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

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# AEP to Spend $4.5B on Largest Wind Farm in US

*By Peter Key and Tom Kleckner*

American Electric Power, once the biggest coal-burning utility in the U.S., now plans the nation's largest wind farm, a 2,000-MW project in the western Oklahoma Panhandle that would be connected to subsidiaries in Arkansas, Louisiana, Oklahoma and Texas by a 350-mile EHV transmission line.

AEP's total investment in the project would be $4.5 billion — $2.9 billion for the wind farm and $1.6 billion for the Wind Catcher Energy Connection line. Its Southwestern Electric Power Co. and Public Service Company of Oklahoma subsidiaries would own 70% and 30% of the project, respectively.

The wind farm, made up of 800 2.5-MW General Electric turbines, will be built for AEP by Invenergy. In addition to being the largest in the U.S., it will be the second largest in the world, behind only the 6,000-MW Gansu wind farm in China.

PSO and SWEPCO seek approvals from regulators in the four states the project will serve, as well as from FERC, by April, AEP CEO Nick Akins said in the company's second-quarter earnings conference call Thursday. The company will re-evaluate the project at that time.

"We are going to have to sit down at the end of that April time period and figure out, 'OK, what are the risks to our shareholders moving forward with this particular project, given not only the regulatory outcomes but also the other risk components that are involved with this,'" Akins said.

One of those other risk components is the project's completion date. It has to be up and running by 2020 to qualify for the federal production tax credit, which ends at the end of 2019. Akins said AEP will recover $2.5 billion through the credit.

SPP confirmed that the project is in its generator interconnection queue for study of its impact on the system.

### SPP Wind Growth

The RTO has seen considerable wind-energy development in the Oklahoma and Texas panhandles, which has caused congestion in the area. SPP will be conducting a high-priority congestion study to address the situation. (See "Committee Gives Congestion Study New Life," *SPP Strategic Planning Committee Briefs: July 13, 2017*.)

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# RTOs to Congress: Don't Lose Faith in Markets

*By Rich Heidorn Jr.*

WASHINGTON — RTO officials acknowledged Wednesday that they are challenged by low power prices and a shifting generation mix but insisted they are up to the task, asking Congress not to abandon its support of wholesale markets.

"Although debate on various market rules is perfectly appropriate, we caution against the potential to add greater uncertainty to the markets by signaling some kind of wholesale retreat from the competitive market model that has been in place since the mid-1990s and has worked well to keep prices low and investment certain," Craig Glazer, PJM's vice president of federal government policy, told the House Energy and Commerce Committee's Subcommittee on Energy.

"The markets are working *very* well," agreed SPP CEO Nick Brown, who said his RTO provides net benefits of more than $1.7 billion annually — a benefit-cost ratio of 11:1, he said. MISO provided $3 billion in benefits last year and $18 billion over the last decade, said Chief Operations Officer Richard

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PJM's Craig Glazer | © *RTO Insider*





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# IN THIS WEEK'S ISSUE

## FERC NEWS


# Ex-FERC Commissioner Tony Clark Offers Solutions for Markets' 'Identity Crisis'

*By Rich Heidorn Jr.*

Tony Clark's term as FERC commissioner ended nine months ago, but he hasn't stopped thinking about the issues that animated him during his four-year tenure.

Clark, a non-attorney who joined law firm Wilkinson Barker Knauer as senior adviser in January, had his coming out in a 16-page white paper titled "Regulation and Markets: Ideas for Solving the Identity Crisis." It was released at the National Association of Regulatory Utility Commissioners' summer meeting in San Diego, a fitting venue for Clark, a former North Dakota regulator who served as NARUC president before his FERC appointment.

Clark's paper mostly addresses the eastern organized markets being buffeted by state policy initiatives, but he also discusses new technologies and trends. He offers his familiar wit, for example, linking the 1978 Public Utility Regulatory Policies Act (PURPA), which Clark has long criticized, to the era of bell bottoms and disco.

Nothing in his recommendations are particularly divisive, surprising or novel. His recommendations on performance-based ratemaking and changes to distribution rate structures, for example, are sensible but no surprise to anyone following New York's Reforming the Energy Vision (REV).

Perhaps his most interesting observation is that moves by New York, Illinois and New England states to subsidize nuclear plants or require utilities to sign out-of-market contracts for renewables have exposed "how thin the veneer of pro-market fidelity" is. It's an issue he first considered in the 1990s when he — then a state legislator — weighed whether North Dakota should abandon its traditional regulated utility model for retail choice.

Although his "philosophical conservative" side favored competitive choice, his "operational and practical conservative" side won out. "Like nearly all other states with much below-average-cost electricity, the value proposition for [competition in] North Dakota did not pencil out," he decided.

Clark concludes that recent moves to increase state control over wholesale generation market "is consistent with the


Clark

factors that have driven public policies in electricity for the last two decades, not a departure from it."

"For many, a 'freer market' was never the end goal," he said. "The market was a tool. Affordable power was the goal. The current markets are still procuring affordable power, but many state public policy makers no longer see that as the only goal."

He also expressed doubts that the eastern RTOs will succeed in their efforts to accommodate state choices while maintaining capacity markets as the primary source of resource adequacy. "While I applaud their efforts to look at creative solutions, I am skeptical of whether further dissection of administrative auctions into state-sponsored resources and competitive resources can succeed," he said. "The complexity of these administrative constructs is remarkable as it exists today. Layering even more auctions, set-asides and carve-outs onto to the current construct may ultimately tumble the house of cards."

*RTO Insider* talked to Clark last week about his paper and his new role. This interview has been edited for length and clarity.

**RTO Insider**: OK, so I read through your white paper and I'm curious: Who was the audience for the white paper and what was your goal in writing it?

**Clark**: Yeah. Well, I suppose there's two audiences. One is more general and then one is probably a little bit more specific. The general audience is just for the public policymakers and certain thought leaders within the electric industry. On a more specific level, the way the paper turned out, it tended to be pretty focused on states. What I would hope is, especially thought leaders in the states in regulatory commissions — but also in legislatures and governors' offices — would take a look at it and say, "You know what? There's some things we should be thinking about." So that at least we're purposeful as we're moving through this time of transition in the electricity sphere. The concern is that it's not purposeful and it's sort of an ad hoc collection of moves like I talked about in the paper, which is one piece at a time, where we keep layering on all these different public policies that when you step back and look at, it may not make sense in the whole.

**RTO Insider**: Yes. I liked your reference to the Johnny Cash song ["One Piece at a Time," which tells a story of an assembly line worker who sneaks Cadillac parts out of the factory, later building a car mismatched from models from 1949 through 1973.] That's one of my favorite songs.

**Clark**: Yeah, that's a great song.

**RTO Insider**: Now that you're no longer a commissioner, were there things in this paper that you said that you would not have been able to say before?

**Clark**: That's an interesting question and I hadn't thought of it that way. I don't think so. I mean, it's not dissimilar to some things that I thought and said along the way at first. It's probably the sort of biggest compendium of all these thoughts put together in one spot. I probably would have said similar things. It's just when you're in the commission, you usually don't have the time, sometimes, to sit down and really think about these things a little bit more holistically. Your day-to-day grind of just moving through your cases kind of takes things over. … Now I have a little bit more time to, I guess, sit back and contemplate.

**RTO Insider**: I recall covering [Wilkinson Barker Knauer partner] Raymond Gifford at the [Independent Power Producers of New York] conference in New York back in May. The subject there was the carbon adder, and he had said, "It'll never happen." (See *Carbon Adder to Test FERC's Independence, IPPNY*

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## FERC NEWS


# Ex-FERC Commissioner Tony Clark Offers Solutions for Markets' 'Identity Crisis'

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Panelists Say.) He agreed that "the most elegant solution is you price carbon into the market" but said "FERC is not going to sign off on a carbon imposition." Do you agree with that?

**Clark**: Well, generally yes. I mean, some of it depends a little bit on how you frame the question. If the question is, "If the states, or a collection of states, or the federal government for that matter" — [chuckles] but I don't see that going to happen any time soon — "put on some sort of carbon adder, would FERC recognize it and allow it to be bid into the markets?" I think the answer there is probably "yes." The commission already does that in the case of [the Regional Greenhouse Gas Initiative] and California. Other governmental bodies through their own legitimate authority putting on a carbon adder — would the commission allow that to be bid in the market? I think so, because it would just be like any other governmentally imposed cost: It's allowed to be offered into the market.

Now, do I think FERC on its own motion is going to go out and throw on a carbon adder? I don't think so. I don't think it would be a wise idea beyond that. I mean, one — just take the politics of what the commission is [facing] now and for the foreseeable future. I don't think it's going to happen.

No. 2 … it wouldn't be in the commission's own interest to do it for a number of reasons. You'd get beat up on Capitol Hill like you can't imagine. And it probably is a little bit, I think, legally suspect. … I think it's a stretch under the Federal Power Act. … And then No. 3, which is as big as anything — if you're a commissioner who is interested in seeing the potential benefits of a joint dispatch model [traditionally regulated states that have joined ISOs or RTOs, such as most of MISO] migrate to other areas of the country, the fastest way to stop that development would be for FERC to go in and start imposing carbon taxes.

And if you look at what's starting to come together in the West, we've talked about not just the [Energy Imbalance Market] but potentially more of a joint dispatch market in certain regions. ... If you want western commissioners to flee from that idea and never come back to FERC again, [never] talk about it, just throw on a carbon tax. I think it would be self-defeating itself in terms of development of markets. It would probably halt markets where they are, in their tracks. You might even have some states start seriously thinking about pulling out of markets that they're already in. If you're from the part of the country I'm from — big red states in the middle of the country that are part of an organized market — if FERC starts looking at levying quote-unquote "carbon taxes" on its own, theoretically, you could see a real backlash in state legislatures in terms of what they allow their utilities to do. And remember that … these markets, they're voluntary.

**RTO Insider**: When I was reading through your recommendations, they all seemed very sensible, very much in accord with some of the things that have been discussed in other states. For example, [New York's Reforming the Energy Vision initiative], with their attempt to de-couple usage from revenues and provide ways for performance-based ratemaking and ways for utilities to make money as system platforms. Am I missing anything in your paper? Was there anything that you felt where you were striking new ground, where you were carving out new proposals, or were you more surveying the landscape and saying, "This is a round-up of what I think makes the most sense," based on the current state of play?

**Clark**: Yeah. I think it's probably more the latter, and my hope was to put it in the conversational style, so that it was accessible to a wide variety of policymakers. Some of them maybe don't every day play in the electricity space. As much as anything, it was probably a distillation of trends that are out there and potential ways to frame the issues as you think about it.

A lot of that deals with rate design, making sure that you're getting the distribution side of things right because this grid is changing. If you keep the same old rate structures that you've always had, you're going out come out with a lot of arbitrage opportunities for new entrants and things like that. You want utilities to be able to provide the platform that allows for other players to do what they're going to do, but to do it on a level playing field in a fair manner that allows them to, and gives them incentives to, invest in that network.

**RTO Insider**: You're not going to have a robust distribution side network if you don't come up with a mechanism to allow those investments to be made. Anything I haven't touched on that you think is important in the context of this paper?

**Clark**: The thing that struck me as interesting over the last few years is, I thought, if there's one region of the country where you might actually get a strong consensus for some sort of carbon price, it was going to be New England because you've got, politically, a group of states that probably are seeing the issues [similarly] and they've already joined RGGI and are part of the organized market.

I would have thought there might be a coalition here that says "maybe you need to step back from some of the other public policies and instead really depend on carbon price to drive the market." But it's just never coalesced and I think it shows the difficulty — even where there's relatively fertile ground for policymakers to rally around the very transparent carbon price. Because it really — it's transparent, which is maybe why it's so tough to get done even under favorable circumstances.

**RTO Insider**: Yeah, I think some of the smaller [New England] states are just not as willing to take on more renewables in the way that Connecticut and Massachusetts are. We heard that loud and clear in some of the sessions we've attended from the likes of New Hampshire and Vermont and Maine, that the size of the carbon price, to make a difference, would be kind of a non-starter for them.

**Clark**: Yeah. That's just it. RGGI, as I mention in the paper, has never really been used to strike dispatch or drive resource selection. It's really been just a funding source for energy efficiency programs and things like that. It funds programs at the state level, but it doesn't really drive resource selection in any meaningful way if the prices are just set too low.

**RTO Insider**: Right, right. Well, great. Well, thank you very much for your time this morning. I appreciate it.

**Clark**: Not a problem.

## CAISO NEWS

# Aliso Canyon Resumes Injections

By Jason Fordney

Southern California Gas Co.'s Aliso Canyon gas storage facility resumed injections Monday, despite Los Angeles County officials' request that a state appeals court prevent the reopening.

"SoCalGas must begin injections to comply with the [state's] directive to maintain sufficient natural gas inventories at Aliso Canyon to support the reliability of the region's natural gas and electricity systems," the company said in a statement sent to Porter Ranch residents, according to the *Los Angeles Times*.

Following a series of back-and-forth court rulings over the weekend, the county filed a petition with the 2nd District Court of Appeal for a stay preventing gas withdrawals until more analysis is done. A judge on Saturday ruled that operations can resume.

The volley of court actions occurred after the California Division of Oil, Gas and Geothermal Resources (DOGGR) issued an order July 19 allowing SoCalGas to resume injections into the facility. The county does not object to withdrawals on an emergency basis, which is currently allowed.

The county wants the court to forestall any withdrawals until it can determine whether DOGGR complied with the law in clearing the facility to resume operations. SoCalGas refused the county's request.

"Before the prohibition on injections can be lifted, SoCalGas must show — and DOGGR must determine — that all necessary steps to ensure the safety of the facility have been completed," the county said in its original filing in Los Angeles County Superior Court last week. Conditions have not been met regarding a risk-of-failure review and emergency response plan, the county contended.

Withdrawals were halted at the facility following the massive methane release there, detected in October 2015 and finally plugged in February 2016. DOGGR and other state agencies recently issued findings that it is safe to resume withdrawals. (See *California Officials: Aliso Canyon Safe to Open*.)

The court filing says county officials met with DOGGR and SoCalGas on July 20, when the company refused to refrain from withdrawals and to disclose when they would resume. SoCalGas did not immediately return a request for comment.

Residents near Aliso Canyon still report health problems they say are related to the leak, including headaches, nosebleeds and nausea. A few dozen residents recently protested resuming gas withdrawals in roadside gatherings reported on local news stations.

California Energy Commission Chairman Robert Weisenmiller and Gov. Jerry Brown have asked for the state to explore permanent closure, and the California Public Utilities Commission has a proceeding underway that is analyzing whether the facility is needed for system reliability. (See *Study to Weigh Aliso Canyon Shutdown*.)

On July 19, SoCalGas issued a statement that it has completed the state's required safety reviews and has implemented a host of safety measures and procedures. The company argues that loss of the facility will create reliability problems in times of severe weather and peak electricity usage.

The county also argues that there is a risk of gas leaks caused by seismic activity in the area, which is prone to earthquakes. "DOGGR and SoCalGas have acknowledged the well-known and very serious risk of a catastrophic earthquake shearing multiple wells at Aliso Canyon," county officials said.

Although the appeals court did not issue a stay, Deputy County Counsel Scott Kuhn told the *Times* on Monday that the courts have yet to rule on the county's request that the state complete their analyses before continuing injections. "We hope that some court will get to the merits and when they do get to merits, they will see that further study of the seismic risk and the environmental risk is necessary before [the utility] can proceed with business as usual," Kuhn said.

# CAISO Board Approves Aliso Canyon Rules Package

By Jason Fordney

CAISO Board of Governors | © *RTO Insider*

FOLSOM, Calif. — The CAISO Board of Governors last week greenlit new rules that allow the grid operator to constrain the operations of gas plants across the state and the Western Energy Imbalance Market (EIM), part of a package of initiatives drawn up in response to the loss of the Aliso Canyon storage facility.

The board unanimously approved the new market rules in a 5-0 vote, as the broader public discussion over Aliso Canyon intensified. (See related story above.)

CAISO Director of Market and Infrastructure Policy Greg Cook explained to the board that there are still operational risks around the loss of Aliso Canyon. The gas constraint tool is limited to use for physical constraints on the grid, not to manage economic conditions.

"There is potential for similar types of physical gas constraints elsewhere outside of

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## CAISO NEWS

# New CAISO Rules Spell Increased DER Role

*By Jason Fordney*

FOLSOM, Calif. — The CAISO Board of Governors last week approved a set of market rules designed to aid the integration of distributed energy resources and transmission-connected energy storage into the ISO's markets.

ISO staff closely consulted with market participants over the past year to develop the Energy Storage and Distributed Energy Resources (ESDER) Phase 2 proposal in response to the growing volume of distributed resources in California. The board's approval of the measure sends the rules to FERC for a new round of comments and review.

DER developers such as energy storage companies are aggressively moving into an area that is seen as increasingly important and profitable — balancing renewables and addressing California's "duck curve," which graphically describes the impact of the variable output of solar generation on the ISO grid at different times of the day. (See *Report: Calif. 'Duck Curve' Growing Faster than Expected*.)

CAISO CEO Steve Berberich told the board that ESDER Phase 2 is part of a broader strategy to accommodate emerging technologies, including demand response, storage and other new types of systems that might be coming to the grid.

"We think that leveraging them is going to be critical to how we manage the grid, and help decarbonize the grid as well," Berberich said. He added that "we are committed to continue to work with all those that provide these services," and with the California Public Utilities Commission.

Storage makes up 20% of the resources in CAISO's interconnection queue, which contains 325 projects totaling 58,000 MW, according to the grid operator. Renewables represent 68% of the generation waiting to interconnect, while conventional resources account for 9%.

### Beyond 10-in-10

As part of ESDER, the board approved a set of alternative energy usage baselines to assess the performance of proxy demand resources, which are DER aggregations of retail customers. It also approved new rules that distinguish between charging energy and station power for storage resources, and a net benefits test for DR resources that participate in the Energy Imbalance Market (EIM).

The ISO currently relies on a "10-in-10" baseline methodology that works well for many large commercial and industrial customers but not for all customer types, CAISO said in briefing documents. Using the 10-in-10 methodology, the ISO calculates a baseline by examining the 45 days prior to a trade date and finding 10 "like" days in which no DR was required. It then uses hourly average meter data to create a baseline representing a typical load profile,

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# CAISO Board Approves Aliso Canyon Rules Package

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Southern California, and our operators have found that this is a valuable tool" to maintain electric and gas system reliability, Cook said.

CAISO asked the board to approve extending some temporary provisions and make others permanent as it develops a new long-term suite of market rules in its Commitment Cost and Default Energy Bid Enhancements (CCDEBE) proceeding, expected to be implemented in fall 2018.

The EIM Governing Body previously approved elements of the Aliso Canyon Gas-Electric Coordination Phase 3 proposal. (See *EIM Leaders Endorse CAISO Gas Constraint Measure*.) CAISO will submit the rules to FERC for approval.

The board's approval extended a temporary rule that the day-ahead market gas price index use information published every morning to better reflect gas costs, and requires a scalar to be included for the next-day gas index to account for tight gas conditions in Southern California and higher gas costs.

Cook said he hasn't seen much need for gas constraints in Southern California in the past year, but the ability to use the scalar would be there if unforeseen events happen.

Also approved was a right for gas generators to file for after-the-fact cost recovery of energy costs if units are mitigated down to their default energy bid.

Stakeholders generally support the gas constraint tool but do not want it to replace or affect the package of bidding rule changes being developed in the CCDEBE proceeding. Representatives from NRG Energy and Pacific Gas and Electric said there are concerns about the package but were generally supportive. But many stakeholders have commented that there are broader problems that must be adequately addressed in the CCDEBE proceeding. The Western Power Trading Forum did not support use of the gas constraint tool unless the scalar is retained.

CAISO's Department of Market Monitoring had expressed concerns about the Phase 3 proposal, but its concerns have been addressed, including an eventual automation of the process whereby constrained transmission paths are deemed uncompetitive and constraints are implemented.

NRG Director of Regulatory Affairs Brian Theaker told the board that his company originally opposed the Aliso Canyon mitigation procedures because it distracts attention from CCDEBE and "long-standing problems with regards to the ISO bidding structure." Suppliers cannot reflect gas procurement costs in bids and could not recover those costs, he said.

The company's opposition has been "tempered a little bit" because of process on CCDEBE, he said. "CCDEBE is a long way off," and the company supports extending the Aliso Canyon measures.

## CAISO NEWS

# New CAISO Rules Spell Increased DER Role

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and the resource is paid for reducing usage below the baseline.

Under the new proposal, baselines for residential resources would be based on a four-day weather match that estimates what electricity use would have been in the absence of DR dispatch under similar weather and on similar days, using a control group of similar users.

Commercial baselines would be based on the 10-in-10 method with a 20% adjustment cap, an average of the previous five days and a control group. Baselines are adjusted using actual load data in the hours preceding a DR event to better reflect variables that might not appear in the historical data.

The package approved by the board also includes a new definition for station power, to distinguish between power used to charge a storage device and energy for station power. It simplifies the definition of station power to align with local regulatory authorities.

The newly approved initiative also incorporates additional gas pricing indices into the "net benefits test" that determines a price threshold to indicate when DR provides a net benefit to all purchasers by reducing the wholesale price. The price threshold is used to determine if an adjustment is required to the settlement of the load-serving entity that procured the load curtailed by the DR resource.

Greg Cook, CAISO director of infrastructure and policy, told the board that the measure allows the ISO to "take into account that the real-time market now has a much broader footprint than just the ISO balancing area, and we should take that into account in the calculation of the net benefits test."

### 'All Hands on Deck'

CAISO stakeholders are supportive of the new baselines and the station power proposals. Tesla and other storage companies urged CAISO to move quickly to develop a new DER product that would pay for storage to take excess generation, but the ISO said that measure needs more development, and it was not included in ESDER Phase 2. (See *Storage Advocates Urge CAISO on DR Product*.)

Ted Ko, director of policy for energy storage company Stem, told the board that the ESDER package and DER will be an important tool in reducing the duck curve and curtailments of excess renewables.

"It seems like a time for all hands on deck," Ko said. "We should be looking for all solutions to reduce that curtailment and bring all solutions to bear." This also includes developing the EIM and regionalization of CAISO, he said.

Stem has been participating in CAISO as a proxy demand resource and has contracts to deploy more than 400 MWh of DER over the next several years in California. The company needs the ISO to provide a market signal to know when charging is most helpful to the grid, Ko said, and technical and policy guidance from the ISO and other companies. He said that Stem and other companies want the ISO to "take this leadership position with urgency" on developing a load consumption proposal.

Berberich said that CAISO will brief the board at its next meeting on the integration of the load-consumption DER product. There are jurisdictional issues to be worked out with the PUC, he said, and he asked storage companies to contribute their ideas.

## ERCOT NEWS

# Texas Commission Rejects SPS ROFR Request

By Tom Kleckner

AUSTIN, Texas — The Public Utility Commission of Texas agreed Friday that Southwestern Public Service does not have the exclusive right to build transmission facilities in its service territory, signaling a final order will be considered at its next meeting.

The PUC's decision was not the answer SPS was looking for when it filed a request asking the commission to determine whether Texas law includes a right of first refusal that overrides FERC Order 1000. (See *Texas PUC Agrees to Take up SPP, SPS Request on ROFR*.)

Wes Reeves, spokesman for SPS parent Xcel Energy, said the company "is disappointed with this ruling and will seek rehearing and appeal." The PUC's next meeting is scheduled Aug. 17 (Docket No. 46901).

SPS contends that the state's Public Utility Regulatory Act (PURA) allows it, as the incumbent utility operating outside ERCOT, the ROFR to build in the service area prescribed by the PUC. That would prevent a potential competitive project under Order 1000.

The commission disagreed, sticking to its staff position that "an incumbent utility's expertise in providing service within its certificated service area does not confer an exclusive legal right to construct transmission facilities within the utility's certificated service area."

Commissioner Ken Anderson offered little of his own reasoning but noted ERCOT's Competitive Renewable Energy Zone (CREZ) project backed his position.

"The fact is, whether it's CREZ lines or non-CREZ lines, we have transmission lines owned by different service providers inside and outside ERCOT that crisscross each other's distribution service territory," he said.

SPS filed a lawsuit in state district court in January, seeking approval to build the project and an injunction prohibiting SPP from issuing a notification-to-construct. The two parties agreed to suspend the proceeding to give the PUC an opportunity to decide how to interpret PURA.

## Parties to See LP&L Contested Case After Aug. Meeting

All parties involved in Lubbock Power & Light's planned migration of its load from SPP to ERCOT agreed they are ready to move on to a contested case, but not until after the PUC's Aug. 17 meeting (Project No. 45633).

Commissioner Brandy Marty Marquez said the delay would give her and PUC staff more time to study data compiled by ERCOT and SPP in a joint study on the potential move's financial and reliability impacts.

"Everybody's ready to go but me," said Marquez, requesting a hearing schedule be set at the commission's next open meeting.

Anderson agreed, saying he hasn't yet "completely digested" the studies.

"There's a lot of good data in the SPP and ERCOT report," he said. "It's not brought together in [a] bottom line, but you can derive it with little work."

The study indicated SPP would see small production cost decreases in all of its transmission zones except for SPS, which serves LP&L's 430 MW of load in a contract that has been extended into 2021. ERCOT would see production cost increases but hopes to balance that out by unlocking wind energy in the Texas Panhandle. (See *Load Migrations Put SPP's Focus on Retention* and *Lubbock Load Could Boost ERCOT Production Costs by $66M*.)

LP&L has said it intends to complete a study similar in scope and scale to the grid operators'. It wants to begin the contested case in May 2018, allowing it to successfully integrate with ERCOT before its "bridge agreement" with SPS expires.

## ERCOT News

# Technical Advisory Committee Briefs

### TAC Allows 2nd Look at CRR Deration

AUSTIN, Texas — ERCOT stakeholders last week tabled a proposal to eliminate the reduction of congestion revenue rights (CRR) payments — "deration," in the ERCOT vernacular — after the measure failed to pass the Technical Advisory Committee.

The nodal protocol revision request (NPRR821) would reverse the deration-settlement mechanism, which was introduced to deter market manipulation but has resulted in large financial losses to generators.

Lower Colorado River Authority's Randa Stephenson recalled when her company lost $2 million over three months because of a forced outage at one of its power plants. She said generators face downside risk because CRRs are settled in the day-ahead market, which sometimes doesn't align with real-time outcomes.

"All the generators are trying to do here is the right thing," said Stephenson, a former TAC chair. "We're trying to hedge our congestion risk in the real-time, and we don't feel like we can do that right now."

The deration price for a CRR path is determined at the constraint level and applied to the CRR payout. CRR payments can be derated if transmission elements are oversold, the target payment is a positive value, or the CRR source or sink is a resource node.

Stakeholders willing to eliminate CRR deration have expressed concern that NPRR821 unfairly changes allocations so that load will bear 100% of the risk associated with deration. Other participants countered that the shortfall is borne by CRR holders when a balancing account is exhausted and said the shortfall risk is not exclusive to load.


Frazier

"We think the deration process that's in place now is appropriate," said Amanda Frazier of Luminant, the only generator to vote against eliminating CRR deration. "It's a risk that can be managed. It allows for appropriate values of CRR on paths where we have unexpected outages that cause those paths to be oversold."

TAC's consumer and independent retail electric provider (REP) segments voted unanimously with Luminant against the measure, providing 10 of the 12 "no" votes. The 15 favorable votes were not enough to meet the required two-thirds threshold to approve the measure.


Comstock

"The real issue is the risk itself is not changing … and you're transferring the risk to load, instead of the market participants that are participating in the CRR auction," said one REP representative, Read Comstock of Source Power & Gas. "I have sympathy for LCRA's issue, but I'm assuming the price they offered considered that risk that existed. This same risk is going to be transferred to load with this NPRR change."

"This NPRR is just like insurance. You overpay for insurance, and I think we're going to wind up overpaying for the CRRs," said Morgan Stanley's Clayton Greer, who voted to eliminate deration. "Right now, we have hedges that don't work when you need them. It's like buying flood insurance that has an exemption for when it rains. Whenever the outages are taken, that's when the congestion hits — and that's when we actually need the coverage."

Asked by stakeholders to weigh in, Beth Garza, the Independent Market Monitor, said she would leave the "very hard discussion" on money and value assessments to the TAC to decide.

"One of the aspects brought up in discussion that hasn't been brought up today in the deration process is a way to manage potential manipulation," Garza said. "I would argue it's a very heavy-handed way to do that, and an unnecessary way to monitor for manipulative intervention in the CRR market. We don't see a need for the current deration process."

"This is very unique when it happens. It's just the generators that get the derates and take the hit," Stephenson said. "We're trying to have a tool here that makes sense for us when we have these unique situations. It's very hard to predict behavior if we're going to have price blowouts on the upside, or CRRs get more expensive and give the load more money."

Comstock urged stakeholders to remain engaged in the auction process. If not, he said, "we're going to see CRR market participants push for more capacity to be sold at longer terms, because they're not concerned about risk that exists if they are oversold."

Stephenson, who was sitting in for John Dumas, the LCRA's normal TAC representative, said she would bring back additional comments and math samples of the "unique situations" to provide a "deeper discussion" on the proposed change.

The motion to table passed by a 23-6 margin. Further discussions will take place at the Wholesale Market Subcommittee (WMS), and possibly the Qualified Scheduling Entity Managers Working Group, before returning to TAC.

"821 is getting rid of the entire deration process in order to fix a relatively small problem," Frazier said. "There are very directed ways to address the LCRA issue. That's an issue we are interested in trying to resolve as well."

### EEA Price Adder Change Tabled

The TAC also tabled for another meeting the only revision request that required significant discussion.

The Texas Industrial Energy Consumers has opposed NPRR768 throughout the stakeholder process. The NPRR would revise the categories of ERCOT-initiated actions, such as energy emergency alerts (EEAs), that trigger a real-time deployment adder so that prices reflect current system conditions.

"What ERCOT is really doing [when it calls DC tie imports] is replicating what a good market outcome would be," said the TIEC's legal counsel, Katie Coleman. "I know EEAs don't happen often, but when they do, this could keep prices at the cap for significantly longer than they would be otherwise, and this is real money for my members."

Referencing ERCOT's systemwide offer cap of $9,000/MWh, Coleman said, "When you have an EEA in ERCOT and prices are at $9,000, everybody has every incentive to sell power into the ERCOT market."

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## ERCOT NEWS

# TAC Briefs

Continued from page 9

In her opening statement, Coleman also said the TIEC is concerned NPRR768 would apply to the Southern Cross Project, a proposed HVDC transmission project that would transport more than 2 GW of electricity from Texas to Southeast markets.

"When you're talking about making a price adjustment for up to 2,000 MW of import, that starts to be real money," she said.

In delaying action on the proposal in the past, stakeholders have noted the Southern Cross proposal was part of a recent docket before the Public Utility Commission of Texas (45624). In a resulting compliance docket (46304), the commission directed ERCOT to determine the project's "appropriate" market participation classification, necessary transmission upgrades and cost allocations, and whether any price adjustments are necessary. (See "Southern Cross HVDC Project," *ERCOT Technical Advisory Committee Briefs*.)

Coleman said that the commission did not direct ERCOT to take specific action on NPRR768 or similar proposals, and that the ISO's decision to file the NPRR, rather than leave the issue to stakeholders, was concerning.

"It's not necessarily an appropriate role for ERCOT to be filing things that increase prices for customers," she said.

Frazier said Luminant, a participant in the Southern Cross litigation before the PUC, asserted a price correction would be needed if ERCOT curtailed DC ties for reliability reasons. As the Southern Cross DC tie would be a merchant tie, she said, there was little reason to be concerned about replicating market actions.

"[Southern Cross] will have those incentives to operate, so this is more of a backup position," Frazer said. "Where if ERCOT is taking command and control over someone's assets that would otherwise be doing something else — and they're doing that to preserve the reliability of the ERCOT system — then there should be a price correction for that action, which is how we treat other reliability actions."

"The problem is, the Southern Cross facility [is] not being built to facilitate market transactions in and out of ERCOT," Coleman countered. "It's being built to facilitate moving wind from SPP and Texas to regulated utilities in the Eastern Interconnection so they can fulfill renewable requirements.

"We're concerned the incentives won't be appropriate for people to sell into ERCOT, even when prices are $9,000."

The WMS will be given the opportunity to weigh in before the discussion is scheduled to resume during August's meeting.

### TAC Approves 5 Revision Requests

The TAC approved two additional NPRRs, revisions to the load profiling guide (LPGRR) and the retail market guide, and a system change request (SCR):

- NPRR822: Establishes the procedure for identifying resource nodes as an "other binding document" instead of a "business practice manual," and adjusts the process for handling a retired resource's nodes by allowing ERCOT to convert CRRs at that node to a different, nearby settlement point.
- NPRR833: Adjusts NPRR827's language to account for the steady state when ERCOT implements the long-term, automated change affecting point-to-point (PTP) obligation bid clearing. The NPRR updates the day-ahead market optimization engine to address situations where a contingency disconnects a resource node. The engine will pick up the PTP megawatts and distribute them to other nodes, instead of ignoring them in a contingency analysis if that PTP sources or sinks at the disconnected point.
- LPGRR063: Clarifies the wording referring to the competitive retailer (CR) of record for certain profile type requests, and specifies only the CR of record may request certain profile assignments.
- RMGRR149: Clarifies certain communications processes for electric service identifiers (ESI IDs) without a REP.
- SCR792: Allows ERCOT to send the consecutive clock-minute average exceedances of Balancing Authority ACE Limit (BAAL) to the appropriate entities, and creates a situational awareness display in the information system's public area that displays consecutive clock-minute average exceedances of BAAL.

*— Tom Kleckner*

# Texas Heat Leads to more ERCOT Demand Records

A Central Texas heat wave is leading to surging demand for electricity, helping ERCOT continue its streak of breaking demand records.

The Texas grid operator's latest record came Friday when it reported 69,525 MW of demand between 4 and 5 p.m., the fifth time in July it exceeded last year's mark of 67,469 MW.

Temperatures in Austin, where ERCOT is headquartered, hit 105 F on Sunday, breaking a 60-year-old record for the date and marking the 13th straight day of triple-digit heat. Nearby San Antonio broke heat records Saturday and Sunday with temperature readings of 105 and 104 F, respectively. The previous records were set in 1950 and 1946, respectively.

On Saturday, ERCOT broke the weekend peak demand record by nearly 1,500 MW when it recorded a preliminary total of 68,413 MW between 4 and 5 p.m. — after hitting 67,728 MW in the previous hour.

And the ISO has set new monthly demand records for nine of the past 12 months, including the last four.

"The system has performed well so far this summer," said ERCOT spokesperson Robbie Searcy. Unable to resist the use of a pun, she said, "We have kept up with monthly record demand in June and July, and blazed past the previous weekend record without any reliability concerns."

ERCOT's final resource adequacy seasonal assessment projected demand to peak this summer at 72.9 GW in August, above the all-time high of 71.1 GW set in August 2016.

Area heat indices have been as high as 109 F, but temperatures are expected to drop into the high 90s for much of this week.

*— Tom Kleckner*

## ISO-NE NEWS

# Hydro-Quebec Dominates Massachusetts Clean Energy Bids

*By Michael Kuser*

Hydro-Quebec and various partners on Thursday submitted six separate proposals to meet Massachusetts' call for 9.45 TWh a year of renewable generation, with one proposal alone meeting nearly the entire energy requirement.

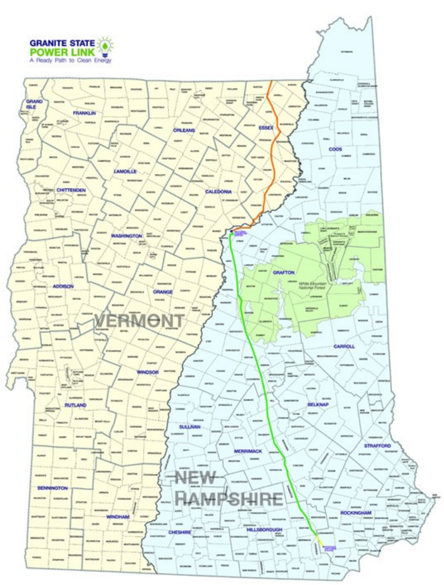
The solicitation is a collaborative effort by the Massachusetts Department of Energy Resources and the state's distribution utilities: Eversource Energy, National Grid and Unitil. Projects will be selected next January, with contracts to be submitted in late April.

Hydro-Quebec partnered separately with Eversource, Avangrid and TDI New England on three different transmission projects, and has agreements with Boralex and Gaz Metro to add wind power into the energy mix on each project at the state's request.

Massachusetts last year enacted a law that requires the state to contract for 1,200 MW of renewable energy, including hydro, onshore wind and solar. A separate clause in the Act to Promote Energy Diversity mandates solicitations for at least 1,600 MW of offshore wind by Dec. 20, with projects to be selected next April and contracts to be submitted at the end of July 2018. (See *Massachusetts Bill Boosts Offshore Wind, Canadian Hydro* and *Offshore Wind Developers Ponder Tx Options*.)

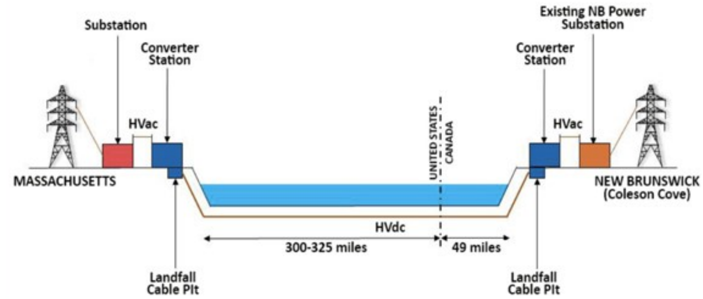
### Deep Competition

Maine-based Emera proposed the Atlantic Link project, a 375-mile submarine HVDC transmission line extending from New Brunswick to Plymouth, Mass., near the retiring Pilgrim nuclear plant and close to the Boston load center. The project would become operational in December 2022 and deliver 5.69 TWh of clean energy per year to Massachusetts at a fixed price for 20 years. Energy prices were not disclosed for any of the projects.



Granite State Power Link route map | *Granite State Power Link*

National Grid partnered with Citizens Energy on two proposed projects. The Granite State Power Link, a 59-mile, 345-kV, HVDC transmission line from northern Vermont to New Hampshire, would deliver 1,200 MW of new wind power from Canada. The companies' Northeast



Atlantic Link landfall schematic | *Emera*

Renewable Link is a 23-mile AC line from Nassau, N.Y., to Hinsdale, Mass., designed to deliver 600 MW of new wind, solar and small hydro into the New England grid.

### Important Opportunity

Eversource has partnered with Hydro-Quebec on Northern Pass, a 192-mile line that would carry 1,090 MW of hydropower to New England — up to 9.4 TWh per year for a period of 20 years starting in December 2020.

"We're confident we can deliver up to 9.4 TWh annually ... we feel ours is a very strong proposal," Eversource spokesman Martin Murray told *RTO Insider*. "It delivers the clean energy that is being sought, and it will be able to do that about two years earlier than any other project that's been proposed."

*Continued on page 12*

# ISO-NE NEWS

## Connecticut Governor Orders Financial Analysis of Millstone Plant

By Michael Kuser

Connecticut Gov. Dannel Malloy last week ordered state regulators to assess the economic viability of the Millstone nuclear power plant and determine whether the state should provide it financial support. Millstone supplies about half of Connecticut's electricity.

The Connecticut General Assembly in June failed to pass a bill that would have allowed the 2,111-MW nuclear plant in Waterford to bid into the state procurement process (S.B. 106). Millstone owner Dominion Energy had sought the legislation to boost the plant's revenues, which have suffered from low-priced natural gas. Gas-fired generators often set LMPs in New England.

Malloy's executive order also directs the state Department of Energy and Environmental Protection and the Public Utilities Regulatory Authority to assess the role of large-scale hydropower, demand-reduction measures, energy storage and emissions-free renewable energy in helping Connecticut meet its ambitious targets to cut its carbon output.

Millstone nuclear plant | *NRC*

The state's Global Warming Solutions Act of 2008 mandates cutting greenhouse gas emissions to 10% below 1990 levels by 2020, and to 80% below 2001 levels by 2050.

### Show us the Books

The governor's July 25 order directed DEEP and PURA to use "the best available information, including such facilities' audited financial statements and such other financial data that is reasonably requested by [regulators]" in their economic analysis of Millstone.

Matt Fossen, spokesman for the Stop the Millstone Payout coalition, said "it is essential that Dominion fully disclose the plant-level financials of Millstone; otherwise the investigation won't be truly comprehensive or accurate."

The coalition — sponsored by competitors Calpine, Dynegy and NRG Energy and the Electric Power Supply Association (EPSA) — had argued S.B. 106 would be a burden on ratepayers and an unnecessary handout to a power plant that had not been proven to be unprofitable.

The group in April released a study by energy consultancy Energyzt that showed the Millstone plant has earned at least $3 billion in profits since Dominion bought it in 2001 and will likely earn an additional $2.2 billion in after-tax income from now through 2030. Dominion spokesman Ken Holt criticized the Energyzt report as "loaded with gross assumptions and preposterous claims, with no real data." (See *Millstone No Dead Weight for Dominion, Says Opponents' Study*.)

### ZEC Suits Dismissed

The legislation would have made Millstone the only eligible nuclear generator in Connecticut's competitive bidding process and awarded it a five-year contract if it bid lower than competing renewable resources. The bill would have set an annual limit on nuclear energy purchases at 8.3 million MWh, equivalent to half of Millstone's output.

The Connecticut measure would have been similar in effect to the zero-emission credit programs that EPSA and its members are contesting in New York and Illinois.

A federal judge in New York dismissed all claims in the suit against the state's ZEC program. (See *NY ZEC Suit Dismissed*.) The ruling came less than two weeks after another federal judge dismissed challenges to Illinois' ZEC program on July 14. (See *Illinois Zero-Emission Credit Suit Dismissed*.)

EPSA and its members in Illinois on July 17 filed an appeal with the 7th U.S. Circuit Court of Appeals. They argued they stood to lose millions because the subsidized nuclear plants would suppress capacity and energy prices. The plaintiffs are expected to also appeal the New York decision to the 2nd Circuit.

## Hydro-Quebec Dominates Massachusetts Clean Energy Bids

*Continued from page 11*

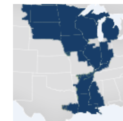
Hydro-Quebec spokeswoman Lynn St. Laurent said, "In terms of our export markets, there is this very important opportunity in Massachusetts, and it's happening now. We're talking about an approximately 1,000-MW transmission line providing a minimum of 8.3 TWh to Massachusetts. It can go higher than that but we're leaving some room. In some cases, we know Massachusetts wants to potentially add some smaller projects into the supply."

Avangrid submitted several proposals Thursday, some wholly owned by the company and others joint partnerships, but it did not release a list. Its subsidiary, Central Maine Power, is partnered with Hydro-Quebec on the New England Clean Energy Connect, a 145-mile, 320-kV HVDC line that would carry 1,200 MW of hydro and wind energy from Canada to Maine.

Avangrid CEO James P. Torgerson told analysts July 19 that his company plans to bid multiple transmission and renewable solutions into the solicitation. "They're looking for incremental hydro on a firm basis but also new Class I renewable portfolio standard, which would be wind and solar. A combination of both could include transmission projects under a FERC tariff," he said.

Hydro-Quebec has also linked up with TDI New England on the New England Clean Power Link, a 154-mile underwater and underground transmission line that would transmit 1,000 MW of Canadian hydropower under Lake Champlain to Vermont.

## MISO NEWS



# MISO Rejects Cost Recovery for Customer-Funded Projects

*By Amanda Durish Cook*

MISO's Steering Committee last week declined to reconsider a stakeholder proposal that would allow funders of transmission upgrades for lines under 345 kV to recover some of their costs through the RTO's allocation process.

Wind developer EDF Renewable Energy and nonprofit Wind on the Wires approached the committee during a July 26 conference call to insist again that costs for customer-funded upgrades be categorized as "non-[MISO Transmission Expansion Plan] upgrades," a project type they said would address "chronic congestion on existing transmission elements that do not meet the criteria for market efficiency projects or multi-value projects."

Under MISO's current rules, only upgrades on lines 345 kV or above qualify as market efficiency projects.

The call marked the second time the issue had come before the Steering Committee, which had previously assigned the issue to MISO's Regional Expansion Criteria and Benefits Working Group (RECBWG) in the spring. EDF representatives argued that the issue wasn't given a fair hearing and was dismissed too quickly, and asked the committee to direct the RECBWG to re-examine the issue.

Xcel Energy's Carolyn Wetterlin, chair of the RECBWG, said the working group generally agreed that "if a market participant chose to fund [an upgrade], they should have done it without an expectation of future reimbursement." Stakeholders participating in the working group voted against taking up the proposal, which some attributed to buyer's remorse after EDF voluntarily decided to upgrade the MISO grid but did not receive the expected benefits.

According to Wetterlin, RECBWG members pointed out that customer-funded upgrades are performed outside the MTEP. As such, they aren't subject to the RTO's transparent standards for determining whether a project is the most efficient solution for solving the transmission issue.

The RECBWG concluded that the issue is still not worth pursuing, Wetterlin said.

### The 'but for' Principle

EDF's Great Western Wind Project in Oklahoma | *EDF*

"We think there's need for a deeper discussion at the RECBWG," Wind on the Wire's Natalie McIntire countered.

EDF argued that its simple cost reimbursement would only apply to new customers that could not have been granted new service by MISO "but for" the customer-funded upgrade.

"We're trying to get some compensation when new users come on the grid," said Bruce Grabow, an attorney representing EDF. "This wouldn't be a full-blown cost recovery ... it's just a reimbursement of a portion of installed costs if the next customer coming down the pike couldn't get network service but for the network upgrade."

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# MISO June Operations Align with Expectations

*By Amanda Durish Cook*

MISO's system operated as intended in June, which saw the usual early summer increase in loads, lower-than-expected natural gas prices and near-normal temperatures.

The RTO on June 13 hit a 111-GW peak for the month, 1 GW under the June 2016 peak, MISO Vice President of System Operations Todd Ramey reported during a July 25 Informational Forum. Average load was about 80 GW, up 10 GW compared with May and an expected outcome of the transition into summer, he said.

The increase in load was offset by the return of about 21 GW of generation from spring maintenance outages.

Prices averaged $29/MWh in the day-ahead market and $28.13/MWh in real time, lower than in May, where average prices for both hovered around $30/MWh. The small reduction resulted from natural gas prices averages staying below $3/MMBtu, a 7% decline from the prior month, Ramey said.

Two events caused real-time prices to deviate sharply above the day-ahead during the month, including a forced transmission outage in Louisiana on June 19 and a June 23 "contingency-related" event affecting the entire system.

While conditions in June were largely in line with norms, the MISO footprint experienced stresses from a mid-July heatwave that likely affected price and load, which will be reflected in the RTO's July operations report, due out later this month.

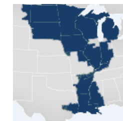
"We just came off a week where parts of the footprint experienced some pretty extreme conditions," CEO John Bear said.

Bear commended MISO control room staff and generation operators for successfully managing the high summer heat. He attributed smooth operations to the training and skill of operators.

Indianapolis Power and Light's Lin Franks asked if MISO is considering turning to a dual-peak model using separate winter and summer dual peaks. The RTO currently models its peak using only summertime conditions.

"We have seen a narrowing of the gap between the summer peak and the winter peak," Ramey said. "We observed that a couple of years ago in the polar vortex" and continue to see it, he said, adding that MISO staff may consider modeling the separate peaks.

## MISO NEWS



# MISO Rules Must Bend for Storage, Stakeholders Say

*By Amanda Durish Cook*

MISO must fully consider the special attributes of energy storage devices before developing new rules that enable those resources to participate in the RTO's wholesale markets, stakeholders said this week.

Stakeholders participating at a July 24 Common Issues workshop asked MISO to recognize the ability of storage to postpone transmission upgrades, classify prospective storage projects under a new study process, and create specific compensation rules and modeling procedures for the technology.

And participants had another piece of advice: Be prepared to change the rules as storage technology advances.

Workshop leader Carolyn Wetterlin of Xcel Energy said the workshop would not directly produce policy decisions but was rather intended to gather ideas on integrating storage into MISO markets. She said the RTO would plan a follow-up meeting for Aug. 24 to decide which stakeholder committees would take up energy storage issues.

Xcel's Carolyn Wetterlin (left) and Justin Stewart, MISO stakeholder relations staff. | © *RTO Insider*

### Storage as a Transmission Solution

Entergy's Ayesha Bari said battery storage should not be treated purely as a generation resource because it can respond more quickly than a generator and does not depend on fuel sources. Batteries are more akin to transmission assets because they do not produce power but provide "time-shifted load consumption on the electric grid," she said. They can also be recommissioned for use at other problem sites after helping to defer a transmission project as long as possible.

Invenergy Director of Regulatory Affairs John Fernandes agreed with the principle of using storage to defer transmission and distribution system upgrades. He offered the example of installing a battery to equip a 100-MW substation to handle a 125-MW peak load, with charge gathered when load is less than 100 MW to in order to handle the extra 25 MW during peak intervals. He also asked for rules that would monetize such use.

"If we can firm up the opportunity and how this looks in MISO, we'll get a lot more proposals," Fernandes said. "I'm not sitting here asking for a handout for energy storage; I'm talking about optimizing the grid."

Fernandes said MISO must specifically address the instances when a storage resource is required to remove itself from market participation in order to recharge. "In some places, they call that not following your set point, and that's frowned upon," he said to laughter from stakeholders.

"I think a product definition and market rules could assist modeling. What are your

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# MISO Rejects Cost Recovery for Customer-Funded Projects

Continued from page 13

New interconnection customers can currently enter the grid and reduce some of the benefit that the original funders of the project had expected, as MISO grants non-firm usage rights to the customers that paid for the upgrades, he said.

Grabow said the poor financial benefits of market participant-funded projects are evident: No such projects were brought forward in MISO's transmission plans from 2014 to 2016.

"This occurred notwithstanding known congestion on voltages below 345 kV. Participants see the need but are not utilizing this avenue because of the lack of reimbursement and/or retained benefit," EDF and Wind on the Wires said in a joint presentation.

### 'Devastating' Rate Shocks

Indianapolis Power and Light's Lin Franks said that "having after-the-fact cost allocation would seriously complicate" MISO's planning processes.

"It could cause rate shocks that could be quite devastating," Franks said, adding that customer-funded upgrades are "just the way the world works," with customers accepting the risks of funding their own upgrades. He noted that transmission rates cover the cost of using existing upgrades on the system.

NRG Energy's Tia Elliott said that the stakeholder process was not necessarily flawed even if EDF and Wind on the Wires did not receive the stakeholder response that they wanted from their proposal. ITC Holdings' Cynthia Crane, who attended the RECBWG meetings, said she thought the issue was "properly vetted" at the RECBWG.

Elliott pointed out that the Steering Committee's decision does not preclude the two companies from approaching the Advisory Committee with its proposal. And the two companies could always file a complaint at the FERC level, according to We Energies' Tony Jankowski.

Participant-funded transmission projects have always been excluded from MISO's cost allocation procedures, while projects not eligible for allocation can be recovered through a zonal transmission rate. The RTO is considering changes to its cost allocation rules — which have not been altered since the integration of MISO South in 2013 — especially given that Entergy's integration transition period, which limits cost sharing in MISO South, expires next year. The RTO has said that it may lower the 345-kV threshold on market efficiency projects. (See *MISO Stakeholders Debate Postage Stamp Cost Allocation*.)

## MISO News

# MISO Rules Must Bend for Storage, Stakeholders Say

Continued from page 14

thoughts on that?" Customized Energy Solutions' David Sapper asked.

"I think there needs to be a good bit more certainty on development rules and processes before robust projects are brought forward," Fernandes replied.

Entergy's Yarrow Etheredge said that MISO's annual Transmission Expansion Plan — rather than the RTO's interconnection queue — is the more appropriate forum for considering the use of storage based on its potential benefits to the system, which could require specific studies.

"You're not looking at the right things in the generator interconnection process," she said.

Jason Burwen, policy director of the Energy Storage Association, joined the chorus, saying storage can also defer transmission upgrades by relieving congestion. Batteries can also provide several uses beyond ancillary services, including "grid balancing, backup, system capacity, network capacity, curtailment avoidance and energy arbitrage." He said MISO's "lack of clear market mechanisms" fails to monetize storage benefits.

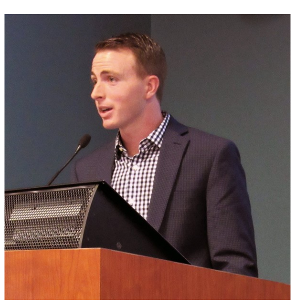
"The main barrier to storage is lack of an effective means to value and compensate it for its capabilities," Burwen said. "If we can modernize the Tariff, operating and planning structures, we expect that they can compete on their own merits."

Fernandes introduced a concept he dubbed "smoothing with storage," in which storage can flatten renewable output spikes by providing firm output over a one-hour time block. Xcel's Beth Chacon added that storage technology can temper rapid solar ramping rates.

Lorenzo Kristov, an adviser on market and infrastructure policy at CAISO, said the future grid may be an "integrated decentralized system" in which the RTO manages several local distribution areas comprised of microgrids, a departure from a central transmission system that delivers energy across hundreds of miles.

Kristov said energy storage market integration requires complementary strategies, which include valuing storage's services and not just the delivered electricity, laying out "storage-as-demand response" rules and creating procedures for either resource owners or RTOs to manage a battery's state of charge and set maximum charge and discharge rates.

"There really aren't well-defined services that these storage resources can be compensated for," Kristov added.



Griffin

DTE Energy's Nicholas Griffin said his company's pumped storage facility in Ludington, Mich., currently offers into the market one day at a time through an energy limited resource offer based on the company's own optimization to determine the amount bid into the market. About 10 hours of pumping at the Ludington station yields about eight hours of generation for the 1,872-MW facility.

Left to right: David Mindham of ITC Holdings, Yarrow Etheredge and Ayesha Bari | © RTO Insider

Griffin said DTE would like MISO to model storage assets as both generation and load sources in market and planning processes and optimize generation and load cycles as far as 10 days in advance.

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## MISO NEWS

# MISO Rules Must Bend for Storage, Stakeholders Say

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The RTO should also learn to "better leverage a flexible source or sink of energy for operational or reliability reasons," Griffin said.

"We want MISO to fully leverage existing assets while enhancing the market to accommodate new ones," he added. "All these resources are different, and we need to figure out to properly and adequately compensate them for services that are needed."

"If you want to talk batteries, well, I guess I have a huge battery at Lake Winnipeg," said Manitoba Hydro's Audrey Penner, noting the company has pumped hydro storage capability between 2 and 10 TWh. Penner said she "strongly disagrees" with limiting a MISO storage definition to either a battery definition or four-hour storage capabilities.

Burwen said that several megawatt-scale storage facilities are nearing a decade of operations across the nation and said that technological advances in storage capability, including flow batteries using electrolyte liquid and flywheel mechanical storage, are driving a surge in new projects.

"You're opening up a very wide range of possibilities," he said. "Utility and transmission owners, customers and third parties are all operating battery storage."

The cost of lithium ion batteries — the nation's dominant storage technology — have decreased from about $1,000/kWh in 2010 to $273/kWh in 2016.

"Costs of battery storage have been declining very rapidly," Burwen said. "Battery storage generally tops out at four hours, but I think that's a matter of cost. You're going to see potentially longer duration assets as those costs go down." By 2020, developers are expected to add about 3,900 MWh of storage on an annual basis in the U.S., Burwen said, citing projections from the ESA.

Ludington pumped storage facility | *Consumers Energy*

### 'No One-Size-Fits-All'

"It could change how we use energy," said MISO Director of Market Research and Development Jessica Harrison, adding that the RTO continues to mull storage definitions.

"We want to work quickly, but we don't want to move too quickly. We don't want to pin ourselves in a corner" by getting storage rules and definitions out too soon, she said.

"There is absolutely no one-size-fits-all solution for this area," MISO External Affairs Policy Advisor Jennifer Richardson said.

MISO took a stab at one solution earlier this year in a FERC compliance filing responding to a complaint by Indianapolis Power and Light over compensation for a 20-MW battery at the utility's Harding Street Station. (See *MISO Ordered to Change Storage Rules Following IPL Complaint*.) The RTO proposed to create a new resource category — Stored Energy Resource–Type II — that would not be limited to providing regulation services (ER17-1376). Instead, it would be required to function largely as a DR resource, except that it would be treated as a regular generation resource for settlements, and would not be eligible for revenue sufficiency guarantee or day-ahead margin assurance payments.

Jennifer Richardson (left) and Jessica Harrison | *© RTO Insider*

Richardson said that while MISO generally agrees with FERC's Notice of Proposed Rulemaking requiring RTOs to remove market barriers for storage and distributed energy resources, it also believes the two types of resources should be considered separately. (See *FERC Rule Would Boost Energy Storage, DER*.)

MISO thinks that "prescriptive measures for DERs aren't as ripe," Richardson said, adding that the RTO must collect more data on how DERs behave in other markets before it creates its own rules.

Fernandes cautioned MISO against taking too much time to craft storage rules, noting that the discussion has already gone on for over a year.

"I guarantee whatever rules are put in place for storage will have to be changed frequently," he said. "If [it takes too much time] to get revenues in place, we're going to go somewhere else."

"We expect this to be a continuing process. We don't expect to have one response and call it a day," Harrison said.

"The worst thing that I think can happen is we do nothing and we receive very specific FERC guidance on a tight timeline," Richardson said.

## MISO News

# UMERC Upper Peninsula Plan Draws Opposition

*By Amanda Durish Cook*

Critics are pushing back on a plan by Upper Michigan Energy Resources Corp. (UMERC) to build two natural gas-fired generators in Michigan's Upper Peninsula, claiming that the company hasn't adequately justified the need for them.

The Michigan Public Service Commission last year approved a settlement to create UMERC, which consists of the electric and gas distribution assets of Wisconsin Electric Power Co. and Wisconsin Public Service, both subsidiaries of Milwaukee-based WEC Energy Group. (See *Michigan Upper Peninsula Getting its Own Utility*.) The company earlier this year filed for a certificate of necessity to build two reciprocating internal combustion engines — at a combined 183 MW — to replace We Energies' 431-MW coal-fired Presque Isle Power Plant (18224).

The PSC is expected to decide on the application in the fall. If approved, construction would begin early next year, with the plants expected to be in service by 2020.

But the company's $277 million plan is now a target of criticism from multiple organizations that charge that the application was not well thought out.

### 'Closed-Door Negotiations'

The Chicago-based Environmental Law and Policy Center (ELPC) contends that the gas-fired projects are the result of "closed-door negotiations" between UMERC and Tilden Mining, owner of a local iron mine and the largest future customer of the proposed plants.

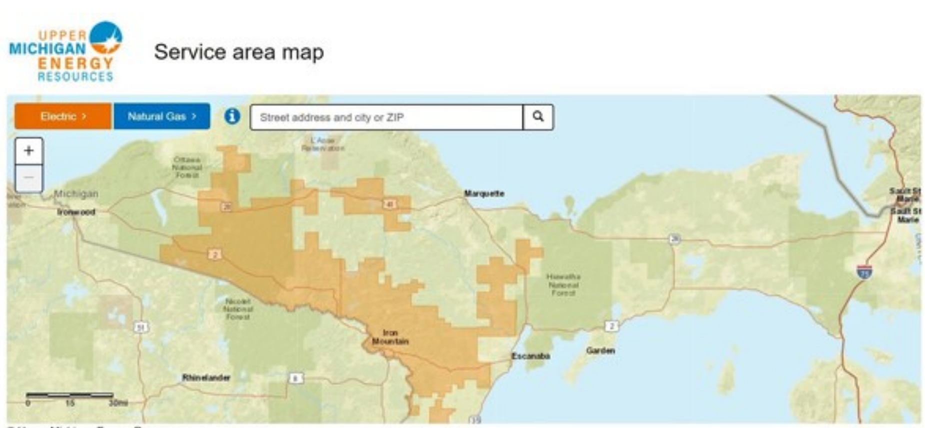
In a mid-July brief asking the Michigan PSC to reject UMERC's application, ELPC argued that the company flouted an official PSC process that requires developers to first study renewable alternatives to fossil fuel-based projects, and instead prematurely agreed to Tilden's request for natural gas generation — and no other technology — in a special contract.

"Prior to signing the contract, no analysis was done by WEC to determine whether [reciprocating internal combustion engine] technology was the most reasonable and prudent means of supplying electricity in what would become the UMERC service territory in Michigan's Upper Peninsula," ELPC said.

"Even though ELPC fully supports the closure of the Presque Isle Power Plant, we're concerned about the process here. In order to pass the cost of the proposed gas units on to its customers, UMERC has to look into several things and one of them is the partial displacement of the proposed generation through renewables," ELPC senior staff attorney Margrethe Kearney told *RTO Insider*.

According to Kearney, UMERC only studied a single-source scenario in which renewables met 100% of the need in the Upper Peninsula.

"I don't think anybody at this point thinks that renewables will cover all of the needs [in the area]," Kearney said. "That's what flagged our concern. We said, 'Wow, they didn't really look into this.'"




© Upper Michigan Energy Resources

When UMERC did factor renewables into its plan, the company neglected to reduce a corresponding amount of capacity from the proposed gas-fired plants, making the renewables appear costly and unnecessary, Kearney said.

"I find it troubling that they wouldn't go back on whatever project they agreed on with the mine and consider replacement of some of the gas units with renewables. They did it out of order," she said.

Kearney also worries that UMERC may be overlooking renewables to the detriment of its customers.

"The amount that they're building is pretty significant," she said. "It's more capacity than what they need. I don't think there's any question that they're not going to need to build anything for a long time. But they're not looking at five years ahead when the cost of storage and renewables drops."

While Kearney said she understands that energy is expensive in the Upper Peninsula, her organization wants to ensure that the region's energy "is crafted with all of the factors in mind."

"I can't say that this is the best option for the rest of the customers. The only stakeholder involved in the process was the mine. The goal is not to accuse them of a nefarious plot, but it really calls into question the legitimacy and credibility of the proposal," she said.

### UMERC's Defense

UMERC stands by its filed proposal.

"We believe our proposal will provide a long-term, low-cost source of electric power to the Upper Peninsula," WEC spokeswoman Amy Jahns said.

UMERC considered multiple renewable supply options for the Upper Peninsula, but they weren't the best fit for the region, according to Jahns.

"Those options were found not to be a low-cost and reliable source of power. Wind and solar energy options are limited to generating or producing intermittent power that would not meet the need of our customers.

*Continued on page 18*

## MISO News

# UMERC Upper Peninsula Plan Draws Opposition

Continued from page 17

In addition, advances in battery storage technology do not meet the need for this project," she said.

The Marquette County Board of Commissioners penned a resolution in support of UMERC's plans, claiming the "environmental benefits of the new generating solutions will greatly reduce regional air emission and will negate the need for the development of costly major transmission lines."

### Overbuilding?

Nearby Cloverland Electric Cooperative also asked the PSC to deny the certificate of necessity, saying that UMERC "insufficiently addressed a number of issues contained in its application."

Cloverland contends that UMERC is overbuilding capacity in relation to need in the area, and that the proposed plants may cause congestion on the local transmission system, forcing the cooperative to pay system reliability, voltage or local reliability payments to MISO. It also asked the PSC to shield it from such payments.

"Since transmission is an alternative to UMERC's proposal and transmission would not create the cost risks for Cloverland that the [proposed] facilities do, Cloverland would have no objection to the commission conditioning the relief in this case on UMERC holding Cloverland harmless from the cost risks UMERC's choices have created," the cooperative said in a brief with the PSC.

In its application for the certificate, UMERC said its integrated resource plan demonstrated that the projects were needed only to replace Presque Isle and would not result in "wasteful duplication of facilities." The company also said that the two plants are the "most reasonable and prudent alternative under the alternate scenarios analyzed," including new transmission or upgraded transmission, new renewable sources and energy efficiency programs.

Cloverland also finds fault with the "extensive analysis" UMERC claimed it performed under its IRP.

"UMERC's integrated resource plan failed to consider a number of potential solutions that could have potentially led to results that would be more beneficial and more efficient to the entire Upper Peninsula. The integrated resource plan provided by UMERC is nowhere near comprehensive enough for this commission to grant the relief requested," Cloverland wrote.

Michigan Technological University also intervened in the case, claiming that as an interruptible gas customer, "the availability and reliability" of its gas supply may become compromised by possible gas capacity constraints introduced by the two new plants.

"The Northern Natural Gas Pipeline is already capacity constrained during peak demand periods. And without adequate safeguards in place, the addition of UMERC's … electric generation facilities will only further constrain the natural gas capacity in the Upper Peninsula," the university said, asking the PSC to condition UMERC's certificate on the "adequate supply of natural gas" for all customers served by the Northern Natural Gas Pipeline.

Jahns said that UMERC has "received no evidence that our project will adversely impact" the university.

## NYISO NEWS

# NY ZEC Suit Dismissed

*By Michael Kuser*

A federal judge last week dismissed all claims in a suit against New York's zero-emissions credit program, the second such victory for state nuclear subsidies after a complaint over the Illinois ZEC program was thrown out July 14.

Judge Valerie Caproni of the U.S. District Court for the Southern District of New York granted motions to dismiss the case from the Public Service Commission, the defendant, and intervenor Exelon, owner of the three New York nuclear plants that would receive ZEC payments (16-CV-8164).

"Although no individual state can reverse the trend all by itself, New York and many other states have decided that they will do their part to reduce the emissions that contribute to global warming," Caproni said. "The issue in this case is whether the method New York has chosen to facilitate its doing so is constitutional. … The court concludes that the New York [ZEC] program is constitutional."

Her 47-page decision rejected every one of the plaintiffs' arguments, including claims that the program intruded on FERC's authority to regulate wholesale prices, and that New York violated the Constitution's dormant Commerce Clause by favoring in-state generators.

The Electric Power Supply Association (EPSA), which filed the New York challenge with several members, said it would appeal the ruling. "We'll continue to fight these nuclear bailouts, which cost ratepayers billions, crowd out investments in true renewables, and distort and could eventually destroy the established wholesale power markets," said David Gaier, spokesman for EPSA member NRG Energy. On July 17, EPSA and its members appealed the dismissal of the Illinois suit to the 7th U.S. Circuit Court of Appeals. (See *Illinois Zero-Emission Credit Suit Dismissed*.)

### Affirmation of CES

Gov. Andrew Cuomo praised the ruling in a statement: "The court forcefully ruled that the Clean Energy Standard (CES) and its zero-emissions credit program are valid tools to use to combat climate change. At a time when the federal government has abdicated its leadership on climate change, New York will continue to do all that we can to ensure that current and future generations have a clean and safe environment in which to live and prosper."

The ZEC program, initiated as part of the CES last August, requires utilities in New York to procure ZECs that are generated by Exelon's three in-state nuclear power plants. The PSC claimed that the program helps avoid the closure of the upstate nuclear plants, which the state needs to meet its goal of reducing carbon emissions and having 50% of energy produced by renewable resources by 2030.

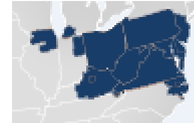
EPSA, and members Dynegy, Eastern Generation and NRG, joined Roseton Generating and Selkirk CoGen Partners in arguing they would lose millions because the subsidized nuclear plants would suppress capacity and energy prices.

Caproni used colorful language to frame her decision, citing President Trump's description of climate change as a "hoax" and paraphrasing a famous line from "Romeo and Juliet": "A rose by any other name still smells as sweet."

On the plaintiffs' argument that the ZEC program is directly tied to NYISO's wholesale markets, Caproni said: "This argument is no more than an attempt to fashion a 'tether' by jamming a square peg into a round hole; plaintiffs' argument rewrites the CES order. The CES order itself does not require the nuclear generators to sell into the NYISO auction."

The Illinois and New York decisions are the latest in a string of federal court cases testing the boundaries between state and federal jurisdiction over electricity markets.

"Under current law, states have broad authority to advance a cleaner electric grid," said Ari Peskoe, senior fellow in electricity law at Harvard Law School, who tracks constitutional challenges to state energy policies. "If courts rule against the states on appeal, their decisions might limit the scope of future state clean energy programs."

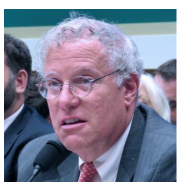


# Containment Policy: PJM Takes Up Cost Caps

*By Rory D. Sweeney*

VALLEY FORGE, Pa. — After months of debate in several transmission planning venues, PJM has begun discussing the role and significance of cost-containment assurances in bids for transmission projects under FERC's Order 1000.

The debate has elicited frustration both from merchant transmission developers, who feel they should receive a competitive edge for sticking to a budget, and representatives of load, who say there is currently little incentive for developers to carefully count pennies in their estimates. A special session of PJM's Planning Committee has held two meetings on the issue, the second of which last week focused on how cost-containment could be factored into the RTO's planning.



Glazer

Craig Glazer, PJM vice president of federal government policy, described a proposed four-stage cost cap review process — which includes examining cap provisions during project submission, evaluation, approval and construction — and outlined potential implementation issues. He preceded the discussion with a round of "Who Does What?" — a fictional gameshow he's used before to highlight a lack of clear jurisdiction on transmission issues. (See *Who Decides? Panel Highlights Blurred Jurisdiction on Tx*.)

The submission process needs to include rationale for any exclusions to the cap in order to avoid "an exclusion so big it effectively makes the cost cap meaningless," but also provides for confidentiality, he said.

"If you start exposing every element of the cost cap [publicly], all you're doing is telegraphing to vendors how much you're willing to pay for that portion of the project," he said.

PJM's "tentative view at this point" is to limit cost caps to construction costs that would include the internal cost of capital to finance the project, which is the "where the competition is" between proposals, he said.

"If somebody wants to submit … a life-of-the-asset project construction cost, we're not going to consider that," he said. "You can present that at FERC as part of your rate filing, but … don't file it here."

Transource Energy's Dan Rogier agreed that any cost cap should focus on construction. "Those aspects of a project that are harder to track over time … should carry less weight than things that are known from a construction standpoint," he said.

Another issue, Glazer said, is identifying who enforces the cap once it's approved. PJM is not a regulatory agency, he said, so if it is put in charge, "we're in this odd position of calling balls and strikes … for load," he said. "I'm effectively the construction manager."

He also made it clear that cost caps are just one component — and not the most important one — of PJM's selection criteria and should be voluntary.

"You can't make someone file a cost cap," he said.

Representatives from several transmission owners, including Transource, ITC Mid-Atlantic Development, Duquesne Light and LS Power, agreed that cost caps should be voluntary.

However, LS Power's Sharon Segner urged PJM to be more proactive.

"We think, from a PJM perspective, that this is a good development," she said. "We think that cost caps should also be encouraged … because risks are being transferred and that has the potential to bring consumer benefits."

The "main role" for PJM, she said, is to select the most cost-efficient, cost-effective project.

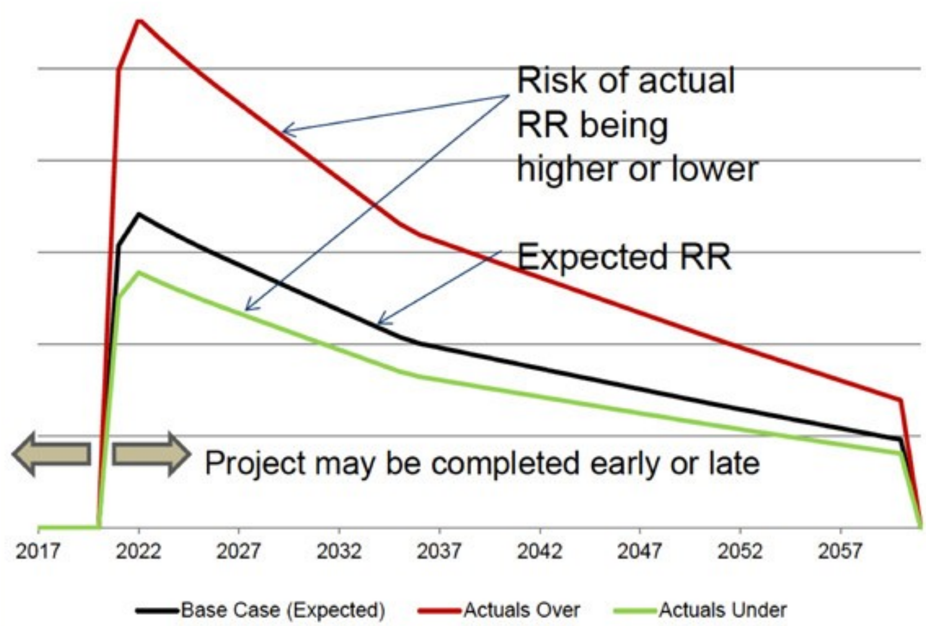
John Farber of the Delaware Public Service Commission said cost caps are not a "panacea," but that the discussion is important for addressing a larger issue.

"There's very little ammunition that customers have [today] to argue as to whether or not costs are reasonable to be recovered," he said. "I think that's a lot of the frustration that's driving this. … Basically, in my personal view, the status quo is not working."

Several transmission representatives, including Brenda Prokop of ITC and Tonja Wicks with Duquesne, agreed that PJM doesn't have to use the same process as other RTOs, which have given significant weight to cost caps.

"We think that PJM has the right view on this. We don't think that SPP and MISO have the right view on this," Prokop said.

"I think to some extent we have a blank sheet to say to FERC what we want their role to be — and ours," Glazer said.




Annual revenue requirement | *PJM*

## PJM NEWS

# PJM Monitor Seeks Reversal of MOPR Exemption

By Rory D. Sweeney

PJM's Independent Market Monitor last week filed a complaint with FERC requesting fast-track revocation of the RTO's decision to exempt a generator from a rule meant to combat market manipulation.

The complaint said PJM was "incorrect" in providing an unnamed generating unit with a competitive-entry exemption from the minimum offer price rule (MOPR).

The RTO developed the MOPR to prevent subsidized units from suppressing market prices by offering bids that are below a unit's competitive operational costs. The rule creates a price floor at which all new units must offer into the market unless they receive one of three types of exemptions from PJM. The competitive-entry exemption allows a unit to offer in at any bid, provided the generator can prove it receives no direct or indirect subsidies. (See *PJM: No Change on MOPR Yet; Remand May Have Little Impact*.)

"The stakes in this case are high. This generation is clearly not merchant generation, is clearly not competitive generation and represents exactly the type of subsidized generation that the MOPR was intended to address," the complaint said.

The complaint asks FERC to rescind the exemption before the generator submits "a noncompetitive offer" into any of PJM's Reliability Pricing Model auctions. The RTO holds annual Base Residual Auctions for capacity required three years into the future, along with incremental auctions each year leading up to the delivery year.

The Monitor declined to name the exempted generator to avoid disclosing market-sensitive information, but it described it as "a non-regulated company wholly owned by a parent company that wholly owns a regulated, vertically integrated electric utility." The Monitor told both the generator and PJM that the generator wasn't eligible for the exemption because it indirectly recovers costs from customers through a non-bypassable charge, according to the complaint.

Because the generator's construction was financed entirely by the parent, the cost of capital was lower than if the generator's operating company had sought financing on its own, the Monitor said, and that difference is the cost the generator indirectly recovered from customers through a non-bypassable charge.

However, PJM still granted the exemption.

The Monitor contended that allowing an exemption in this situation "would create a significant loophole" in the MOPR that would render it "ineffective" in similar situations because the unit is not "purely a merchant resource" as the exemption rule requires.

"Competitive market participants who invest in new generating facilities without the backing of a regulated utility or other nonmarket support" receive "essential protection" from the MOPR and would be "inappropriately disadvantaged" by the loophole, the complaint argues.

The issue was amplified by a July 7 decision from the D.C. Circuit Court of Appeals that vacated PJM's current MOPR provisions and remanded the order back to FERC. Among the topics at issue is one of the three MOPR exemptions, which PJM and its stakeholders had jointly requested that FERC eliminate.

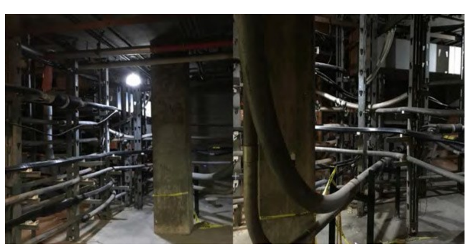
If FERC reverses its position and now decides to approve the request, that would make having an exemption more advantageous and the precedent of an approved loophole more problematic, the Monitor said. There would be just two exemption types, and the second — known as the "self-supply exemption" — is very limited.

"This would enhance the need for an effective MOPR and correct application of categorical exemptions to the MOPR," the complaint argues. "If the requested application of the competitive-entry exemption were approved, it would provide an easy way to avoid the defined limits on the self-supply exemption that applies to regulated utilities and to the utility in this case."

# PJM Board Approves $417M in Transmission Spending

The PJM Board of Managers on Wednesday approved about $417 million in reliability-related transmission projects, more than half of which will go to Public Service Electric and Gas to replace a substation in downtown Newark, N.J.

"The board's approval of these projects reinforces both PJM's fundamental mission of preserving reliability and the value of PJM's independent assessment of transmission needs," CEO Andy Ott said. "Planning is evolving in PJM to consider impacts of new trends. However, studying and planning for reliability remains the top priority."



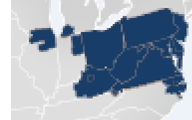
Newark substation interior | *PJM*

The PSE&G substation rebuild is expected to cost ratepayers $275 million. A new gas-insulated substation will be built adjacent to the existing station, which will be torn down. (See "New Proposal Shaves $78M from PSE&G Switch Fix," *PJM Planning Committee and TEAC Briefs*.)

The board also approved projects for American Electric Power, Dominion Energy, Atlantic City Electric, PECO Energy, Pennsylvania Electric, American Transmission Systems Inc., East Kentucky Power Cooperative, Exelon Generation and Dayton Power & Light. Most projects are estimated to cost less than $5 million, but a 31-mile reconstruction of a 230-kV line in Dominion's territory is expected to run $31 million. Two ATSI reconductor projects are estimated at a combined $33.43 million.

*— Rory D. Sweeney*

# PJM NEWS



# MRC/MC Briefs

## Markets and Reliability Committee

### PJM Tracking Pa. Virtual Transactions Tax

WILMINGTON, Del. — The Pennsylvania State Senate approved a tax on virtual transactions, moving the measure to the state's House of Representatives, PJM CFO Suzanne Daugherty told the Markets and Reliability Committee on Thursday.

Senators passed the tax on a 26-24 vote as part of a larger budget-funding package that includes several other consumer and corporate taxes. The Senate bill is the latest in a series of funding proposals after Pennsylvania legislators approved a budget by their constitutional deadline on June 30 but failed to agree on how to fund it. However, the Senate Appropriations Committee officially booked $0 for the PJM tax.

The state's interest in developing the tax came to light in mid-June, after PJM attempted to explain to Department of Revenue representatives the issues with levying a tax on RTO transactions. Daugherty alerted several PJM financial stakeholders, who launched their own advocacy efforts at the State Capitol, but ultimately blamed the RTO for not making them aware early enough to develop a comprehensive response. (See *Traders: PJM Delay Could Mean Pa. Tax; RTO Denies Supporting Levy*.) PJM remains opposed to any new taxes on its membership.

FirstEnergy's Jim Benchek asked Daugherty about PJM's plan to address the situation. She responded that the RTO will continue to watch the tax's progress and that it's "too early to see" how it might respond if the tax is implemented.

### Stakeholders Question Focus on DR in Seasonal Capacity PS

While aggregation rules allowed a substantial amount of seasonal resources to clear the 2020/21 Base Residual Auction as annual products, thousands of megawatts of such resources that have cleared past auctions didn't this time around. To address those situations, PJM is proposing a problem statement and issue charge, which received a first read last week.

PJM's Pete Langbein | © *RTO Insider*

However, stakeholders questioned the limitations PJM put on the scope of the analysis. The issue charge focuses on "the impact of peak-shaving resources on the load forecast" and exploring "non-capacity wholesale market mechanisms to value demand response resource flexibility."

"I struggle with why you're limiting this to nonmarket issues," said John Farber of the Delaware Public Service Commission.

Farber argued that adding market opportunities would spur innovation "so all stakeholders could get the benefit of managing that peak."

Several stakeholders, including American Municipal Power's Ed Tatum and Carl Johnson representing the PJM Public Power Coalition, asked why the documents focused on DR.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said his members are concerned about opportunities for residential customers, which he said have been "significantly limited" in recent years.

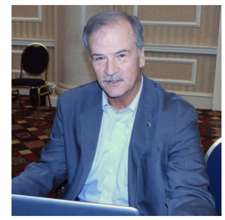
Organization of PJM States Inc. Executive Director Greg Carmean asked that PJM's education on the topic explain how the RTO came to develop the products it currently has and the impact of important legal decisions, such as *FERC v. EPSA*.

Tom Rutigliano, who consults with several energy management companies, requested that the analysis not be precluded from providing preliminary recommendations available for the next BRA in May 2018, despite a stated timeline that would provide results late next year.

PJM's Pete Langbein, who is overseeing the proposal, said he is open to any suggested changes.

"We're trying to be realistic about what it's going to take and not be overly aggressive," he said about the timeline.

### PPANJ's Jablonski Retires



Jablonski

Jim Jablonski announced he has retired as the executive director of the Public Power Authority of New Jersey. Jablonski, a former chair of the Members Committee, said it was a "pleasure and an honor" and a "humbling experience" to be involved in the PJM stakeholder process over the past decade.

He said some of the hardest issues he dealt with included the development of the minimum offer price rule and the Capacity Performance construct.

"It was a reaction to an anomalous event that may never, ever happen again, and we made these broad, sweeping changes to the capacity market that only increased costs to customers."

He said that while he agrees with the need for reliability, the people paying the bills need to be considered.

"I still am concerned about cost to customers," he said. "It seemed like every time we turned around here, we were raising costs to customers."

He has no immediate plans following retirement, but given his broadcasting background, he may consider media opportunities involved with PJM. He said he joked with PJM's Stu Bresler about starting a 24-hour PJM TV channel.

Brian Vayda, a former PJM employee, is succeeding Jablonski as executive director.

### Stakeholders Approve Variety of Actions

Stakeholders endorsed by acclamation several manual revisions and other operational changes:

- Manual 1: Control Center and Data Exchange Requirements. Revisions developed to comply with NERC reporting requirements. Transmission operators will be required to maintain certain data

*Continued on page 23*

# MRC/MC Briefs

Continued from page 22

during outages, including bus voltages for all 345-kV substations or higher and megawatt flows for all tie lines and all lines 345 kV or higher.

- Manual 11: Energy and Ancillary Services and Manual 18: PJM Capacity Market. Clarifies language on what is needed to qualify for exempt or bonus megawatts during performance assessment hours in Capacity Performance. PJM says it needs certain data to determine how close generators follow its schedule. The data include values for economic minimum and maximum and emergency maximum.
- Pseudo-tie *pro forma* agreement and Tariff and Operating Agreement revisions. The documents were developed to standardize pseudo-ties and minimize operating confusion. (See "OC Discusses Pro Forma Agreements for Pseudo-Ties, Dynamic Schedules," *PJM OC Briefs: July 11, 2017*.)
- Manual 14B: PJM Regional Transmission Process and Operating Agreement revisions. Redesigns to the Transmission Expansion Advisory Committee reflecting the change from the annual, 12-month Regional Transmission Expansion Plan cycle to an overlapping 18-month cycle beginning each September. The window for short-term projects will expand from 30 to 60 days. (See "RTEP Cycle Revisions Approved," *PJM PC/TEAC Briefs: July 13, 2017*.)

An endorsement vote on Tariff and Operating Agreement revisions to clarify the two-year limit on requests for billing adjustments was postponed to a later meeting.

## Members Committee

### Stakeholders Endorse Consent Agenda

Stakeholders endorsed by acclamation the committee's consent agenda along with several other Operating Agreement and Tariff changes:

- Tariff revisions related to the interconnection process regarding the alternate queue and cost allocation for projects less than $5 million. (See *PJM Considering Injection Rights for Demand Response*.)
- Pseudo-tie agreements and Tariff and Operating Agreement revisions. The documents were developed to standardize pseudo-ties and minimize operating confusion. (See MRC item 3 above.) Eighteen members opposed and six abstained.

### Stakeholders Endorse Regulation Changes Despite Continued Opposition

Stakeholders endorsed Tariff and Operating Agreement revisions to regulation market rules on performance scores, clearing and settlements that were previously endorsed by the Regulation Market Issues Senior Task Force and the MRC. The revisions change the rate for substituting traditional RegA and fast-response RegD. (See *PJM Regulation Compensation Changes Cleared over Opposition*.)

John Horstmann of Dayton Power and Light reiterated his past objection to the changes, which he said don't provide a sufficient transition period for the energy storage units developed for the original 15-minute neutrality requirement. However, the measured passed handily with 4.24 in favor out of 5 in a sector-weighted vote. Such votes require an approval of 3.33 (66.7%).

*— Rory D. Sweeney*

## SPP NEWS

# SPP to Dissolve Regional Entity

By Tom Kleckner and Rich Heidorn Jr.

DENVER — SPP announced last week it will dissolve its Regional Entity (RE), ending the reliability oversight role that had been a source of concern at NERC and FERC.

The RE is responsible for auditing and enforcing NERC reliability rules for 120 registered entities in three balancing authorities: SPP, Southwestern Power Administration and parts of MISO.

SPP said it was acting in part because of the expansion of its RTO footprint, which no longer aligns with the RE's territory. Since 2007, SPP's RTO has expanded to 14 states while the RE is limited to the original eight: all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas.

"Given that the footprints of the SPP RTO and SPP RE no longer align — due to our significant growth over the last decade and in light of further potential expansion opportunities to the west … SPP's executives, Board of Directors and Members Committee have made the strategic decision to focus on our core functions of reliability coordination, wholesale market operations and transmission planning," CEO Nick Brown said in a statement. "I believe this is in the long-term best interest of SPP and our members."

SPP said NERC had agreed to terminate the delegation agreement that appointed SPP as an RE in 2007. On July 23, the RTO's board and Members Committee voted to give Brown authority to terminate the delegation agreement, a decision the SPP RE Trustees endorsed the next day.

### Pressure from NERC?

SPP said it will work with NERC and FERC on the transition, which is expected to be complete by the end of 2018.

SPP sources said the decision came under pressure from NERC, which wanted to end RTOs' RE functions. Brown's statement said the decision had come "with the support and encouragement of NERC." NERC spokeswoman Kimberly Mielcarek told *RTO Insider* that NERC "supports this decision and will work with SPP to ensure a seamless transition."

SPP's dual role had also caused it problems with FERC, which criticized SPP in a 2008 audit for failing to ensure the RE's independence from the RTO (PA08-2, AD09-3). The audit called for improved oversight from the RE Board of Trustees to prevent conflicts of interest.

At the time, the RE had a budget of $4.6 million, for 12.4 full-time-equivalent employees, but it had only five full-time employees, with the remaining staff performing functions for both the RTO and RE.

In response to the audit, SPP agreed to eliminate all reporting relationships between RE and RTO employees. The RE now has 24 employees and a budget of about $10.8 million.

"We are going to move on," Brown said at last week's board and Members Committee meeting. "Each and every time we entered into [renewing NERC's delegated agreement], the relatively small size of the RE footprint and the connection between the RTO, the RE itself and our corporate compliance business [was an issue]. It was clear to us the continued renewing of that agreement was in jeopardy."

When NERC first delegated compliance monitoring and enforcement authority to its REs, half of them were affiliated with registered entities, according to SPP, which said it is the only remaining organization to operate as both an RTO and RE. "When SPP dissolves the SPP RE, only one of the eight [Regional Entities] will remain affiliated with a registered entity, and no ISO/RTOs will perform RE functions," SPP said.

### Transition

Mielcarek said SPP will provide a transition plan to NERC for review.

"The 120 registered entities within the SPP footprint will be notified of the dissolution and given the opportunity to submit a written request to transfer to another Regional Entity. NERC will determine whether the transfer is appropriate based on various criteria, including geographic location, electrical boundaries and resources," Mielcarek said.

All changes must be approved by NERC's independent Board of Trustees, then filed with FERC for its approval. "The outcome of this intensive process will result in a more efficient and effective [Electric Reliability Organization] Enterprise, and NERC looks forward to working with all affected parties," Mielcarek said.

Brown said the transition will take time. "It's

NERC Regional Entities | *NERC*

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## SPP NEWS

# Board Rejects Changes to Tx Zonal-Placement Rules

By Tom Kleckner

DENVER — SPP stakeholders made another effort to revise the RTO's transmission-zone placement process last week, but once again came up short when the Board of Directors sustained its earlier rejection.

The revision request's (RR172) defeat likely means future disputes over cost shifts caused by SPP's zonal-placement decisions will be resolved through litigation.

Buffington

"I'm not sure about next steps, but you can be sure it will be argued about at FERC in both current dockets and future dockets," Kansas City Power & Light's Denise Buffington told *RTO Insider*.

Several cases involving cost shifts are currently before FERC (ER12-959, ER16-204 and ER17-2020). Another (ER15-1499) has been settled between KCP&L and the City of Independence, Mo., and the terms are being phased in. After KCP&L objected to Independence being placed in its zone, the parties agree to phase in the city's annual transmission revenue requirement in three tranches ($3 million for June 2015-December 2016, $3.5 million for 2017 and $5 million for January 2018-May 2019).

Buffington has been the driving force behind RR172 for more than a year. She says there is a gap in SPP's process for placing applicant transmission owners (ATOs) in existing zones. Staff currently determine which of 18 transmission pricing zones to place new TOs, which can result in cost shifts for those in the incumbent zone.

"When SPP provides analysis to an impacted zone, SPP specifically states which zone the new TO comes into," Buffington said. "One of the issues in litigation is whether or not SPP should even make that decision. SPP has argued in litigation that that's within their scope and is their responsibility."

Buffington said she revised RR172 to incorporate that concept, saying it mitigates the costs of zonal-placement decisions and protects both existing and new customers from cost shifts by capping cost shifts for legacy facilities at 2% of the annual transmission revenue requirement or $1 million, and creating an 18-month period without cost shifts for the facilities following integration. It also would have provided an exclusion for legacy facilities that were jointly planned for the benefit of all customers in the zone.

"We're trying to isolate the cost of legacy facilities built outside the SPP planning process," Buffington said. "We want the board to give us some guidance on the policy. We feel we need some bookends around the cost structure, to help both existing and new members."

The revision had been through nine in-depth discussions in three stakeholder groups. Three weeks ago, it was rejected following a contentious discussion at the Markets and Operations Policy Committee, setting the stage for last week's appeal. (See *Divide Evident Between SPP Tx Owners, Users*.)

Public power entities led the opposition to RR172. Dave Osburn, general manager of

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# SPP to Dissolve Regional Entity

Continued from page 24

not something that's done overnight. A lot of coordination has to occur between the SPP RE and the audits we have underway."

Brown said there will be "much debate in the Members Committee" about the transition to another RE, and that NERC will facilitate many of the meetings.

### 24 Employees Affected

The RTO said it was "committed to ensuring the continued employment" of the 24 RE employees. "There's a lot of interest in those employees," Brown said. "They've done exemplary work over the last decade and are noted as experts by a number of professional entities."

Dave Hudson, president of Xcel Energy's New Mexico and Texas operations, complimented the RE staff on behalf of the members: "They are very professional in a hyper-technical area, and we appreciate working with them. The world changes, but these people are very competent and have a bright future in front of them."

Dave Christiano, chair of the RE Trustees, responded: "They're highly educated and highly prepared. A lot of our people are certified, which isn't generally the case with other REs. We're working with the other REs and NERC to ensure a good future for our employees."

### Mountain West: No Impact

SPP's RTO footprint expanded first with the addition of the Nebraska entities in 2009 and the Integrated System in 2015. SPP is currently wooing the Mountain West Transmission Group — two investor-owned utilities; two municipal electricity providers; two generation and transmission cooperatives; and two federal power marketing administration projects covering most of Colorado and Wyoming, along with parts of Nebraska, New Mexico, Arizona and Montana — to join the RTO. Adding Mountain West would mean including in the RTO's Tariff all the DC ties between the Eastern and Western Interconnections, except for one in Canada. (See *SPP, Mountain West Members Get Acquainted*.)

Mark Stutz, spokesperson for Xcel Energy's Colorado utility, said the dissolution of the RE will not impact Mountain West's decision on joining the SPP RTO. "It is really an issue more local to the area in which it is occurring. The function of the Regional Entity (RE) is essentially one of standards compliance and enforcement. In the MWTG footprint, that's currently handled by the Western Electricity Coordinating Council (WECC); if [a] regional transmission organization is formed in the Mountain West, this function still would be handled by WECC."

*[Editor's Note: Editor-in-Chief Rich Heidorn Jr. participated in the 2008 audit of the SPP Regional Entity as a member of FERC's Office of Enforcement.]*

## SPP NEWS

# Board Rejects Changes to Tx Zonal-Placement Rules

*Continued from page 25*

the Oklahoma Municipal Power Authority, was among those signing a letter that was submitted four days before the board meeting. The letter, co-signed by Golden Spread Electric Cooperative and Northeast Texas Electric Cooperative, charged "KCP&L has been transparent that the RR172 process, and the expected failure, is simply a prerequisite" to a Section 206 complaint at FERC.

"One of the concerns we have on this is as a transmission-dependent utility, we should be careful to not approve something that keeps the smaller entities from building transmission and getting cost recovery," Osburn said during the discussion. "We've been paying a load-ratio share of transmission customers for quite a while. Some assets in existing transmission zones may not benefit all customers either, but we pay our load-ratio share regardless. The money we pay is just as important as the TOs'."

"This is an additional burden for a new ATO. They are going to have to present a lot of data people haven't in the past," said NTEC Vice President Jason Atwood. "It concerns me we're always talking about expanding the footprint. The concern about something like this is it could impact the expansion."

Nebraska Public Power District's Paul Malone, whose company is involved in one of the FERC dockets, wondered aloud whether there was an ulterior motive to the current zonal-placement process.

"Costs shifts are not a one-time issue. They come back year after year," Malone said. "Are the new members joining because they expect someone else to pay for their system? Is that the windfall to entice them to join? I hope not."

"We're all trying to do the right thing for our customers. They're the ones impacted by these cost shifts," Buffington said. "Nothing in this proposal is intended to prevent entities from collecting the revenue requirement. It's all about which customers pay."

The Members Committee approved RR172 by a 11-9 vote. However, the board voted against the motion.

Midwest Energy's Bill Dowling was among those supporting RR172, though he was reluctant to change the Tariff language.

"That gives us the flexibility to continue to adjust the process, especially when some of the issues around cost mitigation and cost shifts are still in flux," he said. "It's been an issue, and it continues to be an issue."

"It's not the end of the story," SPP Board Chair Jim Eckelberger said. "There was a suggestion to let some time pass and see what we learn from it. That may be one answer to it, but sooner or later, if nothing is forthcoming and the problem still exists — and I think it's a problem — we'll have to assign the problem to someone."

"We'll continue to work with the stakeholders to find a path forward," Buffington said. "I don't know if that will be in a FERC proceeding or through the stakeholder process, but we'll do some work on that."

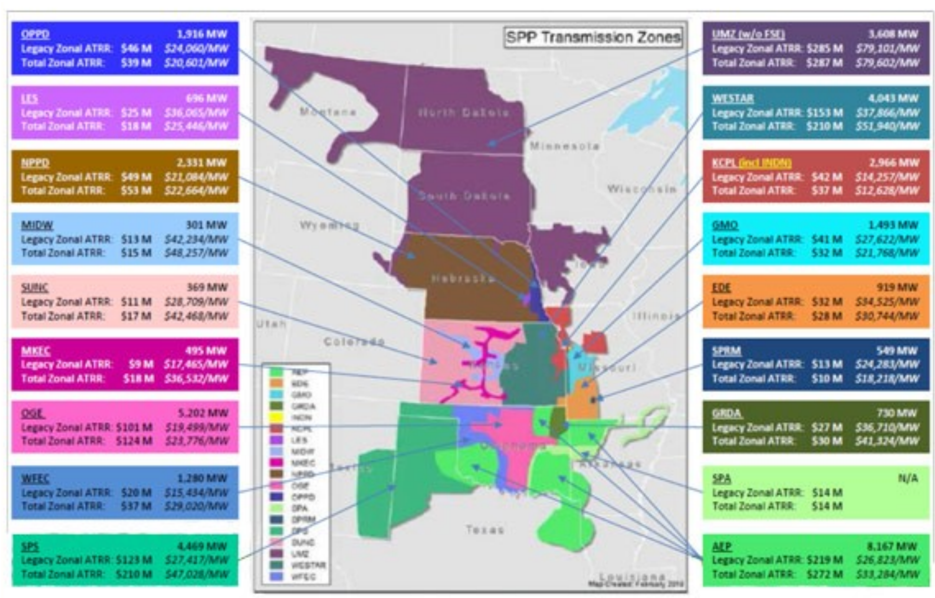
The board did approve a four-step communications process for SPP staff to follow in making zonal placement decisions. The Transmission Owner Zonal Placement Process document addresses the growth of transmission zones in SPP's footprint and concerns expressed over the process in FERC proceedings. (See "SPC Approves Zonal Placement Process Document," SPP Strategic Planning Committee Briefs: July 13, 2017.)

However, Buffington found little solace in the document's passage.

"The process document does not solve any of the underlying issues," she said, referring to her concerns about a lack of notice and transparency. "SPP has used informal criteria to determine which zone to place a new entity in. They've never included cost impacts in their solution. The process lacks transparency and harms existing customers."

Arkansas Electric Cooperative Corp. CEO Duane Highley reminded the board and members that his company's long-time stakeholder representative, the recently retired Ricky Bittle, always believed SPP should consist of one zone.

"Maybe the time for Ricky's dream has come," SPP Director Phyllis Bernard said. "It seems the difficulty of this whole issue, trying to talk through it and work it out, has seemed to be intractable. It seems to take up so much resources, good will, time and results that no one is satisfied with it. A [single postage-stamp] rate is a worthy goal to work towards."




Current SPP transmission pricing zones. Zonal ATRR and load information based on data in RRR file for rates effective April 1, 2017. | *KCP&L*

## SPP News

# Board/Members Committee Briefs

### Z2, Two Other Task Forces Expire

DENVER — The SPP Board of Directors and Members Committee approved the Markets and Operations Policy Committee's decision to allow the Z2, Export Pricing and Gas-Electric Coordination task forces to expire. (See related story, *SPP Moves Ahead with 'Tweaked' Panhandle Congestion Study*, p.30.)

Stakeholders also approved two recommendations from the Z2 Task Force. The first eliminated credits for non-capacity upgrades, such as substation facilities, while the second disposed of credits for short-term transmission service of less than a year.

The motion passed the Members Committee with two "no" votes (NextEra Energy Resources and Oklahoma Municipal Power Authority) and an abstention (ITC Holdings).

However, in nearly a year of work, the task force was unable to reach consensus on simplifying the vexing process spelled out in Attachment Z2 of SPP's Tariff, in which financial credits and obligations are assigned for sponsored transmission upgrades. The group expressed "significant concern" over SPP's existing congestion rights processes and the "perceived lack of hedging" but was unable to reach consensus on using incremental long-term congestion rights (ILTCRs) to replace Z2 credits.

"With respect to transparency, neither of these two changes does anything to move the ball forward," said NextEra's Aundrea Williams. "The vast majority of the task force agreed there was a better market solution out there but couldn't support it. Perhaps when the TCR market is improved, that's the time to look at the Z2 process."

During the MOPC meeting last month, members learned staff would have to resettle nine years of historical Z2 credits and obligations because of billing disputes, "minor" software defects and problems in calculating the present value of creditable balances. (See "More Z2 Woes; SPP to Resettle 9 Years of Data," *SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017*.)

### Board Reaffirms Seams Project with AECI

Unfazed by a nearly 50% cost increase, stakeholders reaffirmed their endorsement of the proposed $13.75 million seams project with Missouri-based Associated Electric Cooperative Inc. (AECI).

Golden Spread Electric Cooperative and Southwestern Public Service opposed the project, while NextEra and American Electric Power abstained.

The project involves installing a new 345/161-kV transformer at AECI's Morgan substation and an uprate of a related 161-kV line, both near Springfield, Mo.

Nickell attributed the project's increase to an increase in the amount of work needed to upgrade the 161-kV line. Staff's cost-benefit re-evaluation of the project since last month's MOPC meeting has shown SPP will still receive most of the benefits. (See "Staff to Review AECI Joint Project After Cost Increase," *SPP Markets and Operations Policy Committee Briefs: July 11-12, 2017*.)

Based on the amount of unforeseen work, AECI has agreed to increase its share of the project's cost to 10.9%, or $1.5 million. SPP will bear the remaining $12.25 million.

The project would be regionally funded, as it solves congestion issues on SPP's side of the seam. It is contingent on reaching an agreement for compensating AECI, which will own the project and be responsible for its construction, operations and maintenance.

### Brown: SPP has Good Story for Congress

Previewing testimony he would deliver to a Congressional energy subcommittee the

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SPP NEWS

# Board/Members Committee Briefs

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day after the board meeting, SPP CEO Nick Brown said he had a good story to tell. (See related story, *RTOs to Congress: Don't Lose Faith in Markets*, p.1.)

"SPP is obviously one of the nation's RTOs that has been successful in reliably implementing a significant amount of wind," he said. "We have been very successful at reliable operations because of three specific actions we have taken over the last decade."

Those actions, Brown said, included SPP's $10 billion infrastructure build, deploying a day-ahead market for unit commitment and consolidating 18 balancing authorities into a single entity.

"Take any of the three away, and we would not be where we are today," he said. "Make no mistake, we have been very successful because of the bold moves our members have taken over the last decade."

## Vote on FERC Nominees Possible in August

FERC's Patrick Clarey said the U.S. Senate's shrinking August recess may give the body time to act on nominees waiting to join the five-person commission, which currently consists of acting Chair Cheryl LaFleur.

Republicans Robert Powelson, a Pennsylvania commissioner, and Neil Chatterjee, energy adviser to Senate Majority Leader Mitch McConnell (R-Ky.), advanced out of the Senate Energy and Natural Resources Committee in June on the strength of 20-3 votes. A confirmation vote by the full Senate has not been scheduled, but it is on the executive calendar, Clarey said.

"There could be a vote any time," he said.

The White House has said President Trump intends to nominate Republican attorney Kevin McIntyre as chair and Richard Glick, the Democrats' general counsel for the committee, to fill the remaining two spots on the commission. (See *Trump Names Energy Lawyer McIntyre as FERC Chair*.)

However, McIntyre and Glick's official paperwork has yet to be submitted, Clarey said.

FERC has been without a quorum since Chairman Norman Bay stepped down in February. Colette Honorable left the commission when her term expired June 30.

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## Oversight Panel Members to Serve as Liaisons with SPP Officers, Businesses

Oversight Committee Chair Joshua W. Martin III said the committee's members will "establish ongoing contact" with SPP officers and staff and oversee defined areas of responsibility.

The liaisons are: Harry Skilton (internal audit), Phyllis Bernard (compliance), Graham Edwards (Market Monitoring Unit) and Bruce Scherr (security).

In another personnel-related action, Brown notified members that NextEra's Williams, Duane Highley (Arkansas Electric Cooperative Corp.), Dave Osburn (Oklahoma Municipal Power Authority), David Hudson (SPS), Philip Crissup (Oklahoma Gas & Electric) and Jon Hansen (Omaha Public Power District) have all reached the end of their terms on the Members Committee. With the exception of Crissup and Hansen, all have chosen to run for re-election.

## Consent Agenda Includes 8 Revision Requests

Members and the board unanimously approved a consent agenda that included eight revision requests and several other items:

- MWG-RR185: Clarifies which SPP criteria document (Planning Criteria or Operating Criteria) is referenced when used in the market protocols and the Tariff's Attachment AE, and directs users to the correct document.
- MWG-RR82: Ensures combined cycle units avoiding outage deviation penalties and do not lose eligibility for start-up cost make-whole payments (MWPs) because of physical or environmental limitations. Adds a previously discussed increase in the MWPs' grace period for commitments from one hour to two hours. The revision's implementation date was scheduled for this August to allow SPP to complete development of software that allows market participants to register and submit separate offers for each of the combined cycle units' multiple configurations.
- MWG-RR222: Includes a multi-configuration combined cycle resource's (MCR) committed and actual configuration for each interval in a bill determinant report, allowing MCRs to shadow the configuration SPP is using to settle these resources.
- MWG-RR225: Cleans up confusing and misleading Tariff language on ILTCRs that could have construed ILTCRs as load-serving entities or non-LSEs.
- MWG-RR226: Changes settlement location pairs that have potential for unconstrained flow to electrically equivalent settlement locations during the auction revenue rights process to comply with a FERC order (ER17-310). SPP will post the settlement locations before the annual ARR allocation process, along with the system topology and other data.
- MWG-RR229: Satisfies FERC Order 831's requirements on energy offer caps by using actual costs for MWPs on offers above $1,000/MWh. According to the order, costs underlying a resource's cost-based incremental energy offer above $1,000/MWh must be verified before that offer can be used to calculate LMPs.
- ORWG-RR228: Clarifies existing planning criteria language for system operating limits to reduce the potential of misinterpretation by entities complying with NERC reliability standards.
- RTWG-RR233: Ensures that eligible network customers will not be billed twice for the same deliveries by not assessing charges against a specific use of an owner's facilities that do not receive the benefit the charges provide to other transmission owners.

Also approved on the consent agenda:

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## SPP News

# Regional State Committee Briefs

## RSC Leaves Safe Harbor Limit Unchanged

DENVER — The SPP Regional State Committee unanimously agreed last week with its Cost Allocation Working Group to leave the aggregate study's safe harbor cost limit unchanged at $180,000/MW.

The study assesses which projects are necessary to satisfy transmission service requests (TSRs) to move energy around the SPP system, as well as who pays for those projects. Transmission upgrades under the safe harbor limit are base-plan funded through the RTO's highway/byway approach.

The safe harbor is applied when the aggregate study's waiver criteria are met:

- The utility does not have more than 20% of its designated resources (used to meet a load-serving entity's capacity margin requirement) come from wind energy when the TSR is granted.
- It has a five-year minimum commitment term for the TSR.
- The utility does not have designated resources greater than 125% of its forecasted load when the TSR is granted.

SPP has not recommended a change to the safe harbor amount since it was first established in 2005. Staff does file an annual letter at FERC (ER05-652), testifying as to whether the amount is correct.

Adam McKinnie, chief regulatory economist with the Missouri Public Service Commission and the CAWG's chair, said an annual limited review of the safe harbor could include a discussion of the FERC letter and the methodology behind SPP's recommendation on whether to change the amount.

CAWG members, staff and stakeholders have been discussing the correct methodology for calculating the limit. No consensus has been reached, but the discussions continue, McKinnie said.

The RSC also agreed with the CAWG to review the base-plan funding eligibility criteria and the safe harbor limit on an annual basis, with in-depth review at least once every five years. Both votes were unanimous.

The group just spent two years conducting the first review of the safe harbor waiver criteria. McKinnie estimated it would take nine to 12 months to conduct intensive reviews of safe harbor issues in the future, while a limited review could be done during a quarter and focus on issues of interest to the RSC or stakeholders.

"Frankly, we don't want this to be our full-time job," John Krajweski, a consultant with the Nebraska Power Review Board, told the RSC.

The Kansas Corporation Commission's Shari Feist Albrecht agreed, saying, "The motion provides sufficient flexibility and doesn't impede the RSC's ability to request a study."

## SPP Wind Capacity Nears 17 GW

Bruce Rew, SPP's vice president of operations, said the RTO is continuing to successfully integrate large amounts of wind energy.

The RTO currently has 16,280 MW of installed and operational wind capacity, with another 100 MW of wind registered but not yet operational. It expects another 5 GW to become operational before production tax credits expire in 2020, and it has another 18 GW in its interconnection queue.

SPP set a record for North American RTOs in April when it recorded a 54.47% wind

Oklahoma Commissioner Dana Murphy makes her point as SPP CEO Nick Brown and New Mexico Commissioner Patrick Lyons listen. | © *RTO Insider*

penetration level. Rew noted SPP had not seen wind penetration levels of 40% until last Christmas. It exceeded 40% for seven days in the first quarter, and another seven days in April.

SPP's Integrated Marketplace currently has 191 market participants, up from 172 a year ago, with 125 classified as financial-only and 66 as asset-owning. Rew said the RTO lost a financial-only entity during the second quarter.

The RTO's balancing authority has successfully maintained NERC control performance standards while maintaining high system availability, he said. The day-ahead market's posting has not been delayed during the last year, Rew said, and the real-time balancing market has successfully solved 99.95% of all intervals.

## Interested Observers: Colorado's PUC

Colorado Public Utilities Commission Chairman Jeff Ackermann and Commissioners Frances Koncilja and Wendy Moser were guests of honor and given front-row seats for the July 24 RSC discussion.

SPP CEO Nick Brown welcomed the commissioners, along with the new members of the RSC.

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# Board/Members Committee Briefs

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- The scope for the expedited re-evaluation of the Kummer Ridge-Roundup 345-kV line. (See "MOPC Endorses Re-evaluation of Basin Electric Project," *SPP Markets and Operations Policy Committee Briefs*.)
- A request that FERC waive SPP rules to allow restating of settlement prices for TCRs at Omaha Public Power District's Fort Calhoun nuclear plant site. The plant was retired Dec. 1, 2016, but incorrect modeling of shift factors from Dec. 1 to Dec. 14 resulted in the marginal congestion component being overstated and the TCR settlements sourcing at the location being understated.

*— Tom Kleckner*

## SPP NEWS

# SPP Moves Ahead with 'Tweaked' Panhandle Congestion Study

*By Tom Kleckner*

DENVER — SPP's on-again, off-again high-priority congestion study of the Texas and Oklahoma panhandles region is on once again following approval by the Board of Directors.

The study, ordered by the board in April to address historical congestion and frequently constrained areas (FCAs) in western Oklahoma and Texas caused by large amounts of wind energy, met pushback from the Markets and Operations Policy Committee three weeks ago. It was then revived with new direction by the Strategic Planning Committee later in that week. (See "Committee Gives Congestion Study New Life," *SPP Strategic Planning Committee Briefs: July 13, 2017*.)

When SPP Vice President of Engineering Lanny Nickell presented a revised study scope to the board and members based on stakeholder feedback last week, he said he couldn't recommend proceeding with the study.

"It's to the point where the scope is so watered down now, I don't think you're going to get any value out of it," Nickell said. "If you want to do a study, let's do it right."

Kelly Harrison, Westar Energy's vice president of engineering, agreed, pushing for a more in-depth analysis that would provide that value to the market.

"If we could get some type of study to determine what it would take to move wind out of SPP — maybe to somebody who wants to buy that wind — it might send a price signal of what it would cost to move that wind with firm transmission," he said. "Right now, [developers] don't know what to pay. A longer study would give us a goal post and send a signal to the marketplace. We're putting states in a bind with what I think is a pretty valuable resource."

Nickell suggested a compromise by "tweaking" the scope of the 2018 integrated transmission plan near-term (ITPNT) assessment currently underway to include a summer scenario that models large amounts of wind. Stakeholders have taken the model out of previous studies because of concerns of "too much wind in the model for a summer-peak condition," he said.

"It may make sense to reassert that model and use it in the 2018 ITP near-term, if evaluated against other needs," Nickell said.

"That satisfies me!" board Chair Jim Eckelberger said.

Stakeholders agreed using the 2018 ITPNT would produce more timely results and reduce the drain on staff resources already engaged in regular studies. Staff's workload is sure to be exacerbated should the Mountain West Transmission Group integration proceed. The ITPNT study is to be completed no later than April 2018. (See *SPP, Mountain West Members Get Acquainted*.)

"I don't want anyone to forget why this began," said West Texas-based Golden Spread Electric Cooperative's Mike Wise. "The genesis of this discussion is based on … endemic congestion north and south of [Southwestern Public Service] and the continuation of a FCA south of there.

"Find me a solution. That's what I've been asking for … for 10 years. I'm waiting for when the congestion goes away," he said. "One of your members here is crying out. Please, please, let's get this FCA taken care of, and don't forget us."

The Members Committee endorsed the revised high-priority study 10-8, with two abstentions. The board also voted in favor of the new study approach.

Work to improve SPP's transmission congestion rights market will continue in the Market Working Group.

Separately, the board and Members Committee approved the expiration of the Export Pricing Task Force, which was charged with evaluating "mechanisms to establish equitable and not unduly discriminatory prices" to ship electricity in and out of SPP's footprint. The task force was unable to provide a recommendation to handle the RTO's growing wind energy (23 GW in the interconnection queue and not in service).

"We determined there are no really good solutions. There's no silver bullet, so to speak," said Wise, the group's chair. "We asked for views on potential solutions that doesn't, in the end, have SPP consumers footing the bill. The consumers that benefit from this wind are going to need to pay for the transmission."

That was before AEP's announcement it would build a 2,000-MW wind farm in western Oklahoma and send the energy eastward. (See related story, *AEP to Spend $4.5B on Largest Wind Farm in US*, p.1.)

# Regional State Committee Briefs

*Continued from page 29*

"It's always been a strategy for SPP, and one we identify every strategic cycle, to maintain and establish a good relationship between staff and the RSC," Brown said. "We've recognized for more than a decade how important it is to get you engaged in the process."

The Colorado PUC will be among the bodies passing regulatory judgment on the Mountain West Transmission Group's potential membership in SPP. The commission has held two public information sessions on the merger and has scheduled a third for Aug. 24. (See *SPP, Peak Reliability Pitch RC Services for Mountain West*.)

"The [Mountain West] expansion is an important decision, not only for the 10 members of the Mountain West, but for SPP as a whole," Brown said. "We encourage you to stay engaged."

*— Tom Kleckner*

Colorado's commission takes in the RSC meeting (left to right): Wendy Moser, Chairman Jeff Ackermann, Frances Koncilja | *© RTO Insider*

## Q2 EARNINGS

# Eversource Earnings up on Tx, Distribution

By Michael Kuser

EVERSOURCE Eversource Energy's second-quarter profits this year increased 13.3% over the same period a year ago, driven mainly by higher distribution revenues and lower operations and maintenance expenses.

The company reported net earnings of $230.7 million in the second quarter of 2017, compared to $203.6 million a year earlier. In a July 28 earnings call, CFO Phil Lembo highlighted the company's transmission expansion plans, and its move away from electricity generation and into the water industry with its planned $1.7 billion acquisition of water utility Aquarion Water, which operates in Connecticut, Massachusetts and New Hampshire. Eversource expects to close the deal by year-end following regulatory approval.

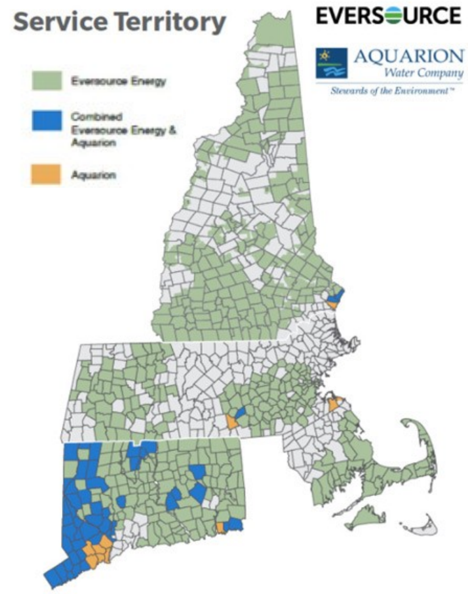
### ROE Revisited

Lembo commented on the D.C. Circuit Court of Appeals' April ruling overturning a 2014 FERC order that lowered the base return on equity for New England transmission owners from 11.14% to 10.57%. The court said the commission failed to meet its burden of proof in declaring the previous 11.14% rate unjust and unreasonable. (See Court Rejects FERC ROE Order for New England.)

In June, the New England TOs — including Eversource — filed with FERC to begin billing customers based on the prior ROE, with retroactive billing to June 8 of this year, 60 days after FERC assembles a quorum.

The commission has lacked the necessary three-member quorum since the February

A Hydro-Quebec HVDC converter




Eversource Energy

departure of former Chair Norman Bay and has been down to one commissioner — acting Chair Cheryl LaFleur — since Colette Honorable left last month. LaFleur may be joined by four new members if Democrat Richard Glick and Republicans Kevin McIntyre, Robert Powelson and Neil Chatterjee win Senate confirmation. (See Trump Names Energy Lawyer McIntyre as FERC Chair.)

"As a reminder, every 10 basis points [0.1%] of change in transmission ROEs results in about $3 million after-tax earnings annually," Lembo said. The posted Q2 earnings reflect the lower ROE rate ordered by FERC.

### Northern Pass

Company executives also touted the benefits of a proposed project designed to help Massachusetts meet its ambitious clean energy goals.

Eversource and Hydro-Québec on July 27 jointly bid the Northern Pass transmission line into the state's solicitation. The 192-mile line would carry 1,090 MW of Canadian hydropower into New England and deliver up to 9.4 TWh/year for a period of 20 years starting in December 2020. The RFP encouraged bids able to begin delivering all or part of the state's required 9.45 TWh/year of renewable energy by the end of 2020. (See Hydro-Québec Dominates Mass. Clean Energy Bids.)

New Hampshire's site evaluation on Northern Pass is moving forward this summer, and the company estimates the project will be fully permitted by the end of September, allowing construction to start in early 2018, Executive Vice President Lee Olivier said.

"We believe this schedule would put us ahead of any other major project to import Canadian hydro into New England," Olivier said. "Our confidence in the construction schedule is also supported by the firm contracts we have with two of the most preeminent firms in the world in terms of electric transmission design and construction, ABB and Quanta Services."

Bay State Wind, a 50/50 partnership between Eversource and DONG Energy, will also bid into a separate wind project RFP in December to develop an offshore site south of Martha's Vineyard.

### Regulatory Activity

The company also noted that Massachusetts regulators last month wrapped up hearings on rate cases filed by Eversource subsidiaries NSTAR Electric and Western Mass Electric, which have asked to raise their base distribution rates by $60 million and $36 million, respectively. Eversource also sought approval to combine the two utilities.

"Hearings have concluded on the rate case, except for rate design topics," Lembo said. "We expect a decision on the financial aspects of the case by the end of November, with the rate design decision around year-end. New rates would be effective in January of 2018 and to date we've had no surprises in the rate review process."

In New Hampshire, binding bids to buy the company's Public Service of New Hampshire generation fleet are due in August. "There, too, the overall divestiture process is moving along well and we expect regulatory approval of the sale by the end of the year, with securitization activities to follow soon after the closing," Lembo said.

# Q2 EARNINGS

## NextEra Seeks $275M Fee for Failed Oncor Bid

*By Tom Kleckner*

NextEra Energy CEO Jim Robo said Wednesday that the Florida-based company would "vigorously" pursue a $275 million termination fee it says it is owed following a failed attempt to acquire Texas utility Oncor.

The Public Utility Commission of Texas in April ruled that NextEra's $18.7 billion acquisition of the state's largest utility wasn't in the public interest, and then rejected two subsequent rehearing requests. Warren Buffet's Berkshire Hathaway Energy has since announced it has reached an agreement to buy Oncor's parent, bankrupt Energy Future Holdings (EFH), which would give it control of Texas' largest utility. (See *PUCT Staff Welcomes Buffett's Oncor Bid; Debtor Miffed*.)

During a conference call with financial analysts following the company's release of second-quarter earnings, Robo said the termination fee was triggered when


Robo

NextEra was unable to agree to a list of what it called "burdensome conditions," which included protective ring-fencing around Oncor and an independent board of directors for the company.

"The agreement has been terminated by EFH … in that the burdensome conditions had not been satisfied, which was one of the precursors to obtaining regulatory approval," Robo said. "As a result of the termination of merger agreement, we will vigorously pursue our rights to termination of the fee."

NextEra has also filed a lawsuit in Texas state court against the PUC, asking the court to reverse the regulators' rejection of the proposed acquisition. Robo declined to address the lawsuit, saying the petition it filed "speaks for itself." (See "NextEra Sues over Regulators' Rejection of Oncor Acquisition," *Company Briefs*.)

Asked about the Department of Energy's grid reliability study and its focus on baseload power, Robo said it was too early to speculate about the final report's conclusions. He said the "data is pretty clear" that the grid does not have any reliability issues.

"The facts are, the grid is very reliable in America right now, particularly as storage prices come down and make renewables more reliable," he said. "Our industry has a choice of hanging on to the techs of the past or adopting and embracing the technology of the future. We know what our strategy is. We're going to embrace renewables and embrace them hard."

NextEra reported an 11% increase in adjusted earnings during the second quarter, from $777 million last year to $881 million this year. Earnings per share were $1.86, up from $1.67, beating Nasdaq's consensus analysts' forecast of $1.76.

The company's stock price jumped almost 2%, from $142.62/share to $145.35/share, after the market opened. It was trading at $144.94/share by late afternoon.

## PSEG Sees Support for Nuclear Plants, Will Seek Revenue Decoupling

*By Peter Key*

Public Service Enterprise Group CEO Ralph Izzo said last week that the company has received "just about universal support for the continued operation" of its nuclear plants.

Speaking during the company's second-quarter earnings call on Friday, Izzo also revealed that PSEG's Public Service Electric and Gas plans to ask the New Jersey Board of Public Utilities to decouple its distribution revenue from its sales volume to enable it to support large-scale investments in energy efficiency.

PSEG — which owns the Hope Creek Generating Station and 57% of the adjacent Salem Nuclear Generating Station in New Jersey, and 50% of the Peach Bottom Atomic Power Station in Pennsylvania — wants financial compensation for its emissions-free generation, which it says is at risk from low power prices.


Izzo

Izzo said it's good that the Department of Energy recognizes a challenge "with baseload generation and fuel diversity," which will be the subject of a report the department plans to release soon. He called "the recent PJM proposals on how to deal with inflexible units … potentially quite helpful." (See *PJM Stakeholders See Capacity Auction Flaws, Offer Solutions*.) Izzo also said the recent court decisions supporting zero-emission credits (ZECs) in Illinois and New York "have solidified the fact that the states have the ability to act in these matters, and that's good news." (See related story, *New York ZEC Suit Dismissed*, p.19.)

Still, Izzo said, "the problem, according to the forward price curve, is at New Jersey's doorstep, and there's no denying it." As a result, he said, PSEG will "continue to educate stakeholders at the state level about the need to preserve the diversity and resiliency of our electric generating mix."

PSE&G will make the decoupling request in a rate case it plans to file no later than Nov. 1. A growing number of utilities are seeking to decouple their revenue from their sales. The move enables them to get the money they say they need to maintain their infrastructure even if their sales are flat or declining. In California, for example, utilities receive incentives to encourage their customers to use renewables and conserve electricity.

PSEG earned $109 million ($0.22/share) in the quarter, down from $187 million ($0.37/share) in the second quarter of 2016. The company said its most recent figures were affected by accelerated depreciation associated with the June 1 retirement of its last two coal-fired generating stations. PSEG's revenue in the most recent quarter was $2.13 billion, up from $1.91 billion a year ago.

## Q2 EARNINGS

# FirstEnergy CEO Says Country Heading for Natural Gas 'Disaster'

*By Peter Key*

Speaking in apocalyptic terms, FirstEnergy CEO Chuck Jones said Friday that he thinks the "country is heading for a disaster" because of its over-reliance on natural gas for generating power.

In response to a question during FirstEnergy's second-quarter earnings conference call, Jones said one type of disaster "could be a national security type of issue. We are taking the most sophisticated bulk electric system that exists anywhere in this world and putting it on top of a bulk gas system that is very unsophisticated, and that sets up security risks if there were ever an attack on that bulk gas system."

The other type of disaster, he said, could be economic. "We are getting to where we are relying too much on one fuel source for the generation of electricity, and I think fuel diversity is critical to keeping economic stability. With where gas is priced now, if anything happens to cause that gas price to go up again and create a volatility in the gas markets, the volatility in electric markets is going to be so great that I don't think industry in our country is going to be able to tolerate it."

There's no doubt that cheap gas has been disastrous competition for FirstEnergy's aging merchant generation fleet. The company lost $1.1 billion in the second quarter of last year, largely because of the closure of five uneconomic coal plants. The company earned $174 million ($0.39/share) on revenue of $3.3 billion in 2017's second quarter.

FirstEnergy plans to exit the competitive generation business and focus on its regulated utility operations by selling its generation units or getting them classified as regulated assets on which it is guaranteed a rate of return. The company's FirstEnergy Solutions (FES) subsidiary owns 15 power plants, including three that use nuclear fuel and four that are coal-fired, and low natural-gas and falling renewable energy prices have battered it so badly that Jones has considered having it file for bankruptcy protection. (See *FirstEnergy Wants out of Competitive Generation*.)

In last week's earnings conference call, Jones said FES will be talking with a group that says it represents more than 80% of the unit's creditors and that he will be taking part in the conversation. Jones said the group called FES and "outlined a formula for a potential discussion that was interesting

*Continued on page 34*

## Calpine Confirms Acquisition Talks

Calpine CEO Thad Hill confirmed Friday that the Houston-based merchant generation company is looking to be acquired. Citing anonymous sources, Bloomberg reported on Wednesday that Energy Capital Partners is in advanced talks to purchase Calpine and could announce a deal as soon as this week.

During a call to discuss second-quarter results, Hill said that "the public equity markets have undervalued our business and underappreciated our strong track record of executing on our financial commitments and our stable cash flows."

The company's board of directors decided to explore "strategic alternatives" in early spring, Hill said. Executives do not plan to provide updates on sale discussions unless required by law and do not know if they will result in any sale.

Calpine's adjusted second-quarter profit was $419 million, compared with $452 million during the same period last year, an 8% drop. Profit for the first half of the year was $745 million, compared with $826 million in 2016.

The company saw higher peak-time prices for its Texas plants in the constrained Houston zone, and PJM's most recent capacity auction yielded good results for the company's plants there.

"The larger storyline in the east is the integrity of their market structures given the potential for nuclear bailouts in some states and the pursuit of renewables in others," Hill said.

CAISO is exploring reliability-must-run agreements with Calpine to keep its 47-MW Yuba City and Feather River peaking units operational. (See *CAISO Seeks Reliability Designations for Calpine Peakers*.)

Calpine lists as current assets its 80 power plants in operation or under construction in 18 states, totaling about 26 GW of capacity. Company executives elected not to take questions from analysts regarding the second-quarter results.

## PG&E Files $74M Transmission Charge

Pacific Gas and Electric parent company PG&E Corp. reported that its profits rose by 97% to $406 million on a non-adjusted basis compared with the same period a year ago. The increases resulted from resolution of its 2017 electric and transmission and storage rate cases, the company said.

During a July 27 earnings call, CEO Geisha Williams said the company had filed with FERC for a $74 million transmission revenue increase beginning next year for reliability work and modernizing substations.

"It is through these types of investments and these continued investments in our grid that we can help ensure our system is stable and that we can continue providing the high-quality service that our customers have come to expect," Williams said.

The company's 2,240-MW Diablo Canyon nuclear plant was in planned refueling when a scorching heat wave hit California, and nearly 2% of customers lost power on a peak day. At times during the heat wave, renewable portfolio standard-qualified resources made up more than half of energy supply, Williams said.

PG&E received 98% of its rate base request in its general rate case, representing an 1% increase in authorized revenue for 2017. It expects a decision later this year on a settlement filed with the California Public Utilities Commission on its proposal to retire Diablo Canyon. The company in January reached a settlement with environmental groups and others over the retirement of the plant, due to shut down in 2025.

## Q2 EARNINGS

# FirstEnergy CEO Says Country Heading for Natural Gas 'Disaster'

Continued from page 33

enough that FES decided it was worth pursuing."

"I think we always knew this was going to happen at some point in time," Jones said. "I think it is clearly the preferred route if we end up in a bankruptcy proceeding with FES to do it through a structured settlement that all parties are comfortable with."

FES has done some settling already. In April, the company agreed to pay $109 million to settle a legal dispute with two railroads concerning coal transportation contracts that the company said it should have been allowed to exit because it was forced by new environmental regulations to close some of the plants to which the railroads delivered. Jones said FirstEnergy is talking to one of those railroads and another one concerning a different dispute and remains "optimistic that a settlement can be reached."

FirstEnergy has tried to persuade Ohio legislators and regulators to treat its power plants as rate-base units but hasn't been successful. It also tried to get Ohio regulators to give it a subsidy of $4.46 billion over eight years, but they only gave it $612 million over three years. (See PUCO Rejects FirstEnergy's $558M Rider, OKs $132.5M.)

Even though it's getting out of competitive generation, Jones said FirstEnergy will continue to press for subsidies to allow nuclear plants in competitive generation markets to continue operating. Ohio was considering legislation that would set up a zero-emission nuclear (ZEN) resource program similar to the zero-emission credit (ZEC) programs established to funnel money to nuclear plants in New York and Illinois.

"I am going to continue to fight for this ZEN legislation because it is the right thing to do for the state of Ohio; it's the right thing to do for those assets," Jones said. "It gives those assets the best chance of running under new owners."

Jones also said FirstEnergy is looking forward to the release of the Department of Energy study of electrical markets and reliability, which, he said, "is expected to address economic and security risks associated with the premature closure of the nation's fuel-secure baseload generation as a result of regulations, subsidies and tax policies."

"We're optimistic that the final DOE study … could offer solutions to address this national concern. And the FES board is closely following this effort, which is expected to help them determine the right path forward for FES."

## SCE Profits Down

Southern California Edison's (SCE) profit fell by $11 million to $307 million in the second quarter "due to a reduction in [PUC] revenue related to prior overcollections," the company said. Year-to-date revenue was $656 million, compared with $612 million in the first six months of 2016, with some influence from rate case and operations and maintenance numbers.

Edison International CEO Pedro Pizarro said July 27 that the company has hired an adviser to study selling its SoCore Energy solar business. "We just wanted to explore whether there are other options, including the potential for a sale," he explained.

SCE's capital expenditures are trending downward from the originally forecast $4.2 billion and are currently expected to be about $3.8 billion because of delays in transmission spending, lower customer growth and lack of approval of grid modernization.

SCE is in the midst of a rate case, and in June it lowered its capital funding request by about $420 million, $300 million of which is devoted to grid modernization. The company has run into opposition to its grid modernization plan from environmental groups, which want more focus on distributed energy resources and renewables.

## Xcel Beats Expectations

Xcel Energy on Thursday reported second-quarter earnings of $227 million ($0.45/share), up from $197 million ($0.39/shar) a year ago. That beat analyst expectations gathered by Thomson Reuters of 42 cents/share. Xcel's revenue came in at $2.65 billion, ahead of $2.6 billion expectations.

The Minneapolis-based company said rate increases in Minnesota, New Mexico, Texas and Wisconsin led to higher margins. Xcel also benefited from higher natural gas profit margins, lower operations and maintenance expenses, and a lower tax rate.

*— Jason Fordney and Tom Kleckner*

# AEP to Spend $4.5B on Largest Wind Farm in US

Continued from page 1

AEP's announcement came as the American Wind Energy Association reported that wind projects under construction or advanced development rose 40% year-over-year in the second quarter. Kansas became the fifth state with more than 5,000 MW of installed wind, joining Texas, Iowa, Oklahoma and California.

The transmission segment of the project is similar in scale to Clean Line Energy's proposed Plains & Eastern Clean Line, a $2.5 billion, 700-mile HVDC transmission line that would deliver 4,000 MW of wind power from the Oklahoma Panhandle to the Tennessee Valley Authority near Memphis, Tenn.

### 'Exciting Development'

"It's a pretty exciting development for transmission," Clean Line founder and President Mike Skelly told *RTO Insider*. "We've always believed building wind in the windiest places of the country with long-distance lines to load is a great answer for ratepayers and energy overall. These guys

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# AEP to Spend $4.5B on Largest Wind Farm in US

*Continued from page 34*

believe in the same thing.

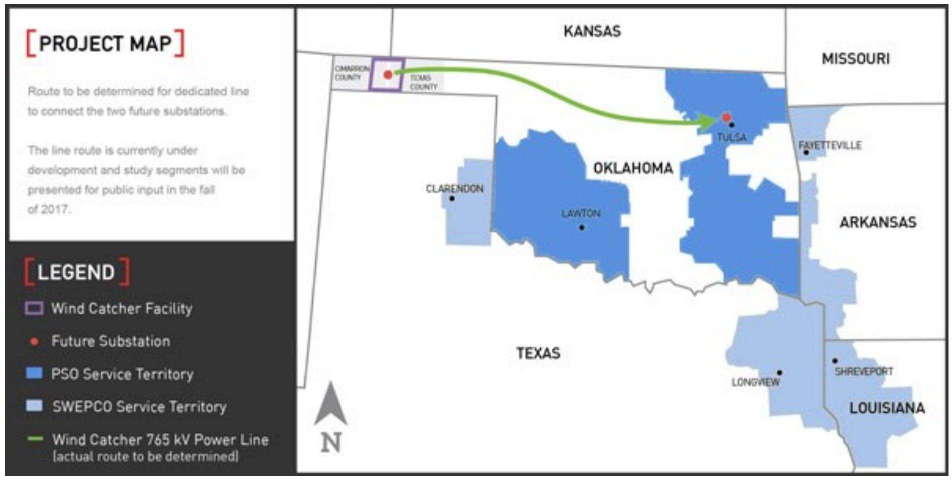
"When the biggest utility says, 'You know what? We believe that too' … that's a very positive thing for our industry. It bodes really well."

Plains & Eastern has met opposition from Arkansas legislators and landowners. Clean Line's Grain Belt Express project has run into stiff pushback in Missouri. (See Arkansas Landowners Seek to Stop Plains & Eastern Clean Line Project.)

Asked about advice he would give AEP given regulatory approvals and landowner opposition, Skelly said, "AEP is one of the biggest utilities we have. Far be it from me to offer them advice."

Akins said the project would not cause AEP to shutter any of its other generators. He said only 7% of the power coming out of the wind farm "counts as capacity, so you still need the other units to provide capacity, and they fill in from an energy perspective as well.

"We're not shutting any other units down; those units are absolutely needed. But what it does is provide more diversity from a resource perspective."




*American Electric Power*

AEP also is touting the project's effect on its service areas' economies, saying it will save ratepayers $7 billion over 25 years and support 8,400 jobs during construction. The project will support 80 permanent jobs once it's operational and contribute approximately $300 million in property taxes over its life, according to the company.

AEP said it earned $375 million ($0.76/share) on revenue of $3.6 billion in the second quarter. Its earnings, adjusted for non-recurring gains, were 75 cents/share. That was short of the average estimate of seven analysts surveyed by Zacks Investment Research, which was 82 cents/share.

# COMPANY BRIEFS

## DOE Approves Georgia Power's Vogtle Plan

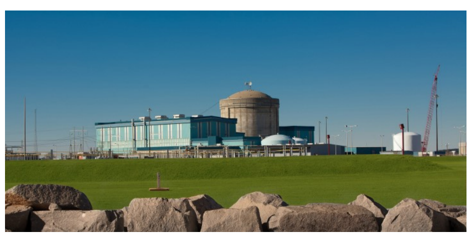
Plant Vogtle

Georgia Power said Friday that the Department of Energy has given final approval to its plan to take over management of the nuclear expansion at Plant Vogtle.

Georgia Power's Southern Nuclear affiliate will oversee construction at the site on the Savannah River south of Augusta, Ga., under a new service agreement between the company and the project's former contractor, Westinghouse Electric.

More: Atlanta Business Chronicle

## Santee Cooper, SCE&G Pull Plug on VC Summer



V.C. Summer Unit 1

Santee Cooper and SCE&G said Monday they would halt construction on the two partially completed reactors at the V.C. Summer Nuclear Generating Station.

Santee Cooper made its decision first and SCE&G, which is a subsidiary of SCANA, concluded it couldn't follow through on the project on its own.

SCE&G customers could remain on the hook for up to $9 billion already spent on the project.

More: Charlotte Business Journal

## Westinghouse Asks for Extra 3 Months to File Reorganization Plan

Westinghouse Electric asked a bankruptcy judge Wednesday to allow it an extra three months, until Dec. 6, to file a reorganization plan.

The company, which filed for Chapter 11 in March, is also seeking an extension to Feb. 4, 2018, of the 60-day period for it to try to gain approval of its reorganization plan without having to worry about competing plans.

On Thursday, Santee Cooper and SCE&G announced they will accept nearly $2.2 billion offered by Westinghouse parent Toshiba to defray costs associated with the V.C. Summer nuclear construction project, for which Westinghouse was the chief contractor.

More: Pittsburgh Post-Gazette; The State

*Continued on page 36*

# COMPANY BRIEFS

Continued from page 35

## Pope Succeeding Piro as PGE's CEO


Pope

Portland General Electric's board of directors has appointed Maria Pope — senior vice president of power, supply, operations and resource strategy — to succeed Jim Piro as president and CEO.

Piro told the board on July 26 that he would retire from the company on Dec. 31. Pope will become president on Oct. 1 and CEO and a board member on Jan. 1, 2018.

More: *Portland General Electric*

## Go Electric Wins Utah Storage Contract

Go Electric has won a $1.7 million contract to install a 1-MW advanced battery-based energy storage system at the Tooele Army Depot in Tooele, Utah.

The Anderson, Ind., company was awarded the contract by Perini Management Services. The storage system will be part of a grid-connected microgrid.

More: *Microgrid Media*

## Court Rejects SCE's Claim For $100M Tax Refund

The Nevada Supreme Court ruled Thursday that Southern California Edison is not owed a refund of about $100 million for taxes paid for coal used at its defunct Mohave Generating Station.

SCE sought the refund for use tax paid on coal purchased between 1998 and 2005, claiming the assessment on coal purchased in Arizona and then used in Nevada violated commerce laws protected under the Constitution.

The court found SCE did not pay sales tax to Arizona but rather agreed to reimburse Peabody Western Coal for the monies as part of a purchase price it paid to Peabody for coal slurry.

More: *Mohave Valley Daily News*

## JPMorgan Chase Commits to Renewable Energy

JPMorgan Chase announced Friday it will rely solely on renewable energy through 2020 and that it plans to facilitate $200 billion in clean financing through 2025.

The banking and financial services company, which has about 75 million square feet of property spread across more than 60 countries, said it will develop on-site solar-power generation at up to 1,400 retail and 40 commercial buildings. It also will install solar panels at Chase branches in California and New Jersey, large-capacity fuel-cell technology at commercial sites and small-capacity fuel cells at retail sites.

"Business must play a leadership role in creating solutions that protect the environment and grow the economy," CEO Jamie Dimon said in a statement.

More: *CNBC*

## Jackson Reasor Retiring From ODEC in January


Reasor

Jackson Reasor, president and CEO of Old Dominion Electric Cooperative, announced that he will retire on Jan. 15 after almost 20 years in his post.

Reasor, the longest-serving chief executive in ODEC history, served as a Virginia state senator from 1992 through late 1998, when he left to lead ODEC. For almost three years, he chaired the Joint Subcommittee on Electric Industry Restructuring to explore possible deregulation of the state's monopoly power companies.

ODEC's board has formed a search committee and said it will hire a national executive recruiting firm to identify a successor.

More: *Richmond Times-Dispatch*

## National Grid Seeks 53% Rate Increase

National Grid has filed a proposal with Rhode Island regulators seeking a 53% rate hike for residential customers, from 6.3 cents/kWh to 9.5 cents/kWh.

The new rate, which would go into effect for the billing period from Oct. 1 to March 31, would cause the typical customer's monthly bill to increase from $89.06 to $106.19.

Company spokesman Ted Kresse said the increase is needed because several plant retirements in New England caused the region to go from having a capacity surplus to a shortfall, driving up prices.

More: *Providence Journal*

## SunEdison Bankruptcy Plan Wins Approval; Shareholders Get Nothing

SunEdison, which filed for Chapter 11 in April 2016 with $16.1 billion in liabilities, received court approval of a bankruptcy plan last week that will leave its shareholders emptyhanded.

U.S. Bankruptcy Judge Stuart Bernstein approved the reorganization plan over the objections of shareholders, whose investment at one point was worth about $10 billion.

Almost all of SunEdison's creditors voted in favor of the plan, with about 78% of the company's unsecured creditors — who will recover about 3% of what they are owed — approving. The company is expected to formally emerge from bankruptcy by mid-November.

More: *Bloomberg Markets; St. Louis Business Journal*

## Electricity Maine Insurer Doesn't Want to Defend Lawsuit

Zurich American Insurance has sued Electricity Maine in federal court seeking a ruling that it is not obligated to defend the retailer in a class-action lawsuit brought by its customers.

In November, former Electricity Maine customers sued the company claiming thousands were lured into electricity contracts by false advertising and lost at least $35 million total.

Zurich alleges the suit does not fall within the terms of a policy Electricity Maine had from 2011 to 2012 with Assurance Company of America. Zurich eventually acquired the policy through mergers.

More: *BDN Maine*

# FEDERAL BRIEFS

## NRC Scolds TVA over Watts Bar Employee Complaints

The Nuclear Regulatory Commission announced in an order issued Thursday it would not seek civil penalties against the Tennessee Valley Authority over its mishandling of employee concerns at its Watts Bar nuclear plant.

The commission said TVA violated regulatory requirements and an earlier 2009 order by stifling or ignoring some employee comments and concerns prior to the plant's Unit 2 startup last year. However, TVA has since revamped its procedures and policies to help encourage employees to voice concerns and to prevent managers from trying to suppress such comments, the commission said.

"We were disappointed that the 2009 order had not been followed completely, but we believe this new order gives TVA a well-defined path to ensuring the existence of a safety-conscious work environment at all its nuclear sites," NRC Region II Administrator Cathy Haney said. "The ability to raise safety issues without fear of reprisal is very important to ensuring the safety of any plant."

More: *Times Free Press*

## Residential Power Sales down Since 2010

U.S. residential electricity sales have declined in both absolute and per capita terms since 2010, according to the Energy Information Administration.

Annual residential electricity sales have fallen 3% and residential electricity sales per capita have fallen 7%. Energy efficiency improvements and economic factors have contributed to the drop, the agency said.

More: *EIA*

## AWEA: 25.8 GW of Wind Projects in the Works

The U.S. wind industry installed 357 MW of capacity in the second quarter of 2017 but had a much greater 25,819 MW of projects in the works at the end of June, according to the American Wind Energy Association.

The projects underway mark a 41% rise compared with the same time in 2016. They include 14,004 MW under construction and 11,815 MW in advanced development. The total is the highest since AWEA began tracking the categories at the start of 2016.

Overall, the U.S. has 84,405 MW of installed wind capacity.

More: *Renewables Now*

## House Slashes Funding for Clean Energy, Energy Efficiency

The House of Representatives on Thursday approved a $9 billion federal energy spending plan that would slash funding for clean energy and energy efficiency programs by 45%, while maintaining support for fossil energy research and development.

Departing from President Trump, who sought a 55% cut in funding for the Office of Fossil Energy Research and Development, the House voted to keep funding at current levels but denied by voice vote nine amendments proposed by Democrats to keep clean energy funding at current levels.

Lawmakers set the Office of Energy Efficiency and Renewable Energy's budget at $1.12 billion, compared with its 2017 budget of $2.069 billion. The funding is about $500 million more than the White House sought.

More: *InsideClimate News*

## Report: 50% Increase in Renewables Needed to Meet State Standards

Renewable electricity generation will need to increase 50% by 2030 for states to meet their renewable portfolio standards, according to a new report from Lawrence Berkeley National Laboratory.

The "U.S. Renewables Portfolio Standards: 2017 Annual Status Report" found renewable standards have driven about half of all growth in U.S. renewable electricity generation and capacity since 2000 to its current level of 10% of all electricity sales. In the West, Mid-Atlantic and Northeast regions, standards drove 70 to 90% of new renewable electricity capacity additions in 2016.

The report found that nationally, the role of renewable policies in driving growth is starting to decline, as corporate contracts from companies committed to getting all their electricity from renewables increasingly take hold.

More: *InsideClimate News*

## VC Funding for Battery Storage, Smart Grid, EE Tops $1B in H1

Total global funding raised during the first half of 2017 for the battery storage, smart grid and energy efficiency sectors surpassed $1 billion, a 25% increase compared with the same time last year, according to a new report by Mercom Capital Group.

According to the global clean energy communications and consulting firm, the battery storage sector saw the top venture capital deal of $400 million. Venture capital funding for the sector reached $480 million across 18 deals in the first half of the year, compared with $179 million raised over 20 deals a year ago.

Venture capital funding for smart grid companies reached $304 million, while funding for the energy efficiency sector reached $242 million.

More: *Clean Technica*

## Report: Solar Panel Tariffs Could Erase Industry Growth

Suniva's petition before the U.S. International Trade Commission to impose tariffs on imported solar panels could wipe out two-thirds of solar facilities forecast to be installed over the next five years, according to a report by GTM Research.

If Suniva prevails, equipment prices would spike in the U.S. and trigger a fall in installations to as low as 25 GW from 2018 to 2022, down from GTM's current forecast of 72.5 GW, GTM said.

The report found large-scale "unity" solar farms would take the biggest hit from the tariffs, with residential rooftop installations less likely to be impacted.

More: *Bloomberg Markets*

# STATE BRIEFS

## CALIFORNIA

### CCA Program Gains 11 New Communities

Eleven new communities have voted to enroll in a community choice aggregation program that offers 100% renewable energy for an additional penny per kilowatt-hour.

Over a three-month period, the cities and towns of Corte Madera, El Cerrito, Larkspur, Mill Valley, Napa, Novato, Richmond, Ross and San Rafael, as well as the counties of Marin and Napa, joined Belvedere, Fairfax, San Anselmo, San Pablo and Sausalito in opting for Marin Clean Energy's "Deep Green" option.

Marin, which set up shop in 2010 as the state's first CCA, estimates that consumption of 100% renewables will increase by 66% this year. By 2018, it expects to hit its goal of Deep Green making up 5% of its total electricity load, seven years ahead of its 2025 target.

More: *pv magazine*

## MICHIGAN

### Sens. Ask FERC to Halt Pipeline Near Kids' Camp

U.S. Sens. Debbie Stabenow and Gary Peters are asking FERC to pause construction on a natural gas pipeline they say could endanger kids at a YMCA camp and residents of nearly 100 homes in the event of an explosion.

Energy Transfer's 42-inch Rover pipeline would pass through Livingston, Washtenaw and Lenawee counties before linking up with an existing Vector pipeline south of Fowlerville that is a joint venture between Enbridge and DTE Energy. At issue is a segment around Silver Lake near Pinckney in Dexter Township that will run less than 300 feet from a YMCA campground for children, according to a letter the senators sent to FERC.

The pipeline route, which was originally supposed to follow an existing ITC Holdings transmission line corridor, changed during FERC's review. The senators' letter suggests the route change happened in a confusing manner, and the public was not afforded adequate opportunity to submit public comments on the final route.

More: *Livingston Daily*

## NEW HAMPSIRE

### Regulators Temporarily Shut Down Renewables Rebate Programs

The Public Utilities Commission recently announced the closure until at least Sept. 1 of the state's Residential Solar and Wind Rebate program and the Commercial and Industrial Solar Rebate program because of fiscal year 2018 budget constraints and an influx of waitlisted applications.

According to a notice from Debra A. Howland, executive director of the PUC, the two programs are experiencing record demand and have application waitlists for rebates totaling about $1 million and $500,000, respectively.

The commission said it may also consider changes to the terms and conditions of the two programs prior to their reopening. Under the Residential Solar and Wind Rebate program, homeowners who install solar photovoltaic systems or wind turbines under 10 kW can receive a rebate of 50 cents/W (up to $2,500) or 30% of the total project cost. The Commercial and Industrial Solar Incentive Program offers two rebate categories — one for solar thermal or photovoltaic systems under 100 kW and one for photovoltaic systems between 100 and 500 kW.

More: *North American Wind Power; Public Utilities Commission*

## NORTH CAROLINA

### Cooper Signs Solar Bill Despite 'Ugly' Wind Moratorium

Gov. Roy Cooper on Thursday signed into law legislation promoting solar energy and placing an 18-month moratorium on wind power projects, while also signing an executive order encouraging wind power development in the state.

The moratorium was pushed by Senate Majority Leader Harry Brown (R), who said he is concerned that wind towers could interfere with the state's military installations. Cooper said the executive order clarifies that wind projects can proceed through the initial permit stages and that the state should do all it can to help bring them to fruition, regardless of the temporary ban.

House Bill 589 contained multiple provisions advancing solar energy, including a provision allowing people to lease rooftop solar panels, rather than having to purchase them outright. Cooper said he strongly opposed the "ugly, last-minute, politically motivated wind moratorium," but that he did not want to lose the solar deal.

More: *The News & Observer*

## OHIO

### Senator Plans Legislation Amending Wind Turbine Setback

State Sen. Cliff Hite plans to introduce legislation this fall that amends how far wind turbines must be set back from adjacent properties.

Hite in June proposed new language for the budget bill that would have based the setback difference on turbines' height and blade length, but the language disappeared in final House and Senate negotiations.

Sen. Matt Dolan, who said he would cosponsor the bill, thinks the setback issue, along with years of arguing about the state's renewable energy mandates, has made the state unattractive to renewable energy developers.

More: *The Plain Dealer*

## VERMONT

### PUC Rejects Solar Array, Finding It Would Detract from Mountain View

The Public Utility Commission denied approval of a 145-kW solar array, finding it would detract from the view from Mount Philo, in Charlotte.

The project, proposed by Peck Electric, would have consisted of 650 ground-mounted solar panels, each 9 feet tall, arranged in rows of seven. It would have been positioned off Route 7, less than a mile from the mountain, with a stand of trees intended to shield it.

Jeff Peck, president of Peck Electric, said the array would not have detracted from the view. "I believe a small-scale clean energy project would have complemented the vista and serve as a small visual representation of the value that Vermonters place on buying locally produced clean energy," he said.

More: *VT Digger*

# RTOs to Congress: Don't Lose Faith in Markets

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From left to right: Gordon van Welie, ISO-NE; Nick Brown, SPP; Brad Jones, NYISO; Richard Doying, MISO; Cheryl Mele, ERCOT; Keith Casey, CAISO; and Craig Glazer, PJM. | © RTO Insider

Doying.

Representatives from all six FERC-regulated RTOs and ISOs appeared along with an ERCOT executive at the nearly two-and-a-half hour hearing, the third in a series of fact-finding sessions that began last year with a letter to FERC and a hearing in September on the 1935 Federal Power Act. On July 18, the committee heard from stakeholders representing public power, independent power producers and integrated utilities. (See *Public Power Takes PJM Gripes to Congress*.)

A Republican committee aide, speaking on background, said the bipartisan hearings will resume after the August recess. Although some witnesses and committee members at last week's hearing called for changes to the 1978 Public Utility Regulatory Policies Act, "consistently what we've heard is that there's no immediate need" for changes in the FPA, the aide said.

The aide said, however, that the May 1-2 FERC technical conference on tensions between wholesale markets and out-of-market procurements and subsidies "got more attention [from House members] than any other technical conference in recent history."

### Criticism Nothing New

As at the technical conference and the July 18 House hearing, much of the focus was on PJM, NYISO and ISO-NE, the three eastern grid operators facing the most acute challenges from state policies.

PJM has perhaps the toughest challenge of the three grids in threading the needle between stakeholders pushing for supports for coal and nuclear "baseload" power and efforts to insulate the markets from price suppression. Unlike the single-state NYISO and the environmentally activist New England states, PJM's footprint is particularly diverse, encompassing both consumer choice states and traditional, vertically integrated states; only some states have renewable portfolio standards; some states are coal producers, while others are heavily reliant on nuclear power.

But Glazer, a former Ohio utility regulator and PJM's longtime voice in D.C., said the conflicts are nothing new for the RTO.

"The PJM markets have weathered many challenges to the industry, ranging from the impact of EPA's Mercury and Air Toxics rule on the coal fleet to the threats of cyberattacks on the grid itself," he testified. "We are stronger as a result and are confident that innovative market-based solutions, which have been the hallmark of PJM since its inception, can continue to serve us well in addressing our new set of 21st century challenges."

He appealed to his congressional inquisitors by holding up photos of new generation in several of the committee members' districts.

On several occasions, he attempted to rebut criticism by public power providers who say their self-supply option has been eroded since the settlement that created PJM's capacity construct. Lisa McAlister, senior vice president and general counsel of regulatory affairs for American Municipal Power, told the committee July 18 that PJM rule changes "have stripped away guaranteed clearing for self-supply."

Glazer cited 1,375 MW of new generation or uprates to existing public power-owned generation since the inception of the capacity market. The RTO has added more than 46.5 GW of new generation over the same period.

He said confusion may have resulted from the July 7 D.C. Circuit Court of Appeals overturning portions of PJM's minimum offer price rule. (See *PJM MOPR Order Reversed; FERC Overstepped, Court Says*.)

The order "did not overturn the specific agreed-to arrangement that PJM and its stakeholders worked out with public power entities," Glazer said. "As a result, the right to self-supply in our capacity market and energy market has been negotiated with public power and fully honored by PJM and its stakeholders. To suggest otherwise is simply not consistent with those facts."

"Absolutely, we have self-supply today," Glazer reiterated in response to a question from Rep. John Shimkus (R-Ill.). "We have no intention of changing that."

But Glazer rejected public power's call to abandon the capacity market and use bilateral contracts to fill most of its capacity needs, saying it would eliminate price transparency.

Griffith

Glazer had an exchange with Rep. Morgan Griffith (R-Va.), who complained that coal-fired generation was "under severe assault." Glazer said PJM's proposal that FERC change its price formation rules "to better recognize the attributes that key generators — including those which have come to be labeled 'baseload generation' — bring to the grid" would provide financial help for struggling coal plants. He said the proposed changes would "ensure that all resources needed to serve load are able to set wholesale prices."

But he rejected Griffith's claim that stranded costs resulting from premature coal plant retirements were falling on ratepayers. "We moved to the markets to try to not put it all on the backs of the customer," he said.

Ranking member Frank Pallone (D-N.J.) took PJM to task for what he called exces-

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# RTOs to Congress: Don't Lose Faith in Markets

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sive transmission spending and a lack of transparency in the RTO's Regional Transmission Expansion Plan. Glazer noted that the Transmission Expansion Advisory Committee meetings are open to the public and sought to distinguish PJM's role from that of state siting authorities. "Maybe we need to do more to reach out," he offered.

### ISO-NE

ISO-NE CEO Gordon van Welie recalled his testimony before the committee in March 2013, when he cited the "serious operational challenges" facing New England because of its changing generation mix.

van Welie

"As New England has increased its reliance on natural gas [since 2013], we have not seen a corresponding increase in the region's natural gas transportation and storage infrastructure, which is currently stressed to meet demand for natural gas for both home heating and power generation during the coldest weeks of the year," he said. "The shift from power plants with on-site fuel supply (e.g., oil, coal and nuclear) to plants relying on the natural gas transportation network to deliver fuel when needed has exposed the limitations of New England's fuel infrastructure system and highlights the challenge of securing fuel in advance of power system demands."

Van Welie said the RTO has concluded that the Pay-for-Performance capacity incentives developed in 2013 "may not be sufficient to ensure fuel security during the winter" because of opposition to siting dual-fuel facilities and tighter emission limits that restrict the amount of time generators can operate on oil. That, he said "is likely to create greater dependency" on LNG imports.

### NYISO

NYISO CEO Brad Jones briefed members on the ISO's proposed transmission expansions to connect upstate renewables to downstate loads and its plan to incorporate carbon prices in its energy market — a response to the zero-emission credits approved for three upstate nuclear plants. (See New York ZEC Suit Dismissed.)

Jones

The ISO said it expects to release The Brattle Group's report on the carbon plan within two weeks. That, Jones said, will be the basis for discussions with market participants and state officials. He said the ISO hopes to implement the plan in the markets within three years.

### ERCOT

Unlike the other grid operators, ERCOT is still seeing strong load growth, said Chief Operating Officer Cheryl Mele. After growing at 2% annually in recent years, ERCOT expects annual growth of 1.5% for the next five years.

Mele

One thing it does have in common with the other regions: Low energy prices are pinching the finances of thermal and nuclear units. "We also have seen that, for several years, investors and unit owners of every type of generation were watching to see if there would be federal environmental policies that would materially affect their investments or retirement strategies," Mele said. "That conversation has since changed. Nevertheless, aside from regulatory concerns, ongoing changes in the generation resource mix and market dynamics may have major impacts on potential unit retirement decisions."

### CAISO

Keith Casey, CAISO's vice president of market and infrastructure development, told the committee the effects of low power prices — which have sparked calls for nuclear and coal subsidies in the eastern markets — also have led "conventional" plants in California to request "backstop" contracts to maintain their financial viability. (See CAISO Stakeholders Question Risk-of-Retirement Initiative.)

Casey

Casey, too, defended the markets. "We have almost 20 years of operating experience and have evolved our markets since the Western Energy Crisis occurred 17 years ago," he said. "Consequently, the California ISO's electricity markets have matured significantly and are in far better shape now than they were then to serve electric demand in an efficient and reliable manner. Indeed, our success has encouraged other transmission providers in the West to join our real-time energy market and form the Western Energy Imbalance Market."