As they have in the past four years, the trends in natural gas dominated the discussion of FERC's annual State of the Markets report at the commission's open meeting on Thursday.

The report found that average U.S. natural gas spot prices rose 21% in 2017 from 2016, while average day-ahead on-peak LMPs increased 3 to 13% at pricing nodes in RTO/ISO markets.

While the previous two years were marked by cheap prices driven by warm winters, last year saw cold weather at both its beginning and end, with an especially severe cold snap at the end of December and into January 2018 leading to a sharp spike in prices, especially in ISO-NE. (See FERC, RTOs: Grid Performed Better in Jan. Cold Snap vs. 2014.)

| © RTO Insider

Last year also marked the first since 1958 that the U.S. was a net exporter in gas, propelled by increased LNG export capacity. "The largest increase in demand for natural gas came from LNG exports, which

Continued on page 32

FERC Orders RTOs to Shine Light on Uplift Data

Continued from page 30

However, many commenters, while agreeing with the rule's general principle, questioned its feasibility.

Exelon pointed to PJM and the 2014 polar vortex as an example. During the period of extremely cold weather, high natural gas prices led to high energy prices in PJM, and the RTO dispatched high-cost generators to maintain reliability. At the same time, generators in neighboring regions self-scheduled imports into PJM, "chasing" the high prices, which led prices to drop. Thus, the PJM generators' operating costs exceeded their revenues, leading to high uplift payments.

"While the large volume of self-scheduled imports may have 'helped' PJM meet system needs, and would ostensibly qualify as 'helping' deviations as contemplated in the NOPR, these self-scheduled imports nevertheless directly caused the system uplift payments," Exelon said.

"Given the complexity of this issue and the varying practices among RTOs, the NOPR's preliminary finding that *some* existing RTO practices may be unjust and unreasonable does not justify standardizing this aspect of the various RTOs' market design," the Transmission Access Policy Study Group (TAPS) said in its comments.

"If the commission proceeds to a final rule, TAPS generally supports netting of helpful and harmful deviations as consistent with cost-causation principles," the group said. "However, the commission should allow each RTO to propose specific criteria for determining whether a deviation is helpful or harmful and should recognize that in certain circumstances, a deviation's 'helpfulness' or 'harmfulness' may be difficult to establish."

Most commenters, however, expressed "broad" support for the transparency proposal. The lone dissenter was CAISO, who argued that its existing reporting provides enough transparency and that the new requirements — specifically the deadlines for filing the new reports — would be overly burdensome.

FERC disagreed that CAISO was sufficiently transparent. The ISO aggregates uplift data to its 10 local capacity requirement areas and reports daily total uplift costs for each month by market and type of cost. (See graph on previous page.) It also reports the daily aggregated megawatt-hours of "exceptional dispatches." But it does not specify which of those resulted from operator-initiated commitments.

To address CAISO's concerns, the commission said it would consider extending the filing deadline for the monthly zonal report (20 days after the end of the month) if the ISO can show in its compliance filing that 20 days is not enough time. FERC also extended the deadline for the monthly resource-specific report from 20 days after month-end to 90.

Several commenters argued that resource-specific uplift data should only be obtainable through a password-protected page on the grid operators' websites, an idea FERC rejected. "Providing data only to certain market participants does not achieve the goals of this final rule," the commission said. "Transparency into resource-specific uplift payments can highlight potential instances of gaming and collusion for other market participants, and allow them to advocate for solutions and call attention to such issues more quickly and efficiently."

FERC & Federal News

FERC Whipsawed over Pipeline Policy in House Hearing

By Rich Heidorn Jr.

WASHINGTON — Congress will be watching FERC's review of its policy on licensing natural gas pipelines very closely if the commission's appearance before the House Energy Subcommittee last week is any indication.

Any changes FERC makes are unlikely to please all members, however.

At a hearing attended by all five FERC commissioners, both Republican and Democratic representatives complained that the commission has been too willing to approve pipeline projects and insensitive to landowners in their paths. Others, however, said the commission must speed up its approval process.

All five FERC commissioners testified before the House Energy Subcommittee on April 17. | © *RTO Insider*

Energy and Commerce Committee Chairman Greg Walden (R-Ore.) said he hopes the commission's review of its 1999 policy statement on certifying new interstate pipelines, announced in December, will "result in more efficient and timely decisions." (See related story, *FERC Outlines Gas Pipeline Rule Review*, p.??.)

Walden cited reports that New England relied on two LNG shipments from Russia to get through the winter, fuming: "While cross-border trade with our neighbors in Canada and Mexico may be a win-win, we should never have to be reliant on the Russians for imports again."

Speaking next, Rep. Frank Pallone (D-N.J.), the committee's ranking member, said that he is concerned that ratepayers will be

Continued on page 33

Gas Dominates, Again, in FERC State of the Markets Report

Continued from page 31

rose from 0.63 Bcfd to 2.19 Bcfd, a 248% increase," according to the report. Total exports to Mexico, the U.S.' biggest LNG customer, increased by 0.5 Bcfd to an average 4.2 Bcfd for the year, aided by several new cross-border pipelines.

Gas producers also found new markets within the U.S. About 12 billion Bcfd and 773 miles of new pipeline capacity went into service last year, most of it in the Marcellus and Utica shales. "New pipeline capacity out of the Marcellus and Utica shale plays allowed producers to meet demand in previously inaccessible markets," the report says. "These shale plays demonstrated the largest U.S. natural gas production growth in 2017, with a 10.3% year-over-year increase for a total production of 22.1 Bcfd by the end of 2017." Total U.S. gas production rose 1.0%, averaging 73.6 Bcfd.

One of the only metrics to fall significantly was storage inventory. 2017 saw the third lowest weekly storage injection rate since 2010, while the end-of-year cold snap led to the largest withdrawal in history, 359 Bcf. The large winter withdrawals also led to the lowest end-of-winter storage level since 2014: 1.35 Tcf on April 5, 2018.

Commissioners Neil Chatterjee and Robert Powelson both noted the prevalence of gas in the report, focusing their comments on the importance of fuel security and gas-electric coordination to grid reliability.

"Staff's report indicates that at the beginning of last year, fuel security was already a particular concern within New England and Southern California because of limited natural gas transportation and storage infrastructure, and that by last winter, those concerns had grown into real anxiety," Chatterjee said. Noting the cold snap in the East and pipeline outages in California, "I look back at 2017 as the year of close calls that underscore the importance of examining fuel-security issues," he said.

"The analytics … in today's report are really a testimony to the benefits of organized markets and what they do in terms of providing reliability," Powelson said.

He said he was concerned about the phaseout of the Aliso Canyon storage facility in California, noting the state's aggressive renewable portfolio standard, the closure of several nuclear plants there and, in what he called "the "who-would-have-thunk-it moment," commission-approved reliability-must-run contracts for gas units in CAISO. He called these, along with the high prices in New England, "alarming situations."

The report was released right after FERC issued a Notice of Inquiry to review its 1999 policy statement on natural gas pipelines. (See related story, *FERC Outlines Gas Pipeline Rule Review*.)

FERC & FEDERAL NEWS

FERC Outlines Gas Pipeline Rule Review

By Rich Heidorn Jr.

FERC will open a 60-day comment period on potential changes to its policy statement on the permitting of natural gas pipelines, acknowledging that it may have to reconsider how it balances project benefits against adverse consequences in light of the shale gas revolution, global warming concerns and other changes since it last considered the issue in 1999.

All five commissioners said Thursday they welcomed the Notice of Inquiry (PL18-1), which FERC Chairman Kevin McIntyre had promised at his first meeting in December. (See *FERC to Review Gas Pipeline Approval Process*.)

But given the increasing contentiousness over pipeline expansions, it's unlikely the commission will find consensus on all issues on which the NOI seeks comment. (See *FERC Whipsawed on Pipeline Policy in House Hearing*.)

Flashpoints

The biggest flashpoint may be the debate over how the commission evaluates the greenhouse gas impacts of new pipelines under the Natural Gas Act (NGA) and National Environmental Policy Act (NEPA). The NOI also noted "increased concerns" by landowners and communities affected by proposed projects as the total miles of interstate pipelines approved by the commission annually hit a peak of 2,739 miles last year.

Another point of contention could be calls for speedier pipeline approvals. The NOI says the commission "is committed to carrying out" President Trump's executive order 13807, which calls for completion of all federal environmental reviews and permitting processes for infrastructure projects within two years.

"The commission's aim in this proceeding is the same as in the policy statement: 'to appropriately consider the enhancement of competitive transportation alternatives, the possibility of over building, the avoidance of unnecessary disruption of the environment and the unneeded exercise of eminent domain,'" FERC said.

McIntyre said the commission's issuance of the NOI does not mean FERC will ultimately change its current procedures. He said it will apply the current rules to pending applications on a case-by-case basis during the inquiry. "The commission will consider only generic issues and will not consider any comments that refer to open, contested commission proceedings," the NOI warned.

1999 Policy Statement

The 1999 policy statement followed moves to reduce regulation and increase competition in the industry under the Natural Gas Policy Act of 1978 and FERC Order 436, which allowed local distribution companies and industrial customers to buy gas directly from producers or merchants and transport their gas on interstate pipelines.

The policy statement said the commission will consider whether a proposed project's anticipated public benefits outweigh its adverse effects on economic interests. If so, the commission then analyzes the project's environmental impacts in reaching a conclusion on whether a project is required by the public convenience and necessity.

Four Topics of Inquiry

The commission asked for comments on four topics:

- The reliance on precedent agreements to demonstrate project need, and how contracts with pipeline affiliates should be treated (e.g., "Should the commission examine whether the proposed project meets market demand, enhances resilience or reliability, promotes competition among natural gas companies, or enhances the functioning of gas markets?");
- Landowner interests and the use of eminent domain (e.g., "Should applicants take additional measures to minimize the use of eminent domain?");
- The evaluation of alternatives and environmental effects under NEPA and the NGA (e.g., "Are there any environmental impacts that the commission does not currently consider in its cumulative impact analysis that could be captured with a broader regional evaluation?"); and
- The efficiency and effectiveness of the commission's certificate processes (e.g., "Should certain aspects of the commission's application review process (i.e., pre-filing, post-filing and post-order-issuance) be shortened, performed concurrently with other activities or eliminated to make the overall process more efficient?").

Comments will be due within 60 days of the publication of the NOI in the *Federal Register*.

FERC Whipsawed over Pipeline Policy in House Hearing

Continued from page 32

billed for unneeded projects and that landowners have no way to fight them. He called on the commission to conduct regional reviews of pipeline needs rather than evaluating each project individually.

Rep. Leonard Lance (R-N.J.), who is not a member of the subcommittee, attended the hearing nonetheless to tell the commission of his complaints over its approval in January of the PennEast pipeline project in Pennsylvania and New Jersey. The New Jersey attorney general went to court last month to prevent the project developer from condemning more than 20 properties acquired under open-space and farmland preservation programs.

Frank Pallone | © *RTO Insider*

Lance also questioned whether FERC was conducting "robust economic analysis" in using contracts with pipeline affiliates as evidence of a project's need.

"It's my considered judgment that this [project] is not in the best interests of the

Continued on page 34

FERC & Federal News

FERC Order Seeks to Reduce Time, Uncertainty on Interconnections

By Rich Heidorn Jr.

FERC on Thursday ordered new rules to increase the transparency and timeliness of the generator interconnection process (RM17-8).

The order adopts all but four of 14 potential rule changes in the commission's December 2016 Notice of Proposed Rulemaking revising the *pro forma* large generator interconnection procedures and large generator interconnection agreement (LGIA). (See *FERC Proposes Changes to Interconnection Rules*.)

The rulemaking, which was prompted by a complaint by the American Wind Energy Association, applies to generators larger than 20 MW.

Commission staff said the revisions acknowledge the inefficiencies that have resulted from changes to the generation industry since the commission issued the *pro forma* interconnection procedures and agreement in 2003 (Order 2003).

"These inefficiencies include backlogs in interconnection queues, long timelines to process interconnection requests and late-stage withdrawals of interconnection requests that can lead to cascading interconnection restudies, which can lead to even more withdrawals," staff said in a presentation at the commission's open meeting.

It also seeks to address transmission providers' concerns that the interconnection study process has become difficult to manage because they have been flooded with requests for new facilities that have little chance of reaching commercial operation.

The final rule removes a limitation on an interconnection customer's ability to construct interconnection facilities and standalone network upgrades and requires transmission providers to improve their dispute resolution procedures.

To improve transparency and efficiency, the rule:

- requires transmission providers to make public their methods for determining contingent facilities and to list the processes and assumptions used for network models employed in interconnection studies;
- revises the definition of "generating facility" to explicitly include electric storage;
- sets requirements for reporting on aggregate interconnection study performance;
- allows an interconnection customer to request a level of service lower than its generating facility capacity;
- requires transmission providers to allow provisional interconnection agreements that offer limited operation of a generator before completing the interconnection process;
- requires transmission providers to offer the use of surplus interconnection service; and
- requires transmission providers to consider changes in an interconnection customer's proposed technology that occur during the interconnection process to determine if they constitute a material modification.

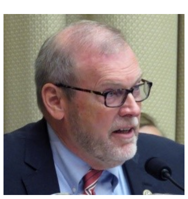
"The transparency reforms make information more timely and accessible to transmission customers, thereby potentially reducing the number of interconnection requests for projects that are unlikely to reach commercial operation," staff said. "The efficiency and enhancement reforms facilitate the use of existing interconnection, mitigate the likelihood of unnecessary upgrades and related costs, provide paths to bring generation online more quickly, and allow for the incorporation of techno-

Continued on page 35

FERC Whipsawed over Pipeline Policy in House Hearing

Continued from page 33

United States and certainly not in the best interests of New Jersey," Lance said.


Morgan Griffith | *© RTO Insider*

Rep. Morgan Griffith (R-Va.) said "the frustration level in Virginia is so high" over FERC's pipeline reviews that he has teamed up with Democratic Sen. Tim Kaine (D-Va.) on legislation he said would increase the transparency of FERC's licensing process (H.R. 2893, S. 1314). "Tim Kaine and I don't generally agree," he noted.

Griffith complained that surveyors for a pipeline appeared unannounced in his district recently and said the commission had rejected his request for additional public hearings to make travel to the sessions less burdensome for his constituents. He suggested putting two or more pipelines into the same corridor to minimize impacts on landowners. "FERC can do a better job," he said.

LNG Exports

Rep. Pete Olson (R-Texas) said some Gulf Coast LNG projects have fallen behind schedule because of delays in receiving FERC approvals. "I've heard rumors that FERC has only six to eight employees [responsible] for approving these … permits. I've heard you actually approached the [Department of Energy] for new [employees] to help out with the backlog of approving LNG permits," he said. "Is that true?"

McIntyre did not answer the LNG staffing question but acknowledged the commission is planning to add staff to the Office of Energy Projects to process LNG and pipeline applications.

"It's consuming an enormous amount of attention and manpower within the agency," he said. "If there's any suggestion that we are somehow not giving it our full effort right now, I can assure you that is not the case at all."

The pipeline review was just one of the issues the committee addressed during the three-hour hearing, which Walden said was the first with the full commission since 2015. Also discussed were the commission's grid resilience inquiry, the financial struggles of coal and nuclear generation, the Public Utility Regulatory Policies Act, cybersecurity and its technical conference on distributed energy resources. (See related story, *Ready to Act on DERs, FERC Tells Congress*, p.??.)

FERC & FEDERAL NEWS

FERC Finalizes Cyber Controls on Portable Devices

By Rich Heidorn Jr.

FERC on Thursday approved rules to prevent malware from infecting "low impact" computer systems through transient electronic devices such as laptops and thumb drives (RM17-11, Order 843).

The order approves a requirement outlined in the commission's October Notice of Proposed Rulemaking directing NERC to modify reliability standard CIP-003-7 to mitigate the risk of malicious code that could result from third-party devices that frequently connect to and disconnect from low-impact systems. (See *FERC Seeks Cyber Controls on Portable Devices; Sets GMD Plans*.)

The commission reiterated the concerns it raised in the NOPR that the NERC standard "lacks a clear requirement to mitigate the risk of malicious code" that could result from third-party transient devices. "Accordingly, we direct NERC to develop a modification to the reliability standard to provide the needed clarity. Such modification will better ensure that registered entities clearly understand their mitigation obligations and, thus, improve individual entity mitigation plans," the commission said.

However, the commission declined to adopt a proposal requiring NERC to "provide clear, objective criteria for electronic access controls" for low-impact systems. NERC tiers its cybersecurity requirements based on classifications of high-, medium- and low-impact Bulk Electric System (BES) cyber systems.

The commission said comments from NERC and others convinced it that the reliability standard already "provides a clear security objective that establishes compliance expectations."

Instead, FERC ordered NERC to conduct a study within 18 months to assess the implementation of the standard to determine whether the electronic access controls adopted by responsible entities "provide adequate security." The study was proposed in a joint filing by the American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, identified in the order as "trade associations."

Reversal

NERC said that the standard requires responsible entities to "document the necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access."

The trade associations, Electric Consumers Resource Council (ELCON) and Transmission Access Policy Study Group said the proposal would be burdensome and ineffective. While it "appreciates the value establishing more tangible criteria for adequate low-impact BES cyber system controls … the additional requirements that the commission proposes would do nothing to harden a low-impact facility against the rapid evolution in cyber warfare," ELCON said.

The trade associations urged a risk-based approach to allow responsible entities to focus their resources on assets that have a higher impact on reliability.

"Given NERC's statements, we believe that there will be adequate measures to assess compliance with reliability standard CIP-003-7," FERC concluded. "We expect responsible entities to be able to provide a technically sound explanation as to how their electronic access controls meet the security objective."

Mitigation of Malicious Code

The trade associations and ELCON also opposed the NOPR's proposal to require responsible entities to prevent malicious code from entering their systems via transient electronic devices used by contractors and other third parties. The trade groups said risk mitigation is implicitly required under Section 5 of the standard.

But FERC said the standard doesn't go far enough. "While commenters agree that, at least implicitly, the mitigation of malicious code is an obligation, the lack of a clear requirement could lead to confusion in both the development of a compliance plan and in the implementation of a compliance plan," the commission said. "In addition, although NERC contends that the proposed directive may not be necessary, NERC agrees that modifying reliability standard CIP-003-7 to address the mitigation of malicious code explicitly could clarify compliance obligations."

FERC said the new standard also will improve reliability by requiring responsible entities to have a policy for declaring and responding to "exceptional circumstances" — defined by NERC as a natural disaster, civil unrest or a situation that threatens to impact BES reliability or presents a risk of injury or death.

FERC Order Seeks to Reduce Time, Uncertainty on Interconnections

Continued from page 34

logical advancements into an interconnection request."

Stakeholder comments persuaded FERC not to adopt four other rule changes requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information and the modeling of electric storage.

The commission also took no action on two other issues on which the NOPR sought comment but for which no proposals were made: cost caps for network upgrades and affected-system coordination, the latter of which was the subject of a two-day technical conference in early April. (See *Developers, Tx Providers Seek Direction on 'Affected Systems'* and *Renewable Gens Face Off with RTOs at Seams Tech Conference*.)

The American Council on Renewable Energy (ACORE) issued a statement praising the order. "While the reforms cover interconnection for all types of energy generators, we believe the final rule is an important recognition of a fundamental shift in the U.S. electric sector as we continue to diversify our electricity supply. Going forward, we are optimistic the rule will improve and expedite critical interconnection procedures for solar, wind and other renewable technologies, while also expanding access to energy storage resources."

FirstEnergy Announces Mixed Earnings, Plan for FES Bankruptcy

By Rory D. Sweeney

FirstEnergy announced mixed first-quarter earnings Monday, along with a potential path to exit the bankruptcy of its merchant subsidiaries.

The "agreement in principle" with two groups of "key" creditors that represent most of the outstanding debts for FirstEnergy Solutions (FES) includes $225 million in cash and a tax note of $628 million due before 2020, according to a company financial disclosure filed with the U.S. Securities and Exchange Commission.

Additionally, a $787 million unsecured claim would be allowed for creditors of the company's Bruce Mansfield coal-fired plant in Pennsylvania, where a fire damaged two of the facility's three coal-fired units earlier this year and two workers died from exposure to hydrogen sulfide gas in August, according to company filings. Four other employees were injured. The claim would be allowed against FES and its subsidiaries, FirstEnergy Generation and FirstEnergy Nuclear Generation.

Although FirstEnergy's Allegheny Energy Supply (AE Supply) subsidiary hasn't filed for bankruptcy, the agreement would also transfer to creditors its ownership of the Pleasants coal-fired plant, for which it hasn't found a buyer. (See FirstEnergy Shutting down Unsold Coal Plant.) AE Supply sold off its natural gas and pumped hydro generation assets last year. (See FirstEnergy Selling Merchant Fleet Despite NOPR.)

Earnings

The agreement came as FirstEnergy also reported unadjusted first-quarter earnings of $1.2 billion ($2.54/diluted share), which improved from $205 million ($0.46/share) during the first quarter last year. Operating earnings of 67 cents/share improved from 52 cents during the same period in 2017 but missed expectations by 1 cent. Revenue increased to approximately $3 billion compared with $2.9 billion a year ago but remained several hundred million dollars below analysts' expectations.

The company attributed the improved performance to shedding its beleaguered merchant generation fleet.

"Today, we are pleased to report strong earnings that represent FirstEnergy as a fully regulated company," CEO Charles E. Jones said.

The company raised its forecast range for unadjusted earnings for the year to $3.61 to $3.91/share, but it announced a gloomier forecast for next quarter. Unadjusted earnings are expected to drop to no more than 4 cents/share and could fall to a loss of 6 cents. Operating earnings are expected in the range of 47 to 57 cents/share.

Agreement Conditions

Company executives clarified several of the agreement's points during a conference call on Monday to discuss the quarterly earnings with financial analysts.

One of the agreement's conditions allows that if more than 60% of unsecured claims are recovered, FirstEnergy would receive 50% of any additional recovery. Jones acknowledged that such a situation would include any federal bailouts, such as those the company has requested through the Department of Energy, but emphasized that his interest is in keeping the plants

Continued on page 37

CenterPoint Energy to Acquire Vectren in $6B Deal

By Amanda Durish Cook

Houston-based utility CenterPoint Energy announced Monday that it will acquire Vectren in an approximately $6 billion deal expected to close in the first quarter of 2019.

CenterPoint will pay Vectren shareholders $72 for each share of Vectren common stock — a $6.45 premium to Friday's closing price — and assume all outstanding Vectren net debt. Hours after the announcement, Vectren closed Monday at $70.31 while CenterPoint ended the day at $25.94/share, down 31 cents.

The merged company will retain the CenterPoint name and its Houston headquarters. CenterPoint will also maintain Vectren's Evansville, Ind., headquarters for the company's natural gas utilities and Indiana electric operation. The company will serve more than 7 million customers, operate electric and natural gas delivery operations in eight states and hold about $29 billion in assets.

The merger agreement has been approved unanimously by the boards of both companies, though the deal still requires approvals from Vectren shareholders, FERC, the Federal Communications Commission and regulators in Indiana and Ohio. CenterPoint said it expects to maintain a 5% to 7% annual earnings per share growth target in 2019 and 2020, excluding any one-time charges related to the merger. Both CEOs said the move will benefit their companies.

"By combining our two highly complementary companies, we are creating an energy delivery, infrastructure and services leader that will drive value for our shareholders and customers, while enhancing growth opportunities for our businesses," CenterPoint CEO Scott Prochazka said in a statement.

"With CenterPoint Energy, we've found the right partner to begin the next chapter for Vectren and our family of companies. … Together, we will be a stronger, more competitive company that will be well-positioned to continue to provide value for our stakeholders in the years to come," said Vectren CEO Carl Chapman.

Prochazka will remain CEO of the combined company. All other executive positions will be announced "prior to or in conjunction with the closing of the merger," the companies said. CenterPoint said it will establish an executive position in Evansville, Ind., to handle natural gas utility operations and a chief business officer for Vectren's electric business to directly report to the CenterPoint CEO and "spearhead southwestern Indiana's electric grid modernization and generation transition initiatives recently underway."

Earlier this year, Vectren announced it would build an 800- to 900-MW, $900 million natural gas plant in southwestern Indiana and a 50-MW, $75 million solar farm about 60 miles from the gas plant site. The new generation would replace three of Vectren's coal-fired plants. The proposed gas plant still requires approval from the Indiana Utility Regulatory Commission. The company is also set to complete construction this year on two solar farms near Evansville that will produce 4 MW combined.

Prochazka and Chapman told the Evansville *Courier & Press* that they expect the merger will reduce Vectren's 5,500-person staff but that it was too soon to say where, or how deep, the cuts will be.

The company provides electricity to about 145,000 customers in Indiana and natural gas to more than 1 million customers in Indiana and Ohio. Vectren also owns non-utility businesses Vectren Infrastructure Services Corp., which provides underground pipeline construction, repair and replacement services, and Vectren Energy Services Corp., which offers performance contracting services and renewable energy project development. CenterPoint said it intends to continue operating both companies.

CenterPoint currently delivers electricity to more than 2.4 million customers in the greater Houston area and serves another 3.4 million customers with natural gas operations in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The company employs nearly 8,000 people.

FirstEnergy Announces Mixed Earnings, Plan for FES Bankruptcy

Continued from page 36

open for the well-being of the communities in which they're operating.

"We're highly motivated to get support for those generating assets because it would be a mistake for our country for them to close," he said. "I'm going to keep fighting for support for those plants, because it's the right thing to do. If it gets to the point where it exceeds the threshold that we've got in this agreement with creditors, then, yes, we would share some of that, but that's not why we're doing it."

In exchange for assistance from FirstEnergy during restructuring, the settlement would release the parent company from all claims,

Pleasants coal-fired plant

including decommissioning obligations for any of the nuclear plants if they are closed as the company has announced, Jones confirmed. (See *FES Seeks Bankruptcy, DOE Emergency Order*.)

FirstEnergy would waive some intercompany claims and maintain all previously announced guarantees, including pension obligations for FES employees. Creditors agreed to "use their best efforts" to get remaining creditors to join the settlement by June 15.

The agreement must receive sign-off from a federal bankruptcy court in Ohio, along with the boards of directors for FirstEnergy and its subsidiaries, including FirstEnergy Nuclear Operating Co. (FENOC).

FES and FENOC voluntarily filed for Chapter 11 bankruptcy on March 31. FES is FirstEnergy's merchant generation and retail marketing subsidiary, while FENOC operates FES' three nuclear plants. The decision, while expected for some time, is nonetheless creating ripples of uncertainty throughout the industry. (See *FES Bankruptcy Creating Additional Uncertainty*.)

Company Briefs

AEP Files Settlement with FERC Cutting Tx ROE

American Electric Power said April 19 that it filed with FERC last month a settlement agreement concerning the return on equity it can earn on transmission investments in its eastern operating and transmission companies.

The agreement, which must be approved by FERC, reduces AEP's base ROE to 9.85% from 10.99%, effective from the start of this year. That would give AEP a total ROE of 10.35% because of an adder it receives as an RTO member.

The agreement also places the cap on equity for AEP's eastern transmission projects at 55%. Additionally, it requires AEP to make a one-time refund of $50 million to transmission customers for periods prior to 2018 that will be credited to them in this quarter.

More: *American Electric Power*

FERC Approves PacifiCorp Ancillary Service Rates

FERC last week approved an uncontested settlement agreement regarding PacifiCorp's rates for regulation and frequency control service (ER17-219). The company filed the agreement on Jan. 31, which also set rates for generator spinning reserve service.

Parties to the settlement included Utah Associated Municipal Power Systems, Deseret Generation and Transmission Cooperative, Utah Municipal Power Agency, Bonneville Power Administration, Avangrid Renewables and NextEra Energy Resources. It establishes the framework for self-supply or third-party supply of the ancillary services over two periods: July 13, 2017-Dec. 31, 2017, and a separate period beginning Jan. 1, 2018.

The March 5 certification of the agreement by settlement Judge Steven Glazer lists the rates for the services. Commission staff submitted comments in support of the agreement, saying it implements significantly reduced rates.

Evans Replacing Beattie As Southern CFO

Southern Co. said April 17 that Andrew Evans will replace the retiring Art Beattie as executive vice president and chief financial officer.

Evans

Kimberly Greene was picked to succeed Evans as chairman, president and CEO of Southern Company Gas, and Stan Connally Jr. will assume Greene's responsibilities as executive vice president of operations for Southern Co. while continuing to serve as chairman, president and CEO of Gulf Power.

More: *Atlanta Business Chronicle*

Cross Texas Transmission Places New Line in Service

Cross Texas Transmission said April 19 it placed the Limestone to Gibbons Creek transmission line into service earlier in the week.

The 68-mile, double-circuit 345-kV transmission line, which is the northern portion of the Houston Import Project, runs from the Limestone Substation in Limestone County to the Gibbons Creek Substation in Grimes County.

The Public Utility Commission of Texas issued a final order approving the transmission line in January 2016 after ERCOT said it was needed by June 2018 to ensure reliability and reduce congestion.

More: *Cross Texas Transmission*

Xcel Gets First-of-kind Permission to Use Drones

Xcel Energy said April 18 that the Federal Aviation Administration has given it permission to be the first utility to fly unmanned aircraft beyond their operators' line of sight.

The company said that, starting this summer, it will routinely operate drones beyond their operators' line of sight to inspect transmission lines within a designated area roughly 20 miles north of Denver International Airport.

The operators, who are licensed pilots, will remotely operate an unmanned helicopter that weighs less than 55 pounds and use command-and-control technology to ensure it operates safely.

More: *Xcel Energy*

SunPower Agrees to Buy SolarWorld

SunPower has agreed to buy SolarWorld Americas for an undisclosed sum, the two solar equipment manufacturers said April 18.

The deal would add 430 MW of cell capacity and 550 MW of module capacity to SunPower's operations, putting the company in position to rival First Solar as the largest U.S. maker of solar modules.

In addition to U.S. regulators, the deal must be approved by those in Germany. That's because SolarWorld Americas is a subsidiary of German SolarWorld AG, even though it's one of the two U.S. companies that sought the tariffs against imported solar products that the Trump administration imposed in February.

In comments it filed on the tariffs on April 16, SolarWorld supported SunPower's request to be excluded from the tariffs. SunPower is based in San Jose, Calif., but most of its manufacturing is in the Philippines and Mexico and French oil giant Total has a majority stake in it.

More: *SunPower; San Francisco Chronicle; Greentech Media; Reuters*

OVEC Requests Delay In PJM Integration

The Ohio Valley Electric Corp. has requested a delay in its integration into PJM's system that was planned for June 1. The request was announced April 17 through PJM's stakeholder communications and noted that the RTO and OVEC filed the previous day with FERC to delay the integration "to an unspecified date."

PJM officials alluded to the potential for a delay at the April Market Implementation Committee meeting during a discussion of FirstEnergy Solutions' recent bankruptcy announcement. PJM CFO Suzanne Daugherty told attendees that the RTO was prepared to integrate OVEC on June 1 but would also accommodate any delay requests. (See "FES Bankruptcy," *PJM Market Implementation Committee Briefs: April 4, 2018*.)

Despite stakeholder concerns, PJM determined in November that OVEC meets the membership requirements outlined in the Operating Agreement and that its

Continued on page 39

COMPANY BRIEFS

Continued from page 38

integration will not cause any reliability challenges. FERC approved the integration without comment on Feb. 13. OVEC's system includes 705 miles of 345-kV transmission lines and 2,200 MW of capacity from two coal-fired generation plants.

FERC Grants Marketers Delay On Show Cause Order

FERC last week granted the North American Energy Markets Association (NAEMA) a 120-day extension to respond to the commission's March order threatening to revoke the group's capacity and energy tariff (ER18-676).

NAEMA, which claims about 150 members with 500,000 MW of generating capacity, developed the power and gas tariff with the International Energy Credit Association.

The group said the tariff, filed in January, was like the 2003 tariff but was updated to reflect current industry preferences for contract language and products. It intended to leave the existing tariff in place with the new one available for companies that choose to use it. But the commission said March 19 that the tariffs should not be on file with it because NAEMA is not a jurisdictional public utility. (See *Second Thoughts: FERC May Revoke Marketers' Tariff*.)

The commission said NAEMA's response to the show cause order is due on Aug. 16. It denied the group's request for appointment of a non-decisional commission staff member that it could consult with, saying, "We are not persuaded that such an appointment would be beneficial."

NH Site Committee Schedules Northern Pass Hearing

The New Hampshire Site Evaluation Committee has scheduled a hearing for May 24 on Eversource's bid to have it reconsider its decision denying the utility and Hydro-Quebec permission to build the Northern Pass transmission project.

The project, which would bring hydropower from Canada to the New England grid, had been selected by Massachusetts as the winner of the state's clean power solicitation in January, but the state revoked that decision last month after the Site Evaluation Committee's decision. (See *Massachusetts Bids Adieu to Northern Pass*.)

More: *New Hampshire Public Radio*

Bie Replaces Bemis As NYISO Board Chair

Bie

NYISO's Board of Directors said April 17 that Ave M. Bie has been named chair, replacing Michael Bemis, whose term as chair ended April 17.

Robert Hiney will replace Bie as vice chair. Bemis will continue to serve as a member of the board.

Bie joined the board in April 2009. She chaired the Governance Committee from 2011 through 2016 and has been chair of the Commerce and Compensation Committee since 2016. She became the board's vice chair last year.

More: *NYISO*

FEDERAL BRIEFS

Trump Admin Thinking of Using Defense Act to Support Coal

FERC Chair Kevin McIntyre speaks to reporters after Thursday's open meeting. | © *RTO Insider*

Trump administration officials are considering using the 68-year-old Defense Production Act to keep financially struggling coal and nuclear power plants operating, Bloomberg reported, citing four people familiar with the deliberations who asked for anonymity to discuss them.

The act was used by President Harry Truman during the Korean War to cap wages in and impose price controls on the steel industry. It also was used in 2001 to keep natural gas flowing to power generators in California to avoid blackouts in the state.

Asked about the Bloomberg story at FERC's open meeting on Thursday, Chairman Kevin McIntyre said, "Despite being a proud member of the Energy Bar, I confess I haven't had a chance to pull that statute up yet and review what it actually does and says." He noted FirstEnergy's pending request for its plants before the Department of Energy under Federal Power Act Section 202c, which he said he assumed was a "comparable" provision, relating to wartime or other emergency situations.

Asked whether he thought there was such an emergency, McIntyre said that was a question that "I entirely trust the secretary of energy and his team to address."

More: *Bloomberg Politics*

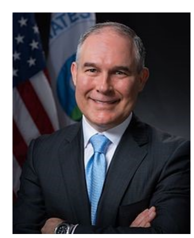
DOE to Fund 9 Early-stage Solar Electronics Projects

The Department of Energy said April 18 it has selected nine projects designed to advance early-stage solar power electronics technologies to receive up to $20 million in funding.

Each project's sponsor must provide 20% of its project's cost. The projects will last up to three years.

More: *Department of Energy*

Democratic Lawmakers, Multiple Groups Call for Pruitt's Departure



Pruitt

A group of 131 U.S. representatives and 39 U.S. senators, all Democrats, signed a resolution introduced April 18 calling on EPA Administrator Scott Pruitt to resign.

The resolution highlighted concerns about Pruitt's use of taxpayer money, "dramatic" budget cuts to EPA and waivers given to employees to do work outside the agency.

Also on April 18, a coalition of labor and civil rights organizations joined environ-

Continued on page 40

Federal Briefs

Continued from page 39

mental groups to place an ad in three newspapers calling for Pruitt "to resign or be removed."

The calls for Pruitt to leave came the same day that Office of Management and Budget Director Mick Mulvaney said his office was opening an investigation to see if EPA broke the law when it spent $43,000 on a secure phone booth for Pruitt without notifying Congress first.

More: *The Hill*; *The Washington Post*; *ABC News*; *Bloomberg Politics*

House Subcommittee Approves DOE Cybersecurity Bills

The House Energy Subcommittee on April 18 approved four bills to bolster the Department of Energy's cybersecurity efforts in response to revelations of Russian cyberattacks targeting natural gas pipeline operators and the power grid.

The bills would require Energy Secretary Rick Perry to establish a program to boost the physical and cybersecurity of pipelines and LNG facilities; make the leader of the department's emergency response and cybersecurity efforts an assistant secretary; establish a program to help private utilities find and use strongly cybersecure products; and enhance public-private partnerships to ensure that electric utilities are secure.

The bills now advance to the full House Energy and Commerce Committee for a vote.

More: *The Hill*

TVA-area Lawmakers Urge Trump not to Sell Tx Assets

Fifteen members of Congress from the Tennessee Valley on April 18 wrote a letter urging President Trump to abandon his proposal to sell the Tennessee Valley Authority's transmission assets.

The letter was signed by Tennessee's entire congressional delegation plus four lawmakers from Kentucky and Alabama.

In the letter, they warned that splitting up TVA's generation and transmission assets could threaten the low-cost model of the federal utility, which was created in 1933 to serve the seven-state Tennessee Valley.

More: *Times Free Press*

Wind Provided 6.3% of US Power Last Year

Wind provided a record 6.3% of U.S. electricity last year, according to a report released April 17 by the American Wind Energy Association.

The "U.S. Wind Industry Annual Market Report 2017" said wind now supplies more than 30% of the power in four states: Iowa, Kansas, Oklahoma and South Dakota.

New Mexico, where the report was released, had the biggest capacity growth of all the states in percentage terms last year. Its wind power capacity grew by 570 MW, or 51%. The country's wind power capacity grew 7,017 MW, or 9%, to 88,973 MW last year.

More: *American Wind Energy Association*

DOE to Provide up to $105.5M for Solar Projects

Energy Secretary Rick Perry said April 17 that the Department of Energy's Solar Energy Technologies Office (SETO) will provide up to $105.5 million to fund about 70 projects to advance both solar photovoltaic and concentrating solar thermal power technologies, as well as facilitate their secure integration into the grid.

SETO plans to provide up to $46 million to fund about 14 projects involving advanced solar systems integration technologies; up to $24 million to fund about 21 projects involving concentrating solar power research and development; up to $27 million to fund about 28 projects involving PV research and development; and up to $8.5 million to fund four projects that involve improving and expanding the solar industry through workforce initiative.

More: *Department of Energy*

State Briefs

REGIONAL

Pa. PUC Chair to Head NARUC Infrastructure Committee


Brown

The National Association of Regulatory Utility Commissioners said April 19 that Pennsylvania Public Utility Commission Chair Gladys Brown has been chosen to lead its Committee on Critical Infrastructure.

Brown succeeds Rick Mroz, the former head of the New Jersey Board of Public Utilities.

Committee chairs are appointed by NARUC's president for one-year terms and may be reappointed for up to three consecutive terms.

More: *National Association of Regulatory Utility Commissioners*

RGGI Provided $1.4 Billion in Economic Benefits in Past 3 Years

The nine Northeast states that belong to the Regional Greenhouse Gas Initiative have received $1.4 billion in economic benefits over the past three years because of how they invested proceeds from its cap-and-trade program, according to a report released April 17 by the Analysis Group.

The report also found that the RGGI has neither undermined grid reliability nor led to a net increase in electric bills.

New Jersey, which dropped out of the initiative in 2011, cost itself from $62 million to $154 million over the last three years by doing so, one of the report's authors said. New Jersey Gov. Phil Murphy plans to have the state rejoin the RGGI. Virginia also is planning to join.

More: *Inside Climate News*; *Northeast Energy News*

Continued on page 41

State Briefs

Continued from page 40

ARIZONA

Legislature OKs Coal Tax Break To Boost Plant's Sale Chances

The Senate on April 19 voted 18-12 to approve legislation that would exempt coal bought by the Navajo Generating Station from the state sales tax to try make the plant more attractive to potential buyers. The bill was previously passed by the House of Representatives.

The tax would go into effect if the plant, which is scheduled to close at the end of next year, is sold. Peabody Energy's Kayenta Mine supplies coal to the plant.

The tax would cost the state $12 million a year, but the Legislature says if the plant closes the state will lose the money anyway.

More: *The Associated Press*

ARKANSAS

Executive Director, Staffer Leaving PSC

John Bethel said April 18 that he's retiring after 18 years as the Public Service Commission's executive director and that Matthew Klucher, one of its top experts on rate issues, is leaving the commission in an unrelated move.

Bethel said he's retiring to pursue other interests. He joined the commission's staff in 1988 and became its executive director in 2000.

Klucher, he said, had resigned "to take another position."

More: *Arkansas Business*; *Talk Business & Politics*

CONNECTICUT

PURA Reduces Eversource Rate Increase to $124.7M

The Public Utilities Regulatory Authority on April 18 granted Eversource Energy a $124.7 million revenue increase phased in over three years, roughly $212 million less than the nearly $337 million the utility had asked for.

PURA said the decision means the monthly bill of an average residential customer will increase approximately $5.40 in the first year of the settlement and by smaller amounts in the following two years.

Eversource's original request was reduced to account for the savings the company will realize from the Tax Cut and Jobs Act and as a result of a January settlement agreement that reduced its revenue requirements related to depreciation expense, return on equity and other factors.

More: *Hartford Business Journal*

LOUISIANA

PSC Approves Entergy Rate Cut to Pass on Tax Savings

The Public Service Commission on April 18 approved a plan to reduce Entergy Louisiana's rates in two stages to account for the lower federal corporate tax rate the company is paying due to the Tax Cut and Jobs Act.

Entergy Louisiana saved about $210 million as a result of the act. It will return about $105 million of that to customers from May through December through a rate cut that will reduce the monthly bill of a typical residential customer that uses 1,000 kWh/month by $4.20. It will return the remainder through a rate cut that will reduce the monthly bill of a typical residential customer by $2 for four years, starting in September.

The monthly bill of a typical Entergy Louisiana residential customer will drop again in October when the company gets done paying off a loan it took out to pay for infrastructure repair after hurricanes Katrina and Rita. Typical residential customers in the Baton Rouge and Acadiana will see their monthly bills drop $2.55, and customers in the New Orleans suburbs and north Louisiana will see their monthly bills drop $4.15.

More: *The Advocate*

MICHIGAN

PSC Replaces Net Metering with Inflow/Outflow Billing Method

The Public Service Commission on April 18 issued an order approving a residential distributed generation billing mechanism that eventually will replace net metering.

Under the mechanism, the inflow, which is the energy a customer buys from a utility, will be priced at the full retail rate. Meanwhile, the outflow, which is the excess energy the customer sells to the grid, will be credited at the utility's avoided cost in dollars or kilowatt-hours in the next billing period.

Utilities must include their DG inflow/outflow tariff in rate cases filed after June 1. Customers enrolled in a net metering program can remain in it for 10 years.

More: *Public Service Commission*

AG to Sue Company that Damaged ATC Submarine Cables

Attorney General Bill Schuette said April 17 he has sent a letter to VanEnkevort Tug and Barge stating he will bring a civil action against the company for causing the discharge of a hazardous substance when one of its ships dragged an anchor across two submarine transmission cables and natural gas and oil pipelines in the Straits of Mackinac.

The transmission cables, owned by American Transmission Co., were damaged and released an estimated 600 gallons of dielectric fluid into the water. ATC had to shut them down permanently.

The oil and gas pipelines, which run parallel to the transmission cables, are owned by Enbridge Energy and were damaged as well.

More: *MLive*

NEW HAMPSHIRE

New Energy Strategy Recommends Broader Renewable Definition

The first update to the state's 10-year energy strategy since 2014, released April 17 by the Office of Strategic Initiatives, calls for the state to broaden its definition of renewable energy and make siting projects easier.

The update says the state should redefine its renewable energy portfolio to include nuclear power or large-scale hydro from Quebec. "If reducing emissions is a primary objective, then the [renewable portfolio standards] should be redefined to include

Continued on page 42

STATE BRIEFS

Continued from page 41

other zero- or low-carbon resources," the 62-page document says.

It also says the siting process "often highlights tensions between individual or small community interests and collective interests. … Responding to these issues is difficult and requires balancing numerous interests but does not remove the necessity of siting appropriate energy infrastructure to meet New Hampshire needs."

More: *New Hampshire Union Leader*

NEW YORK

State to Use Incentives to Increase EE Savings by 2025

Gov. Andrew Cuomo said April 20 that the state will boost its energy-efficiency efforts by giving commercial and residential building developers and owners, including homeowners, incentives to pursue building improvements to make energy consumption in 2025 185 trillion Btu less than the energy consumption currently forecast for the year.

The state expects the boost will accelerate projected energy-efficiency increases by more than 40% over the next seven years and set it on a path to realizing savings in power consumption of 3% of the sales of its investor-owned utilities in 2025.

More: *Gov. Andrew Cuomo*

PENNSYLVANIA

Senate Unanimously Reconfirms Brown to PUC

The State Senate on April 17 unanimously confirmed Public Utility Commission Chairman Gladys M. Brown to a second five-year term. Brown will continue to serve as the commission's chairman.

Brown was nominated to the commission by then-Gov. Tom Corbett in 2013 and named chairman in 2015 by Gov. Tom Wolf. Her new term will end April 1, 2023.

More: *Pennsylvania Public Utility Commission*

RHODE ISLAND

DPUC Recommends Smaller Rate Hike for National Grid

In a filing with the Public Utilities Commission, the Division of Public Utilities and Carriers has recommended an $11.3 million rate hike for National Grid, rather than the $45.8 million the utility requested.

National Grid's original request last November was for $71.6 million in additional revenue, but after calculating its tax savings from the Tax Cut and Jobs Act, the utility reduced it in January.

National Grid is seeking additional revenue from its 497,000 electric customers and 267,000 gas customers to cover increases in operating costs — including health care, labor and equipment — and investments in cybersecurity.

More: *The Providence Journal*

TEXAS

ERCOT's TAC Cancels April 26 Meeting

ERCOT's Technical Advisory Committee has canceled its April 26 meeting, citing a lack of voting items. TAC Vice Chair Diana Coleman said an email vote is not expected.

The TAC's next regularly scheduled is May 24.

VIRGINIA

Corporation Commission Issues Orders on Rate Reductions, Refunds

The Corporation Commission on April 16 ordered Dominion Energy Virginia and Appalachian Power to make rate reductions to reflect their reduced federal taxes as a result of the Tax Cut and Jobs Act.

Dominion must reduce its rates by $125 million, and Appalachian Power by $50 million, within 30 days of July 1. Additionally, in July, Dominion must issue a $133 million refund to customers as a result of excess earnings it reported for calendar years 2015 and 2016. The company also will issue a $67 million refund in January 2019 that is associated with its 2017 earnings.

More: *State Corporation Commission*

Ready to Act on DERs, FERC Tells Congress

Continued from page 1

we've got enough now to go on to make a determination about what the appropriate steps are."

Commissioner Cheryl LaFleur said there are two "macro issues" to be determined: one financial, the other operational.

She said ensuring that DERs do not receive duplicate payments at the wholesale and retail levels "will require some very specific rules."

LaFleur said the commission got valuable testimony on the second issue: "how the different control centers talk to each other."

"I think one of the big issues we're going to have to think about as a body now is how uniform we make the rules as we put them out as opposed to allowing regional variations," she continued. "Some of the people testified about wanting different regions to go in different directions here. I'm somewhat of the belief that the technology is marching so quickly that we should try to figure out what best practices are now. That's what we'll be debating."

Rep. Gregg Harper (R-Miss.) questioned whether FERC was intruding on state and local regulators. "With the issuance of Order No. 841 and its proposal for the aggregation of DERs for the purpose of participating in wholesale electric markets, FERC could expand its authority at the expense of states and localities," he said.

"Honestly, I'm not particularly troubled by any sort of jurisdictional creep because that power would make its way onto our grid in a way that we could regulate it only after it had been aggregated and put forth to a market that we regulate — a wholesale electric market," McIntyre responded. "And there certainly is no attempt on the part of this commission to in any way thwart the ability of the state, for example, to determine in a retail-level transaction what the owner of the generating resources — what level that owner would be compensated. Honestly, I don't see that as being a particularly grave concern."

Continued on page 43

Ready to Act on DERs, FERC Tells Congress

Continued from page 42

The commission will likely be inviting post-technical conference comments after transcripts of the technical conference are posted.

The three-hour hearing was the first with the full commission since 2015, according to Energy and Commerce Committee Chairman Greg Walden (R-Ore.). Also discussed were the commission's grid resilience inquiry, the financial struggles of coal and nuclear generation, the Public Utility Regulatory Policies Act and the commission's review of its 1999 policy statement on gas pipeline licensing. (See related stories, *FERC Whipsawed Over Pipeline Policy in House Hearing* and *FERC Outlines Gas Pipeline Rule Review*.)

Coal and Nuke Woes

The commission's decision to open an inquiry on grid resilience after rejecting Energy Secretary Rick Perry's call for price supports for coal and nuclear plants came up repeatedly in questions from committee members.

Rep. Joe Barton (R-Texas) called for "regulatory relief" for struggling coal and nuclear generators, saying market changes could result in unsustainable subsidies. "The regulatory burden obviously on nuclear is very high and you can argue that it's also very high on coal plants. If we look for solutions to keep our distressed nuclear plants and coal plants in service, we should first look at regulatory relief and only then look at market relief," he said. He did not elaborate on what regulations should be reduced.

Rep. David McKinley (R-W.Va.) brought up the "domino effect" he said will result if the 1,300-MW Pleasants County coal-fired plant is forced to retire after FERC rejected FirstEnergy's proposal to move it from its merchant unit to a regulated utility. FirstEnergy announced in February it would close the plant in early 2019 if no buyer is found. (See *FirstEnergy Shutting down Unsold Coal Plant*.)

"This is a small county. Thirty percent of the tax revenue comes from that power plant. … That's going to affect their school system. What about their [emergency medical service]? What about their hospital? If this power plant closes down, there's a very high likelihood that the coal producer that supplies that power plant [Murray Energy] will similarly declare bankruptcy. If [CEO Robert Murray] declares bankruptcy, his relief will be to get away from his [United Mine Workers of America] pension responsibility, which currently funds 120,000 retirees. If that's reduced, they would be shifted over likely to the federal Pension [Benefit] Guarantee Fund. I've got a letter from the Pension Guarantee Fund that says, 'Don't put those 120,000 on us because then we'll go under.' So, you see the domino effect of this," he said.

McKinley asked the commission whether it had calculated the cost to consumers of subsidizing the plant.

"I do not have that figure," responded McIntyre.

"We have reason to believe it's less than $50 a year per customer. The consumer currently is paying $50 a year for tree trimming," McKinley said. "I think we have a moral responsibility to look at this thing holistically, rather than just an ideological fight [over] what we think … is a free market."

"Would you agree? Do we have a free market system in energy?" he continued.

"We do not have a perfect market system in energy, that is certain," McIntyre responded.

Rep. Adam Kinzinger (R-Ill.), whose district is home to four nuclear plants, said he was concerned that the loss of nuclear generation would harm resilience. McIntyre said the commission's resilience docket (RM18-1) could result in additional revenue for nuclear plants if FERC determines they provide resilience attributes for which they are not compensated.

Commissioner Robert Powelson reminded Kinzinger of the history of Illinois' move to retail choice. "Those nuclear plants you referenced, customers paid a competitive transition charge as part of a stranded cost investment. So here we are today in your state and my state [Pennsylvania] … where something that was quote 'too cheap to meter' is coming back into the market. … We're being asked theoretically — your constituents are being asked — to do another stranded cost for those assets. So, if I'm a gas operator or I'm an emerging technology in the market, I'm not getting any type of backstop for my resource."

Rep. Bill Johnson (R-Ohio) asked Powelson about his response to Murray's criticism that "FERC didn't do its job" when it rejected the Perry's request. Responding on Twitter, Powelson initially challenged Murray to a debate, a tweet he later deleted.

"I take offense to the word 'feckless' being used to [describe] colleagues that I serve with here," responded Powelson. "My colleagues and the 1,320 [FERC] employees who show up to work every day to do their job around safety and economic regulation and making sure our wholesale power markets are functioning. … I refrained from [pursuing a debate]. I thought it was inappropriate and I dialed it back rather quickly."

Transmission Spending

Several members questioned whether FERC and RTOs were allowing unnecessary transmission spending.

Rep. Frank Pallone (D-N.J.) questioned whether Jersey Central Power & Light's proposed $111 million Monmouth County Reliability Project is necessary to accom-

Continued on page 44

Left to right: Kevin McIntyre, Cheryl LaFleur, Neil Chatterjee and Robert Powelson. | © *RTO Insider*

Ready to Act on DERs, FERC Tells Congress

Continued from page 43

plish the company's reliability goals. "Recently this view was echoed by New Jersey Administrative Law Judge Gail Cookson, who ruled that JCP&L failed to demonstrate that their transmission line is necessary and noted that JCP&L has not seriously considered alternative corridors and ignored non-transmission solutions entirely," Pallone said, adding that the utility should have considered distributed generation, storage and new grid technologies.

"Her decision supports my long-held suspicion that often projects like this … are more about the rate of return for shareholders than reliability for consumers."

Powelson expressed sympathy. "I have a concern when industrial customers come in to the commission as energy users telling us that they're seeing a 400% increase in transmission costs as wholesale [energy] prices are dropping. That's alarming. That tells me that the RTOs at the wholesale level of transmission planning are not doing a very good job of cost containment. And we are all paying for that as consumers."

Rep. Billy Long (R-Mo.) cited complaints by the City Utilities of Springfield that it has seen a substantial increase in its transmission costs in SPP, "most … related to funding transmission projects outside of" the state.

"Some of the projects allow utilities to access renewable energy located outside of the state. However, the benefits [are] far outweighed by the rise in transmission costs," Long said. "SPP's own studies have shown the City Utilities' transmission costs and energy prices are substantially higher than other customers in the Southwest Power Pool. What will FERC do to address the issue of rising transmission costs in" the RTO?

McIntyre said he was unfamiliar with the study Long referenced but agreed to investigate the matter. "Generally speaking, it would be surprising that a particular entity paying those transmission costs is paying significantly higher than other entities served by the same" RTO.

Order 1000

Glick and McIntyre, the newest members of the commission, said they want to take another look at some of FERC's transmission policies.

McIntyre said the commission's transmission planning rules are "something that's ripe for evaluation as to whether it's working as well … as was hoped for when we issued" Order 1000.

Glick said the commission should reconsider how it awards return-on-equity incentives to transmission developers.

"Are we incenting the right thing? For instance, we incent RTO participation, but a lot of … utilities are participating in RTOs regardless of whether they have an incentive or not," Glick said. "We really should be incenting, 'Are we using transmission capacity more efficiently? Are we using new technologies to make transmission capacity more efficient?' Those are the kinds of things that I think congress gave us the authority to do."

Powelson (left) and Richard Glick | © RTO Insider

The House Energy and Commerce Committee's Subcommittee on Energy | © RTO Insider

PURPA

Rep. Tim Walberg (R-Mich.) pressed the commission to revise its enforcement of PURPA, noting it has been nearly two years since the commission's technical conference on the subject. (See FERC Conference Debates PURPA Costs, Purchase Obligations.)

McIntyre said an overhaul of the law would be up to Congress but said FERC can act to prevent abuses of its 1-mile rule and 20-MW threshold. "I think the record is already there to act on the 1-mile rule," agreed Commissioner Neil Chatterjee. He added it "could be a challenge" to get a bill through Congress.

'By Operation of Law'

Rep. Joseph Kennedy (D-Mass.) used his time to urge support for a bill he is sponsoring to address the commission's 2-2 deadlock in September 2014 over whether it should reject the results of ISO-NE's eighth Forward Capacity Auction because of unchecked market power. The 2017-18 auction results became "effective by operation of law" (ER14-1409). Under the FPA, rates take effect 60 days after they are filed with FERC, absent a commission order to the contrary.

Sen. Ed Markey (D-Mass.) is sponsoring similar legislation. (See FERC: FPA Change may not Solve Catch-22 on Vote Deadlocks.)

McIntyre said such occurrences arise "very, very rarely, once every dozen years."

Kennedy interrupted him: "When it does it comes with a fairly big consequence."