RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ■ ERCOT ■ ISO-NE ■ MISO ■ NYISO ■ PJM ■ SPP

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Judge Rejects Liability Release in FirstEnergy Reorg

By John Funk

AKRON, Ohio — A U.S. bankruptcy judge signaled Thursday he will not confirm a reorganization plan for FirstEnergy Solutions that would have absolved its parent company from liability for environmental damages from its coal and nuclear power plants.

Bankruptcy Judge Alan Koschik of the Northern District of Ohio ruled orally from the bench that the "disclosure statement" FES must send to creditors describes a reorganization plan the court would find "patently unconfirmable."

In other words, the judge has — at least for now — ruled the reorganization plan as proposed will not be confirmed.

FES said late Thursday it will submit a revised disclosure statement.

"Working with our advisers, we have already initiated action to address the court's ruling and will submit a new request to have the disclosure statement approved in a timely manner," FES CEO John Judge said. "The company remains focused on a plan that will significantly strengthen its financial position and allow it to exit Chapter 11 in 2019."

Koschik said the restructuring plan giving broad protection to parent FirstEnergy Corp. does not meet case law established by the 6th U.S. Circuit Court of Appeals.

Environmental groups, including the Sierra Club and a coalition led by the Chicago-based Environmental Law and Policy Center, had challenged the attempt to limit FirstEnergy's environmental liability for months. The Ohio Consumers' Counsel had also weighed in.

"Judge Koschik correctly determined that debtor FirstEnergy Solutions' extraordinarily broad releases of environmental liabilities and responsibilities make the proposed reorganization plan 'patently unconfirmable,'" wrote ELPC Executive Director Howard Learner in a

Continued on page 25

FERC Asks RTOs for more Details on Storage Rules

By RTO Insider Staff

FERC staff last week issued deficiency letters to all six jurisdictional RTOs and ISOs over their proposed energy storage rules, pressing for definitions, tariff citations and details on issues including metering, make-whole payments, and self-scheduling.

The grid operators are facing a December deadline for compliance with Order 841, which requires them to revise their market participation models to allow storage resources 100 kW and larger to provide capacity, energy and ancillary services within their technical ability.

The deficiency letters by the Division of Electric Power Regulation ranged from eight to 11 pages.

Jeff Dennis, general counsel of Advanced Energy Economy, said in a tweet that the detailed questions "demonstrate that FERC is looking for real compliance with the [requirements] to open the markets to storage, and not just paper compliance. Overall, I think this is a positive development."

"They have some hard questions that go to the particular issues raised by commenters," agreed Earthjustice attorney Kim Smaczniak.

Below is a summary of the issues raised by staff. The grid operators have 30 days to respond.

FERC Challenges CAISO on Storage Minimum

California ISO

FERC cited seven major areas of concern regarding CAISO's proposal (*ER19-468*).

Staff wanted the ISO to explain, for instance,

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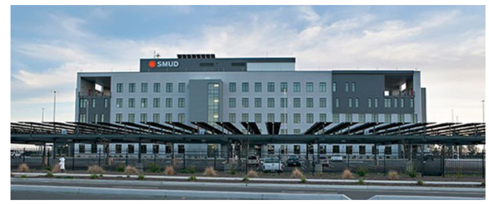
SMUD Goes Live in Western EIM

By Hudson Sangree



Sacramento Municipal Utility District headquarters | *SMUD*

The Western Energy Imbalance Market continued expanding Wednesday as the Sacramento Municipal Utility District (SMUD) became the first publicly owned utility to begin participating in CAISO's real-time electricity market for the West.

"The Western EIM demonstrates the economic and environmental savings achieved when participants work collaboratively across the region," CAISO CEO Steve Berberich said in a news release. "As one of the premiere community-owned utilities in the country, SMUD's participation will only strengthen the market and add to its efficiency and diversity."

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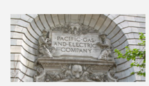

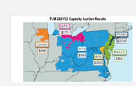

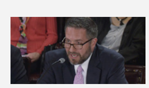

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In this week's issue

ERO INSIDER

This is a preview of ERO Insider, a new publication providing exclusive coverage of NERC and the Regional Entities that form the Electric Reliability Organization. Pricing and other details will be coming later this spring. For now, email any feedback on our coverage to EROInsider@RTOInsider.com.

Transmission Resiliency Summit Focuses on Grid Security

More than 200 representatives from utilities, RTOs, NERC regional entities and government agencies gathered at EPRI's lab in Charlotte, N.C. | *© RTO Insider*

By Michael Brooks

CHARLOTTE, N.C. — There was no stated theme to this year's Transmission Resiliency Summit, held at Electric Power Research Institute laboratories last week, but some common motifs ran through the event.

The North American Transmission Forum (NATF), headquartered less than 6 miles west of the EPRI labs, gathered representatives from utilities, RTOs, NERC regional entities and government agencies to discuss improving the resilience of the bulk electric system.

Tom Galloway | *© RTO Insider*

That group held its first meeting in April 2013 in the aftermath of Superstorm Sandy, focusing on severe weather events, according to NATF CEO Tom Galloway. Less than two weeks later, gunmen carried out a highly sophisticated attack on Pacific Gas and Electric's Metcalf substation, costing the utility more than $15 million in direct costs and $100 million in security upgrades.

Galloway's recollection of those events set the stage for two days of discussing not just the myriad threats the grid faces — and the best ways to secure the grid, both physically and digitally, against them — but also how to respond to and recover from a catastrophic event.

Andrew Phillips | *© RTO Insider*

Last week's summit, hosted jointly with NERC this year, was the largest NATF and EPRI have held and the first one open to non-NATF members, including the press. Andrew Phillips, EPRI vice president of transmission and distribution infrastructure, said 230 people had registered, representing more than 100 different entities from the U.S. and Canada.

The maximum capacity for the conference room: 230. And there were only a few open seats throughout the event.

"Who's who in the zoo [are] all here," said Brian Harrell, assistant director for infrastructure security at the Department of Homeland Security's Cybersecurity and Infrastructure Security Agency (CISA). "No. 1, I think that's a testament to this particular conference, and two, it's showcasing the fact that you all are taking resilience very, very seriously."

Brian Harrell | *© RTO Insider*

Speakers Stress Collaboration, Info Sharing

A constant refrain among the multiple speeches, presentations and panels was an emphasis on working together and sharing information, both between the public and private sectors, and among utilities.

"I think we really need to advocate for a collective defense: Whether you are a critical infrastructure company, whether you are a citizen of the United States or you are the U.S. government, we are all in this together," said Harrell, a former director of the Electricity Information Sharing and Analysis Center (E-ISAC). "Your problem quickly becomes my problem. My problem quickly becomes your problem. Duke's problem quickly becomes SCANA's problem, which becomes Dominion's problem, etc."

The current director of E-ISAC, Bill Lawrence, urged attendees to join the NERC-operated program, noting the effort to improve its web-based tools in the past few years. "Basically, back in 2015, many of your organizations took a hard look at us and said, 'Hey, ISAC, if [you want us] to use you, you gotta suck less.'"

Bill Lawrence | *© RTO Insider*

E-ISAC benefits from the required reporting under NERC's Critical Infrastructure Protection standards, "but we also need to get that voluntary information sharing," Lawrence said in a presentation on measuring the program's effectiveness. "We're definitely not sitting on ... a pile of gold in voluntary shares, but it's growing, because our vision is to be a world-class, trusted source of quality analysis and rapid sharing of electric infrastructure security information."

Galloway asked Lawrence if there was anything besides "'better information sharing' ... that this audience can do to better support you in moving the E-ISAC forward."

"Other than my catch-all — 'share more' — challenge us," Lawrence answered. He encouraged members to inform the center if they found its resources were not useful to them.

Most of the first day of the event was spent discussing the incident command system (ICS). The concept was originally developed by fire chiefs in several states in the 1970s to provide a common hierarchy and standardized terms among their departments to coordinate their

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response to wildfires. Now it is used across multiple sectors, companies and institutions to coordinate their responses to emergencies.


Wike Graham | © *RTO Insider*

"Firefighting is a team sport," said Wike Graham, battalion chief for the Charlotte Fire Department. He recalled that Carolina Panthers Head Coach Ron Rivera, after observing firefighters put out a fire in his house, compared the incident commander to a coach. "'They send the plays in, and you watch these guys, they all know what they're doing and they're working as a team.' That's what ICS is all about."

An ICS determines who is in charge (the incident commander) among teams from different entities that respond to an emergency — for example, local police, FBI and the military.


Taylor Cox | © *RTO Insider*

"Training military guys to not be in charge is difficult," said Taylor Cox, senior consultant for business continuity at Xcel Energy. "'Yes, sir, I understand you were in charge in Iraq. You are not in charge here,'" recalled Cox, a former member of the Army National Guard.

Staff members from several utilities shared their experiences implementing ICS. Manny Cancel, Consolidated Edison's chief information officer, described how his company used the system to restore power to Wall Street after the terrorist attacks of Sept. 11, 2001. Kathy Bosse, crisis manager for Exelon, said her company used the system during the civil unrest in Baltimore following the death of Freddie Gray in 2015. Others shared their experiences using the system to respond to simulated cybersecurity attacks.

Emergency Communications

The Metcalf attackers, whose motives and identities remain a mystery, cut fiber optic cables less than a mile from the substation, briefly knocking out internet, phone and 911 service in the area. "One of the things that was most troubling is that it was a very deliberate effort to impact communications," Galloway said.

One panel at the conference focused exclusively on communications during an event in which all other methods are unavailable.


Ross Merlin | © *RTO Insider*

Ross Merlin of DHS gave a presentation on the department's SHAred RESources (*SHARES*) high-frequency radio (HFR) program. He began by explaining how HFR works.

"It works by something called 'PFM.' It stands for 'pure freaking magic.'"

Actually, it's quite simple but, based on the audience's reaction to the technology, no less impressive. HFR works by bouncing signals off Earth's *ionosphere*, the part of the atmosphere that has been ionized by solar radiation, about 80 km above the surface.

Normally, HFR is used for communicating over very long distances. But it can also be used in cases where all short-distance comms are down.

"By using the right antenna, you can make your signal go almost straight up, which sounds useless unless you're trying to talk to the International Space Station," Merlin said. But once it bounces off the ionosphere, the signal comes "not just straight down, but kind of like an upside-down ice cream cone," allowing for communication within a certain radius. Users can send not only voice, but email and images as well.

SHARES has more than 2,600 participants using about 2,300 radio stations, according to Merlin. The program used to be restricted to the federal government only, but "a few years ago we found giant loophole, I mean, we found a way to reinterpret the rules so as to allow state and local government and critical infrastructure and key resources folks to take advantage of this. ... The folks you depend on, whatever you have a dependency on to keep going, we can probably get them in here."

Several attendees representing Canadian utilities said after Merlin's presentation that they intended to inquire about applying for the program.

Drones

The second day of the conference featured presentations on the threats posed by unmanned aerial vehicles, more commonly known as drones, both those used by utilities for maintenance and those used by the public — or hostile foreign actors.

CISA's Harrell repeated his warnings against using foreign-manufactured drones from last month's NERC Reliability Leadership Summit. (See *Feds Late to Act on Drone Threat, DHS Official Says*.) E-ISAC's Lawrence advised the audience to "look beyond" the manufacturers from which the federal government is banned from purchasing under the National Defense Authorization Act for Fiscal Year 2019.

There have also been incidences overseas of environmentalists using drones to try to disable electric infrastructure, including *one* last year in which Greenpeace flew a device shaped like Superman into a nuclear plant in France.

But according to Xcel's Cox, "nuisance drones," piloted by careless or curious hobbyists, are the most common threat to utilities.

"A lot of them are like the kid who throws the Frisbee on your roof and just wants his Frisbee back."

The Federal Aviation Administration has exclusive jurisdiction over what can fly where, meaning utilities that spot drones over their substations or other facilities can't do much about them except report them. But that doesn't mean utilities shouldn't monitor them.

"There are a lot of physical security managers not paying attention because they say, 'Well we can't shoot them down anyway, so why should we care?'" Cox said in response to an audience question about what is allowed. "Well a lot of your security folks don't have arrest authority, and yet we're still taking pictures of people stealing copper."

He advised utilities to leave downed drones alone: Blades can easily cut off fingers, and any sim cards could be compromised with malware.


Travis Moran | © *RTO Insider*

Travis Moran of Welund North America urged audience members to submit comments on FAA's *Advance Notice of Proposed Rulemaking* regarding drones, due April 15. Proposed earlier this month under Section 2209 of the *FAA Extension, Safety and Security Act of 2016*, the rules would allow utilities to apply for airspace restrictions over their facilities.

"2209 is your best interest right now, and you've got to get your lobby people off their butts on this," said Moran, also a strategic partner with SRC/Gryphon Sensors and a member of the Energy Drone Coalition's advisory board. "I've always said you guys get it because you're already used to the CIP standards and CIP process, so electricity should be the one to lead this. ... Get your people on there ... or else you know how the government is going to do it. They're doing it without your comment, and you're not going to like what you get." ■

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Study: Frequency Response OK in Eastern Interconnection

NERC Team Solicits Comment on Data Source

By Rich Heidorn Jr.

ATLANTA — Despite the ongoing shift to renewables, the Eastern Interconnection has sufficient inertia to maintain system frequency for at least the next five years, according to a study released Thursday.

The Eastern Interconnection Planning Collaborative (EIPC), a group of 20 planning coordinators, conducted the study in response to a request by NERC's Essential Reliability Services Working Group.

The working group had cited concerns about the retirements of synchronous generators such as coal and nuclear, which respond automatically to a frequency reduction by slowing down and releasing more energy into the grid. Asynchronous wind and solar power generators do not respond in the same way unless their inverters have been programmed to provide frequency control.

The EIPC's study was released as a NERC standards development team (SDT) reviewing other aspects of frequency response issued a request for comment on continuing to rely on FERC Form 714 for data. (See "Comments Sought" below.)

Steven Judd, lead engineer in system planning for ISO-NE and chair of the EIPC Frequency Response Task Force, said the study provided reassurance in the near term and a foundation for future projects.

"This first effort to track the interconnection's inertial response has established a framework and baseline for system planners to improve the system network models going forward, provide sufficient notice when the changing resource mix could have an adverse effect on frequency response and develop solutions to those adverse effects," Judd said.

In order to prepare for the expected increase in nonsynchronous generation with reduced inertia, the *report* said planners will need improved frequency responsive power flow simulation models.

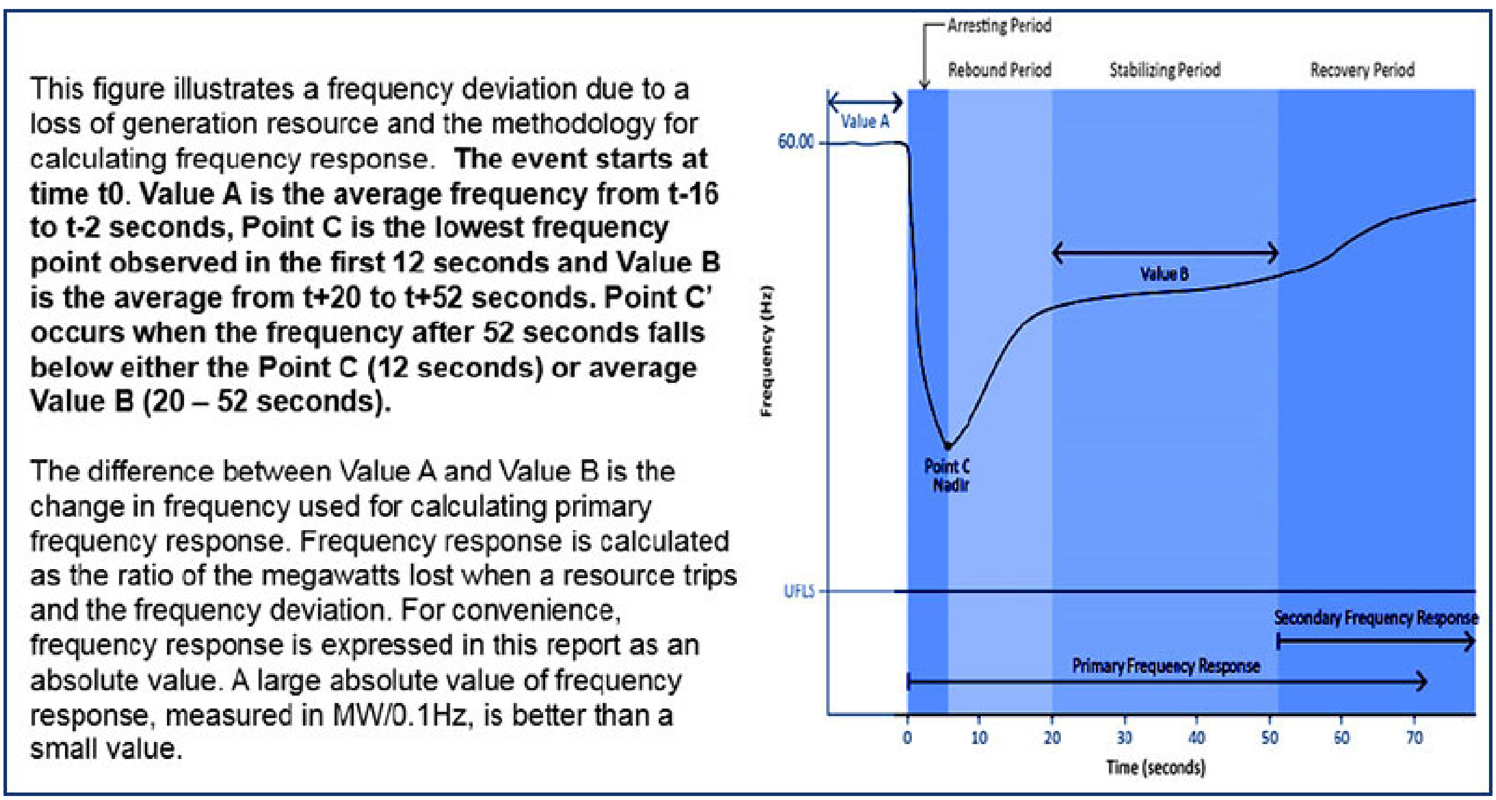
The report was based on several analyses, including benchmarking a historical frequency event with spring light load (SLL) cases, and concluded that about 45% of governors were providing primary frequency response, substantially higher than previous NERC studies, which pegged response at about 30%. Thus, for forward-looking frequency measures, 55% of the governors were disabled in the power flow model.

"It is expected future improvements to the modeling of governors through new compliance standards and updated simulation models from the software vendors will reduce the need for artificially disabling governor models to match historical performance," the task force said.

FERC Order 842, issued in February 2018, requires all new generators seeking interconnections be equipped to provide primary frequency response. (See *FERC Finalizes Frequency Response Requirement*.)

The EIPC task force tested three frequency events against the 2022 SLL Multiregional Modeling Working Group (MMWG) power flow case:

- The loss of 4,500 MW of generation in 2007,



This figure Illustrates a frequency deviation due to a loss of generation and the methodology for calculating frequency response. Value A is the average frequency from t-16 to t-2 seconds. Point C is the lowest frequency observed in the first 12 seconds and Value B is the average from t+20 to t+52 seconds. The black line represents the point at which underfrequency load shed (UFLS) is expected to occur. | *Eastern Interconnection Planning Collaborative*

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the largest historical event seen on the Easter Interconnection;

- The loss of 3,100 MW on April 27, 2011, the largest event within the past 10 years; and
- The loss of 2,513.7 MW, the most severe single contingency for the Eastern Interconnection as defined by NERC standard BAL-002-2(i) Requirement R2.2.

In all three events, frequency response fell no lower than 59.85 Hz, well above the 59.5-Hz initial set point that would trigger under frequency load shedding (UFLS).

Under a fourth benchmark — a 10,000-MW loss modeled to determine the margin available in the Eastern Interconnection — the frequency dropped to a low of 59.64 Hz, still above the UFLS set point.

"In other words, the system inertia and primary frequency response will be sufficient even with expected retirements of synchronous generation and increases in nonsynchronous generation," the report said.

The results of the analysis were submitted to NERC for inclusion in its 2018 long-term reliability assessment.

Comments Sought

On a related issue, the SDT for *Project 2017-01* (Modifications to BAL-003-1.1) on Thursday issued a request for comments following a three-day meeting last week in Atlanta.

Phase II of the project is considering potential changes to make the interconnection frequency response obligation (IFRO) calculations and associated allocations more reflective of current conditions, considering load response and the generation mix.

The standard authorization request also requires the team to ensure that overperformance by one entity does not negatively impact the evaluation of performance by another and that measurements of primary frequency response are considered in addition to secondary frequency response.


Daniel Baker (left), SPP, and Rich Hydzik, Avista | © *RTO Insider*

"I think we've got a fairly balanced industry [view]" on the standard, said SDT Chair David Lemmons, of EthosEnergy. "Some people think things need to change. Some people are happy with where it is."

The SDT *asked* commenters to address the fact that load and generation data from Form 714 is two years old by the time it is applied to actual operations under the standard. In the interim, balancing authority (BA) footprints can change.

Rich Hydzik of Avista said Form 714 was adequate for use under the standard and expressed concern that more current data might be "less robust."

"I don't think we want perfection to be the enemy of good here," he said. "What we're looking for is a fair allocation on the interconnection and the BAs."

Greg Park of Northwest Power Pool and SPP's Daniel Baker noted Form 714 also does not include data from Mexico or Canada.

"I think [714] does an adequate job … 99% adequate," Park said. "But that 1% is administratively burdensome."

Hydzik suggested later the data source could be dictated by the "fundamental question" of whether it is generators alone that are responsible for meeting the frequency response requirement (FRR). He noted load reductions don't provide much frequency response "unless generally you're paying for load to drop."

Including load strengthens the case for retaining Form 714, which includes load and generation data, he said.

"If you're going to make the leap that energy-producing resources actually provide your FRR … then we kind of move into the situation where we look at generation-only numbers and … allocate that way. It starts to look a little bit like [Texas Reliability Entity] at that point. … They have shown us what it looks like to go with the generation approach." ■

FERC & Federal News

FERC Asks RTOs for more Details on Storage Rules

Continued from page 1

how it could reconcile the difference between its own minimum size requirement for storage resources of 500 kW, as noted in a Tariff appendix, with Order 841's minimum size of 100 kW.

The commission also asked the ISO to explain if "it is CAISO's position that each of the three participation models — the non-generator resources (NGRs) model, pumped storage hydro units model and demand response model — considered on its own, complies with all of the requirements of Order No. 841."

FERC then asked the ISO to explain its eligibility requirements for storage resources to provide "all other services the CAISO procures on behalf of its market, including CAISO's backstop capacity procurement mechanism." And it requested CAISO elaborate on how it allows storage resources to derate their capacity

| SDG&E

Staff wanted CAISO to explain, for instance, how it could reconcile the difference between its own minimum size requirement for storage resources of 500 kW, as noted in a Tariff appendix, with Order 841's minimum size of 100 kW.

to meet minimum run-time requirements.

Next, FERC asked CAISO to for an explanation of how "NGRs can be dispatched as supply or demand, set marginal price, self-schedule and otherwise participate fully in CAISO's markets … [and] that pumped storage hydro resources can be dispatched as supply and demand, set wholesale market clearing prices, and submit bids and self-schedules."

It asked the ISO to further describe its mechanisms for dealing with conflicting dispatch signals and for incorporating bidding parameters.

Then it ordered CAISO to cite Tariff provisions that ensure storage resources are charged the LMP for electricity stored for "later resale back to the market" and that the resources' "charging is accounted for as negative generation" as required by Order 841.

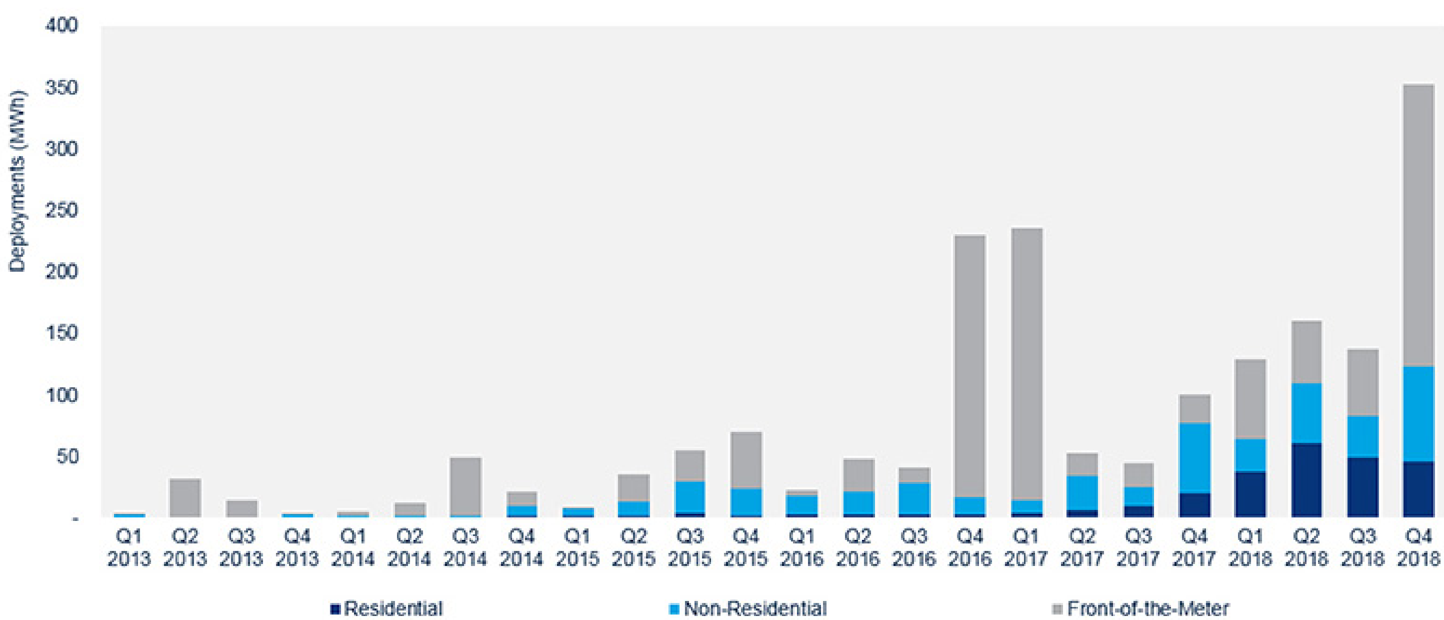
Metering and accounting practices for charging energy rounded out the commission's concerns.

"Please explain and provide citations to the relevant proposed Tariff language that demonstrates whether the NGR and pumped-hydro storage participation models prevent electric storage resources from paying both the wholesale and retail rates for the same charging energy," it wrote.

— Hudson Sangree

Questions to ISO-NE Touch on Reserves

When FERC in February accepted ISO-NE rule changes broadening energy storage resources' ability to provide capacity, energy and ancillary services, effective April 1, the commission said it would deal with the Energy Storage Association's complaints regarding how the RTO plans to assign reserves to storage when it responded to the RTO's Order



U.S. energy storage deployments by segment | *Wood Mackenzie U.S. Energy Storage Monitor 2018 Year in Review*

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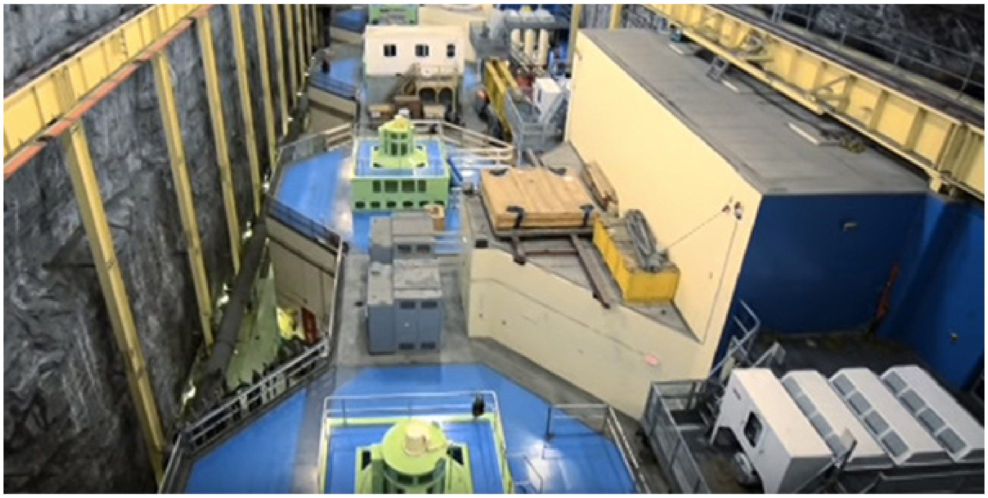


FirstLight Power Resources owns the largest pumped-storage hydroelectric plant in New England, the 1,143-MW Northfield Mountain Project on the Connecticut River in Massachusetts. | *FirstLight Power Resources*

841 compliance filing. (See *FERC Accepts ISO-NE Storage Tariff Revisions*.)

The commission's deficiency letter (*ER19-470*) asked the RTO to explain whether a continuous storage facility, if dispatched for reserves rather than energy and as a result experiences lost opportunity costs, would be compensated for its lost opportunity costs.

In addition, FERC asked the RTO to explain its "modified mechanism to permit electric storage resources with one hour or less of energy to provide only energy and not reserves," and also how the RTO "will implement such mechanism prior to Dec. 3, 2019, the effective date of ISO-NE's compliance filing."

Regarding the physical and operational characteristics, the commission questioned the RTO's use of the term "maximum discharge time," saying it "is not a characteristic defined by the commission or defined by ISO-NE." FERC asked the RTO to either define the term or "confirm that ISO-NE intended this to be written as maximum run time, as defined by Order No. 841."

The commission also asked whether some continuous storage facilities may have start-up or no-load costs, such as costs for cooling a storage facility that is online but not dispatched. "Could such costs be accounted for through non-zero values in the start-up or no-load cost parameters, similar to other resources that participate in ISO-NE markets?"

The RTO was also asked "to provide specific citations to the relevant existing and/or proposed Tariff sections that demonstrate that binary storage facilities and continuous storage facilities will not receive conflicting dispatch signals to charge and discharge simultaneously."

— Michael Kuser

Staff Seeks Details on MISO Phased Participation

In an April 1 letter requesting more information on the plan, FERC said it could not process MISO's Order 841 compliance filing until it clarifies several points regarding its phased participation approach, proposed commitment statuses, complexities for storage resources on the distribution system, conflicting offers and bids, and make-whole payments (*ER19-465*). MISO has 30 days to respond.

MISO and its stakeholders spent the better part of last year negotiating rules that culminated in a 1,300-page *filing*. (See *MISO Offers Storage Proposal, Promises to Exceed Order 841*.) The RTO said it "anticipates significant uncertainty and risks related to the ability of MISO's system and software to handle the participation of large numbers of very small" energy storage resources. It asked for a "phased approach in the accommodation of very small" storage resources that would limit participation of small storage resources to 50 in the first year of compliance and 150 in the second year.

MISO said that approach would give it time to "further develop and fine-tune its system and software to be able to handle potentially increasing numbers of very small" storage resources.

Harding Street Energy Storage in MISO | *AES*

But FERC directed MISO to specify what year it expects to provide market access to all storage resources that meet the 100-kW minimum threshold.

MISO must also explain how its must-offer requirement is affected when storage resources elect to use the RTO's proposed dispatch status of "not participating" or other commitment statuses, the commission said. MISO's filing proposed that owners of storage resources could choose between several commitment modes, including charge, discharge, continuous, available, not participating, emergency charge, emergency discharge and outage. MISO has said its discharging, charging and continuous modes will carry must-run designations.

FERC said MISO must clarify whether it proposes to levy transmission charges on storage resources when they are charging to resell energy later. MISO must also explain how it will help storage on the distribution system from making double payments — at both retail and wholesale — for charging energy.

The commission also asked if MISO would propose metering practices to manage the "complexities" of selling energy to a storage resource that will then resell the energy at the wholesale LMP.

FERC said MISO must clarify whether it proposes to levy transmission charges on storage resources when they are charging to resell energy later.

FERC & Federal News

MISO's proposal requires storage owners to secure agreements with distribution companies that can deliver stored energy to the transmission system. FERC asked if MISO would require the same agreements when energy is moved from the transmission system to distribution-level storage, and it asked the RTO to explain a provision that prohibits distribution-level storage resources from pseudo-tying into a different balancing authority.

The commission also told MISO to cite Tariff provisions that will allow owners of storage resources to self-manage their state of charge.

FERC additionally said if MISO were to rely on existing Tariff provisions for a storage participation model, it should provide the commission with citations to the applicable market rules and pseudo-tie requirements for transmission-level resources. MISO must also describe how its filing will give storage resources access to all capacity, energy and ancillary service markets, as well as non-market services such as black start, primary frequency response and reactive power.

The commission told MISO to explain how its filing will prevent the same resource from submitting conflicting supply offers and demand bids for the same market interval. It also seeks to know if the participation model allows for make-whole payments when a resource is dispatched as load and the wholesale price is higher than the bid price and when a resource is dispatched as supply and the wholesale price is lower than the offer price. It also asked if resources available for manual dispatch will be eligible for make-whole payments.

Finally, FERC asked MISO to cite how it will allow storage dispatched as supply and demand to set the wholesale market clearing price as both a wholesale seller and buyer, as Order 841 dictates. The commission also asked for citations to support that storage resources can set the price in the capacity market, that MISO will accept wholesale bids from storage owners and that self-scheduled storage resources can participate in the market as price-takers.

— Amanda Durish Cook

NYISO Asked to Explain Dispatch-only Model

New York regulators in December doubled the state's existing 2025 storage goal to 3,000 MW by 2030, with the Public Service Commission's Dec. 13 storage order (Case *18-E-0130*) accepting with modifications the state's six major utilities' proposed "hybrid tariff" for storage systems paired with eligible electric generating equipment. (See *NYPSC Expands Storage, Energy Efficiency Programs*.)

The commission's letter asked NYISO to explain how its dispatch-only model will allow energy storage resources to reflect commitment costs in their bids consistent with other generators, and whether there are any circumstances that could preclude such a resource from effectively managing its capability to meet obligations through bidding (*ER19-467*).

NYISO said that energy storage resources will not be eligible for dual participation until the ISO develops and implements additional Tariff changes at an unspecified date.

Commission staff also asked whether resources with "limited commercial obligations" such as seasonal retail commitments or other contracts for a portion of the resource's capacity would be prohibited from participating in the ISO's markets. Staff also questioned whether a resource could register only a portion of its capacity as storage with the ISO and reserve the remaining capacity for other customers.

FERC's questions ranged from basic — whether energy storage resources that have start-up costs will have an opportunity to recover these costs — to extremely technical.

For example: "Recognizing that the dispatch-only model alleviates some of the time it takes security-constrained unit commitment (SCUC) to develop a solution, what proportion of the additional time required to solve the SCUC is a result of using a dispatch-only model versus managing these parameters? In other words, could the amount of time saved by foregoing management of these parameters allow for the SCUC to make commitment decisions with an acceptable solve time?"

— Michael Kuser

PJM Queried on Pump Storage, 10-Hour Minimum

The commission cited 10 deficiencies within PJM's proposal, mostly surrounding how existing Tariff language supports its proposed model for energy storage resources (*ER19-469*).

The RTO must first clarify how pumped storage hydro resources comply with Order 841, as well as whether a "capacity storage resource" is included in the definition of a "generation capacity resource" and whether one unit can serve as both.

Invenergy's 31.5-MW Grand Ridge Energy Storage project is 80 miles southwest of Chicago. | *Invenergy*

Earthjustice's Smaczniak said the question indicates FERC is "pushing back" on PJM requirement that storage offering capacity would have to continuously supply energy for 10 hours, which critics have called onerous. ISO-NE sought a two-hour supply, while NYISO proposed a four-hour minimum.

"So I read this as a very positive development for Order 841 implementation!" Smaczniak said.

The commission also wants existing Tariff citations that detail how the RTO will manage electric storage resources, including eligibility for nonsynchronous reserves; exemption from the day-ahead scheduling reserve process; participation in Tier I synchronized reserves; and eligibility for reactive service.

The RTO must also clarify whether a capacity storage resource is included in the definition of generation capacity resource as detailed in Schedule 9 of the Reliability Assurance Agreement. The commission wants more information on the "rules and procedures [that] specifically recognize the unique characteristics and capabilities of capacity storage resources and their relative ability to 'maintain output at stated capability over a specified period of time.'"

PJM must also explain why storage resources deemed "out of charge" wouldn't be considered an outage.

FERC wants to see the specific Tariff language detailing the process for dispatching and self-scheduling energy storage, as well as how the resources can participate as price-takers. Definitions for charge, discharge and continuous mode must also be submitted.

PJM must also detail the annual process energy storage resources must undergo when selecting a participation model and the corresponding Tariff revisions. FERC staff request-

FERC & Federal News

ed more detail regarding how the RTO will avoid conflicting dispatch and how resources in "continuous mode" will serve as demand and supply simultaneously.

FERC also seeks insight into how PJM determines which energy storage resources are eligible to receive make-whole payments, as well as how the RTO's proposed model accounts for minimum state of charge, maximum state of charge, minimum charge time, maximum charge time, minimum run time and maximum run time in existing bidding procedures.

PJM must also explain how operators will use telemetered state of charge in day-ahead and real-time markets and why the RTO believes market sellers don't have to submit minimum charge time, maximum charge time, minimum run time and maximum run time for situational awareness. FERC wants to know if resources can self-manage their state of charge and the penalties for deviating from their dispatch schedules.

The commission also appears skeptical over PJM's position that metering requirements found in Manual 14D apply to energy storage resources because the cited language focuses specifically on telemetry for generators.

— Christen Smith

SPP Queried on LSE Rules

SPP's initial response to Order 841 noted that it does not have a capacity market, but that load-serving entities are subject to a resource adequacy requirement. It said LSEs may designate capacity resources, including storage resources, to satisfy that requirement if the resource meets "the continuous run time requirement applicable to all resource types."

The commission asked SPP to define the "continuous run time requirement" and to identify and describe any additional technical, operational or performance requirements resources must meet in order to qualify as a capacity resource "satisfying an LSE's resource adequacy requirement" (*ER19-460*).

SPP also told FERC that it does not "directly meter" facilities as the order requires to ensure a storage resource resells energy back to the market at the wholesale LMP. Instead, the RTO said, meter agents submit settlement meter values directly to SPP, and it proposed that, "consistent with the handling of pseudo-tied resources, the actual meter values of distribution-sited market storage resources may be split among the retail and wholesale use by the meter agent in both real time and for settlement."

The commission requested SPP explain how its "metering and accounting practices" would comply with Order 841 by ensuring the energy would be resold back to the market at the wholesale LMP and that storage resources would be prevented from paying twice for the same charging energy. FERC also asked how the handling of metering and accounting for distribution-sited storage resources would be "consistent with the handling of pseudo-tie resources."

The commission asked SPP to address deficiencies in three other areas, including storage resources' participation in the markets as simultaneous supply and demand. SPP's proposed tariff revisions would have storage resources "not continuously dispatchable across 0 MW" choose between offering supply or bidding in demand for a given market interval.

FERC requested SPP define a market storage resource that is "not continuously dispatchable across 0 MW," and to explain why including the resources' start-up time constraints in their offer parameters does not allow the RTO to accommodate resources' simultaneous supply offers and demand bids in a given market interval.

The commission asked SPP to clarify how a storage resource will "self-charge" in the Integrated Marketplace, given that the RTO said it does not have a mechanism to explicitly manage their state of charge and "that it does not propose to add any such mechanism." FERC also asked for clarification on whether proposed provisions to "decommit self-committed charging resources" to address insufficient capacity in the day-ahead and intraday reliability unit commitment processes apply to all storage resources or only to "market storage" resources. ■

— Tom Kleckner

CAISO/WECC NEWS

PG&E Names New CEO, Board Members

By Hudson Sangree

Embattled PG&E Corp. named the outgoing head of the Tennessee Valley Authority as its CEO and assembled a "refreshed" board of 13 directors that includes a former FERC commissioner and a member of the Western Energy Imbalance Market's Governing Body, the company announced Wednesday.

PG&E called the moves a response to safety concerns in the wake of catastrophic wildfires.

"We have heard the calls for change and have taken action today to ensure that PG&E has the right leadership to bring about real and dynamic change that reinforces our commitment to safety, continuous improvement and operational excellence," PG&E said in a *news release*.

Critics said the changes didn't go far enough.

"I'm not impressed," said Assemblyman Chris Holden, chairman of the California State Assembly's Utilities and Energy Committee. "I don't see much in this collection that indicates that they are going to watch out for anything but their bottom line, but we'll see. It appears the priority in this selection was protecting shareholders over ratepayers."

PG&E and its utility subsidiary Pacific Gas and Electric are undergoing a Chapter 11 bankruptcy reorganization after two years of massive wildfires left the companies facing billions of dollars in liability. The utility remains on criminal probation for its role in the San Bruno pipeline explosion of 2010. (See *PG&E Wants to Undo Contracts, Revamp Biz in Bankruptcy*.)

Critics have called for major changes in the company's safety culture, and some expressed concern Wednesday that PG&E's new leadership might not be up to the task. The latest changes were backed by three hedge funds that hold large stakes in PG&E, *The New York Times* reported.

"While changes were made in the last few days to augment the safety and government expertise on the board, this proposed board still raises concerns — particularly the large representation of Wall Street interests and most board nominees' lack of relevant California experience," Nathan Click, a spokesman for California Gov. Gavin Newsom, said in a statement.

The changes announced Wednesday include the appointment of Bill Johnson as president


Bill Johnson | *TVA*

and CEO. Johnson replaces former CEO Geisha Williams, who resigned before PG&E filed for bankruptcy protection in January. (See *PG&E Says It Will File Bankruptcy, as CEO Steps Down*.)

Johnson served for six years as head of TVA, the federally owned electricity supplier in the southeastern U.S. He was previously president of Progress Energy, which merged with Duke Energy in 2012. Johnson served as CEO of Duke for less than a day before leaving with a $44 million severance package, news outlets reported at the time.

"During Mr. Johnson's time at TVA, the organization achieved the best safety records in its 85-year history and has been a perennial top decile safety performer in the utility industry," PG&E said in its news release.

'Objectively Failed'


Phil Angelides | *Financial Crisis Inquiry Commission*

The newly named slate of directors, who must be approved at PG&E's next board meeting, is likely to face opposition from unhappy investors at the company's annual shareholder meeting on May 21. BlueMountain Capital, a large PG&E shareholder, has assembled its own slate of directors led by former California State Treasurer and gubernatorial candidate Phil Angelides.

"People need to be clear about what this board is," Angelides said. "After meetings in secret between PG&E and hedge fund investors, [PG&E announced this slate]. I don't think anyone should be under an illusion that this represents a change from the current board or a change in the company."

Nearly half the 13 named members are from hedge funds, Angelides said, and three are incumbents of a board that he said has "objectively failed." PG&E "is in parole. It's in bankruptcy. … This board does not bode well for the company or the people of California," he said.

The utility needs directors with safety experience and green energy credentials, Angelides said. *BlueMountain's slate* of candidates has such members — including Christopher Hart, a former chairman of the National Transportation Safety Board — though it will be an "an uphill battle to dislodge a company-nominated slate," he said.

Angelides served as chairman of the federal Financial Crisis Inquiry Commission, which was charged with investigating the causes of last decade's financial collapse.


Nora Mead Brownell | *© RTO Insider*

PG&E's newly named directors include former FERC Commissioner Nora Mead Brownell, who helped oversee the transition of NERC to FERC oversight during her term (2001-2006). Brownell, who later co-founded energy consulting firm ESPY Energy Solutions, also has served on the boards of directors of National Grid and Spectra Energy Partners and the advisory board of Morgan Stanley Infrastructure Partners.

Brownell did not respond to requests for comment Thursday.

Kristine Schmidt, a member of the EIM Governing Body, was also named as a new PG&E board member. Schmidt worked as a technical adviser to Brownell at FERC. She is president of Swan Consulting Services.

Schmidt could not be reached for comment Thursday. The EIM referred an interview request to PG&E, which said "we'll consider these sorts of requests once our new directors are onboarded."

Cheryl Campbell, former senior vice president of Xcel Energy, was also named as a director Wednesday.

Other members of the updated 13-member board include three holdovers from the current leadership: Richard Kelly, the retired chairman and CEO of Xcel Energy and current chairman of PG&E's board; Fred Fowler, retired chairman of Spectra; and Eric Mullins, co-CEO of Lime Rock Resources, a private equity oil and gas investment firm.

Investment and asset managers make up the remainder of the board, along with a diplomat and an attorney. PG&E said it hopes to confirm the new directors at its next in-person board meeting, "which will be held as soon as practicable," the utility said. ■

CAISO/WECC News

SMUD Goes Live in Western EIM

Continued from page 1

SMUD first announced its intent to join the EIM in October 2016. The nation's sixth-largest community-owned utility, SMUD also is the largest member of the Balancing Authority of Northern California (BANC). Other BANC members — all publicly owned — may eventually join the EIM. (See *SMUD Balancing Area Inks Agreement for EIM Membership*.)

"BANC is excited to be the first publicly owned agency to become an EIM entity in the Western EIM," BANC General Manager Jim Shetler said in the joint statement by CAISO, SMUD and BANC. "We found the CAISO staff to be extremely helpful in assisting us in what was a very smooth transition effort. BANC is currently evaluating future participation by its other members."

BANC, which began operations in 2011, is the third largest balancing area in California and the 16th largest of the 38 balancing areas in the Western Electricity Coordinating Council. Created as an alternative to CAISO, BANC is responsible for balancing load among its members, as well as coordinating system operations with neighboring balancing areas. BANC contracts with SMUD to perform day-to-day balancing functions.

BANC also serves the Modesto Irrigation District, Redding Electric Utility, Roseville Electric Utility, the city of Shasta Lake and the Trinity Public Utilities District. The BA includes a portion of the Western Area Power Administration's transmission grid and the U.S. Bureau of Reclamation's hydroelectric resources in California. The agency's members control capacity on the California-Oregon Intertie, one of two high-voltage transmission lines linking California with the Pacific Northwest.

In its latest statement of benefits, the EIM said its participants have saved nearly $565 million in the five years since the market started. Shifting electricity from where it's overabundant to areas that need it has increased efficiency and allowed the growth of renewable resources, proponents contend. (See *Sacramento Utility to Join EIM; Other BANC Members May Follow* and *SMUD to Join EIM in Spring 2019 at the Earliest*.)

CAISO says the EIM has cut carbon emissions by more than 324,000 metric tons since its 2014 launch by replacing electricity generated from fossil fuels with energy from wind, solar and hydropower resources.

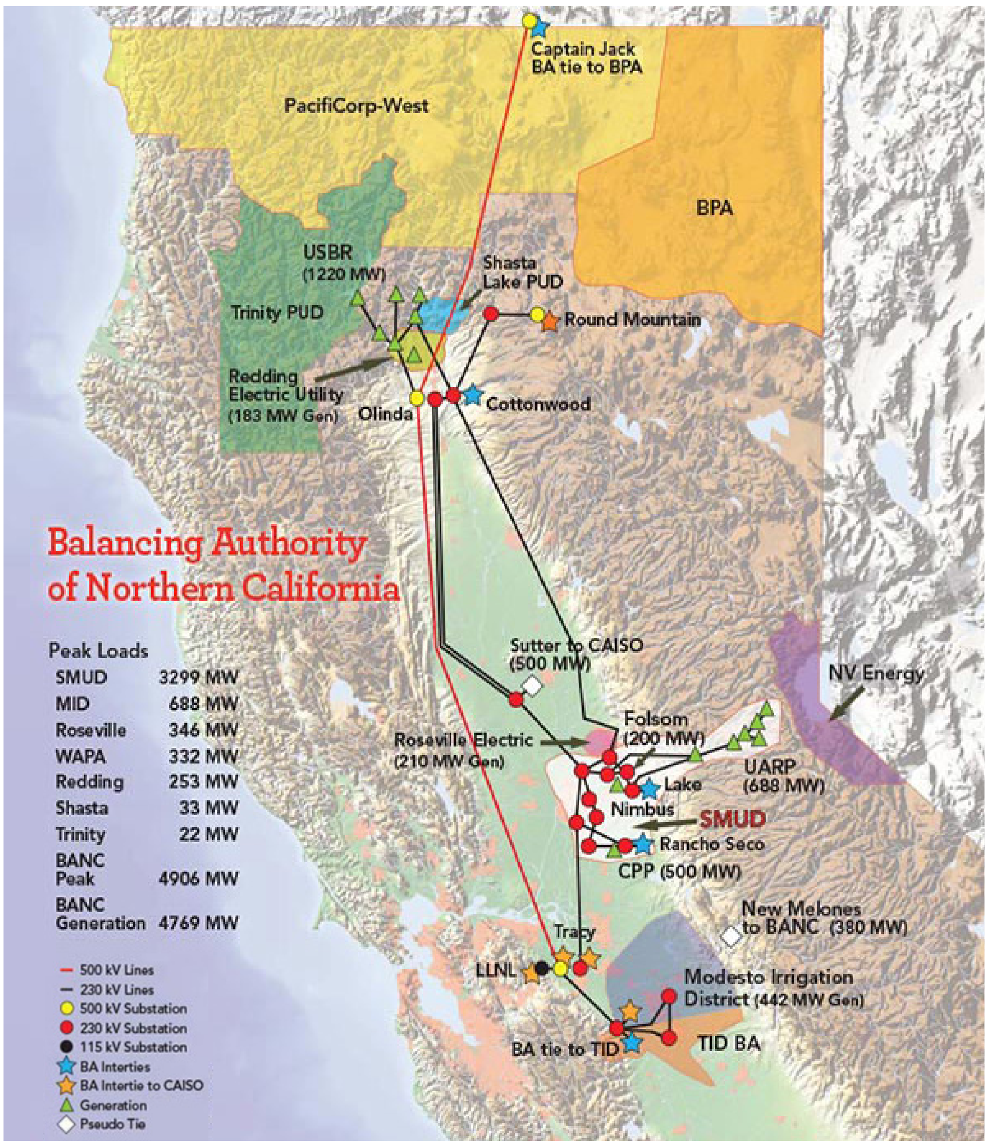
In addition to CAISO, the EIM's other members are PacifiCorp, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Idaho Power and Powerex. Entities scheduled to begin participation next year include Seattle City Light, the Los Angeles Department of Water and Power and Arizona's Salt River Project.

Montana's NorthWestern Energy is planning to join the EIM in 2021. Public Service Company of New Mexico was hoping to join by 2021, but recent regulatory delays have cast doubt on that timing. (See *PNM's Bid to Join Western EIM Gets Approved in Part*.)

The EIM serves areas in Washington, Oregon, California, Nevada, Idaho, Wyoming, Utah and Arizona.

"SMUD sees significant financial, operational and resource value in participating in the Western EIM due to its broader regional scope and dispatch," SMUD CEO Arlen Orchard said in Wednesday's statement. "The EIM's geographic diversity allows easier and more economical balancing and integration of intermittent renewable energy resources, helping SMUD meet its and California's aggressive renewable and carbon-reduction goals.

"SMUD is pleased to have forged this important partnership with the CAISO and the other EIM participants to further these goals." ■



SMUD is the largest member of the Balancing Area of Northern California. | *BANC*

CAISO/WECC News

FERC Rejects CAISO RA Incentive Change

By Hudson Sangree

FERC last week rejected a plan by CAISO to modify an exemption to its Resource Adequacy Availability Incentive Mechanism (RAAIM) that it grants to variable energy resources such as wind and solar (*ER19-951*).

"CAISO proposed RAAIM as a way to provide incentives to resources to meet their resource adequacy must-offer obligations through a series of incentive payments and charges," FERC explained April 1. "CAISO also proposed to exempt certain resources from RAAIM, including variable energy resources," so that they wouldn't be unfairly penalized for weather and other natural circumstances beyond their control.

FERC accepted CAISO's exemption for variable energy resources in October 2015 (*ER15-1825*).

On Jan. 31, CAISO asked to alter the exemption by referencing "participating intermittent resources" and "eligible intermittent resources" instead of "variable resources." The ISO said the change would clarify the exemption because only solar and wind currently can qualify as participating intermittent resources. The proposed change was a product of CAISO's Commitment Cost Enhancements Phase 3 (CCE3) initiative.

"CAISO explains that it has no approved forecasting methodology for other resource types besides wind and solar, and thus it has not offered RAAIM exemptions for them," the commission said.

Pacific Gas and Electric protested, saying CAISO's proposed changes would unfairly exclude certain variable energy resources from the RAAIM exemption, including run-of-river hydroelectric plants that don't have dams and reservoirs.

"PG&E asserts that this proposal would discriminate unjustly and unreasonably against certain types of variable energy resources without adequate justification," FERC wrote. "PG&E explains that certain hydro resources, such as run-of-river hydro, operate similarly to wind and solar in that there is no storage capability, and, thus, no ability to optimally choose when to generate."

In response, "CAISO asserts that these terminology revisions maintain existing application of the bidding and RAAIM exemptions for wind and solar resources … [and] that forecasting run-of-river hydro resources is outside the scope of this proceeding.

"Further, CAISO argues that because its revision maintains the status quo … [it] will have no practical impact because the terms 'variable energy resource' and 'eligible intermittent resource' are interchangeable." The changes would substitute more concrete terms for a generic one, CAISO said.

FERC decided it wouldn't accept the wording change because the ISO had failed to show it wasn't preferential or discriminatory.

When it previously accepted the ISO's proposed RAAIM exemptions, it was so variable resources wouldn't be unfairly penalized, FERC wrote.

"In this filing, though, CAISO proposed to limit eligibility for the RAAIM exemption based on whether CAISO has developed a forecast methodology for that resource," the commission said. "This approach to determining eligibility for the RAAIM exemption is not consistent with the reasoning CAISO originally offered in support of its proposal, and with which the commission agreed."

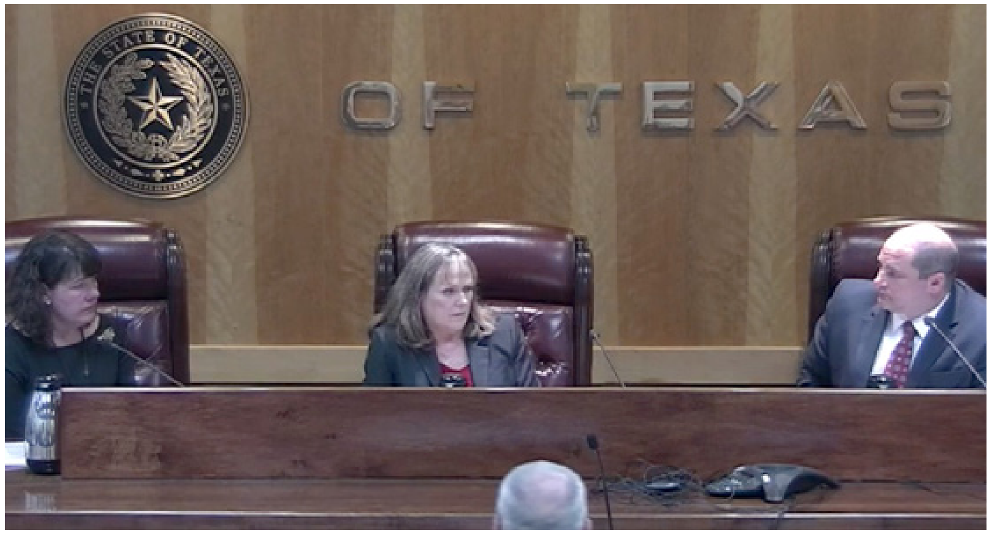
The commission did accept a handful of other Tariff revisions related to the ISO's CCE3 and Reliability Services initiatives, including the following:

- a provision stating resource-specific information that resource owners provide for inclusion in CAISO's master file of resources must accurately reflect the design capabilities of a resource when operating at maximum sustainable performance over minimum run time, recognizing that performance may degrade over time;
- revisions clarifying the integration dates for opportunity cost adders stemming from the CCE3 proposal; and
- provisions clarifying the bidding obligations of resources with limited availability. ■

| CAISO

ERCOT News

Texas PUC Briefs



Left to right: Texas PUC Commissioners Shelly Botkin, DeAnn Walker and Arthur D'Andrea.

PUC Turns Outage Scheduling Issues over to ERCOT

Texas regulators last week praised ERCOT for its response to stakeholder criticism over how it handled an early March cold-weather event that prompted it to ask generators to reschedule planned outages.

Market participants publicly aired their concerns with ERCOT during a Technical Advisory Committee meeting March 27, arguing that the grid operator did not give the market a chance to work and that it had not adequately shared its insight into the market. (See *ERCOT Generators Upset over Early March Weather Event*.)

Since then, ERCOT has begun assembling a task force that will consider improvements to communications and procedures during anticipated emergency conditions; increasing the market visibility of ERCOT forecasts; reviewing how planned outages are delayed or withdrawn; and whether to develop cost-recovery mechanisms for outages postponed or canceled because of reliability reasons.

That was enough for the Texas Public Utility Commission to wave off a presentation by ERCOT Senior Director of System Operations Dan Woodfin during its open meeting Thursday. Woodfin had planned to deliver the same presentation he gave during two hours of discussion before the TAC.

"I'm happy to see you have a process now and you're working on it," Commissioner Arthur D'Andrea told Woodfin. "That's promising to restore some confidence in the market and make some changes."

| © RTO Insider

"I would like the market participants to work this out at ERCOT, like we typically do," PUC Chair DeAnn Walker said. "ERCOT acknowledges they can do things better. I've told everyone I'm not interested in going back and punishing anyone for anything that happened. I don't want anyone dwelling on putting more arrows in Dan, because he got more than he deserved at TAC."

The PUC opened a proceeding on ERCOT's outage scheduling processes (Project *49378*) and was moved to action after South Texas Electric Cooperative *filed* a complaint. STEC said it received an instruction to reschedule an outage at its 400-MW, lignite-fueled San Miguel plant less than 12 hours before maintenance work was to begin.

"ERCOT exercised what amounts to a free capacity call option ... at great risk to both those generators and the market that have to perform maintenance or risk being subject to forced outages during the period of the lowest reserve margins the ERCOT market has ever seen," STEC said.

Oncor ARR Reduced by $218M

The commission consented to Oncor's request to reduce its annual revenue requirement by $218.8 million as a result of the Tax Cuts and Jobs Act of 2017 (Docket *48325*).

The PUC directed Oncor to apply a 3.25% carrying charge to the amount of federal income tax expense it collects above the amount it would have collected since Jan. 1, 2018.

The commission also consented to staff's *wholesale transmission service charges* for transmission and distribution service providers operating in the ERCOT system (Docket *48928*).

Sempra-Oncor-Sharyland Hearing

The PUC held a prehearing conference Monday to accept exhibits for its April 10-12 hearing on proposed transactions involving Sempra Energy, its Oncor subsidiary, Sharyland Utilities, and Sharyland Distribution & Transmission Services (Docket *48929*).

The companies in October announced deals worth $1.37 billion, with Sempra buying a 50% stake in Sharyland D&T and Oncor acquiring transmission owner InfraREIT. (See *Sempra, Oncor Deals Target Texas Transmission*.)

AEP Texas, Oncor Propose Asset Swap

AEP Texas and Oncor have filed an *application* with the PUC requesting transfer to AEP Texas of Oncor's distribution assets and associated certificate of convenience and necessity rights in the Rio Grande Valley cities of McAllen and Mission (Docket *49402*).

Under the proposal, AEP Texas would acquire Oncor's distribution assets, valued at about $18 million, and about 54,000 retail distribution customers. Oncor acquired the customers during an asset swap with Sharyland Utilities in 2017. (See *Texas PUC OKs Settlement in Oncor-Sharyland Asset Swap*.) ■

— Tom Kleckner

ERCOT News

ERCOT Briefs

Task Force Begins Work on Real-time Co-optimization

ERCOT staff and stakeholders began the long process of implementing real-time co-optimization (RTC) last week with the first meeting of the Real-Time Co-Optimization Task Force.

Matt Mereness | © *RTO Insider*

The group spent its *Thursday meeting* reviewing ERCOT's current market design and the changes that RTC will necessitate. ERCOT Compliance Director Matt Mereness, the task force's chair, said it's important to understand the elements in RTC's high-level design principles in order to better understand what is being implemented.

"We have a mandate to implement real-time co-optimization, and we will be working to see what market functions have to be changed to enable that," Mereness said.

RTC is supposed to efficiently coordinate the provision of energy and ancillary services (AS) in the real-time market and price AS shortages according to their defined demand curves. Its elements include: real-time market and AS deployment; reliability unit commitment; day-ahead market operations; internal and external reporting; and performance monitoring.

Implementation of the process will mean the loss of ERCOT's supplemental AS market.

The Texas Public Utility Commission directed ERCOT to implement RTC earlier this year (Project *48540*). The grid operator has said it will take four or five years and about $40 million to add RTC to the energy-only market.

Bryan Sams, director of regulatory affairs for Lone Star Transmission, is serving as the RTCTF's vice chair. The group is composed of stakeholders and staff from ERCOT, the PUC, the Independent Market Monitor and the Office of Public Utility Counsel. The task force will report directly to the Technical Advisory Committee.

ERCOT to Ask Board for NPRR916 Changes

ERCOT will ask its Board of Directors during its bimonthly meeting today to accelerate the implementation date for a previously approved Nodal Protocol revision request (NPRR) and to change its mitigated floor offer as a result of negative gas prices.

The TAC endorsed *NPRR916* on March 27. The change sets the mitigated offer floor to $0/MWh for "combined cycle" (CCGTs) and "gas/oil steam and combustion turbine" (CTs) resource categories, replacing the fuel index price-based (FIP) calculation. The change also eliminates the grey-boxed language from *NPRR664*.

During a Thursday webinar, staff explained that negative fuel prices at the Waha Hub coupled with mitigated floor offers are creating "irrational restrictions" for CTs and CCGTs.

When gas prices are negative, a floor of zero is excessive relative to the resource's optimal offer, staff said.

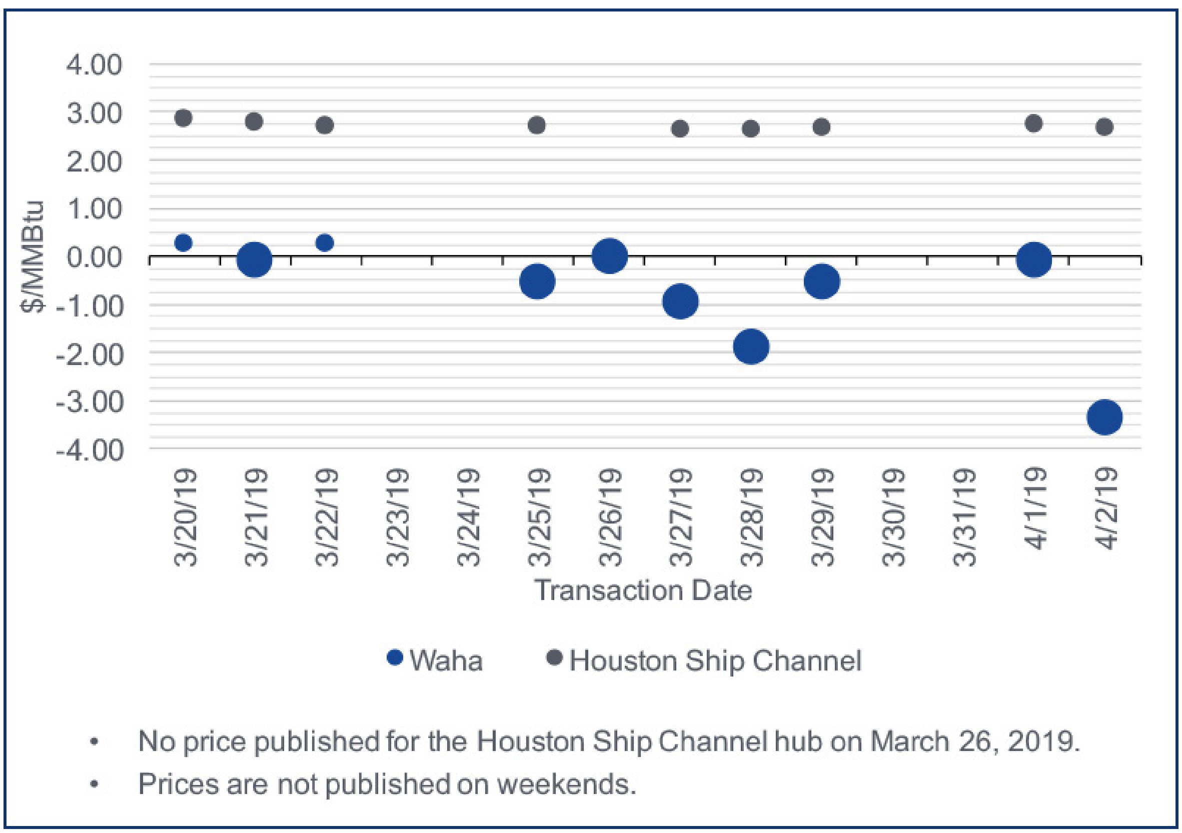
ERCOT wants to change the offer floor to -$20/MWh, aligning CTs and CCGTs with coal and lignite units' offer floor.

The grid operator also wants to move up implementation of NPRR916 from May 1 to April 10. Staff said West Texas fuel prices support the need to "make this system adjustment as soon as practicable." The proposed change to -$20 requires modifications to ERCOT systems that would become effective upon system implementation.

The current floor for CCGTs is set at 1 MMBtu/MWh x FIP, and 6 MMBtu/MWh x FIP/FOP (fuel oil price) for CTs and gas and oil steam turbines. NPRR916 changes those numbers to a straight value of $0/MWh.

The NPRR916 changes are expected to cost less than $10,000 and will be absorbed by ERCOT's operations and maintenance budgets, staff said. ■

— Tom Kleckner



Texas Natural Gas Prices | *ERCOT*

ISO-NE News

ISO-NE Filing, White Paper Address Energy Security

By Michael Kuser

A new ISO-NE white paper attempts to chart a course for the RTO to develop new market-based solutions to overcome New England's long-term energy security challenges.

The RTO issued the *white paper* to the New England Power Pool Markets Committee just a week after filing an interim *proposal* with FERC to address winter energy security for the commitment periods covered by Forward Capacity Auctions 14 (2023/24) and 15 (2024/25).

The nearly 400-page interim plan calls for a voluntary two-year program to "provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed" (*ER19-1428*).

The RTO made the filing despite last month's rejection of the proposal by the NEPOOL Participants Committee. Members also rejected a proposal by energy services firm Energy New England that would have limited compensation to oil-fired and certain natural gas-fired resources, demand response and electric storage resources. (See *ISO-NE Steady on Fuel Plan Despite NEPOOL Rebuff*.)

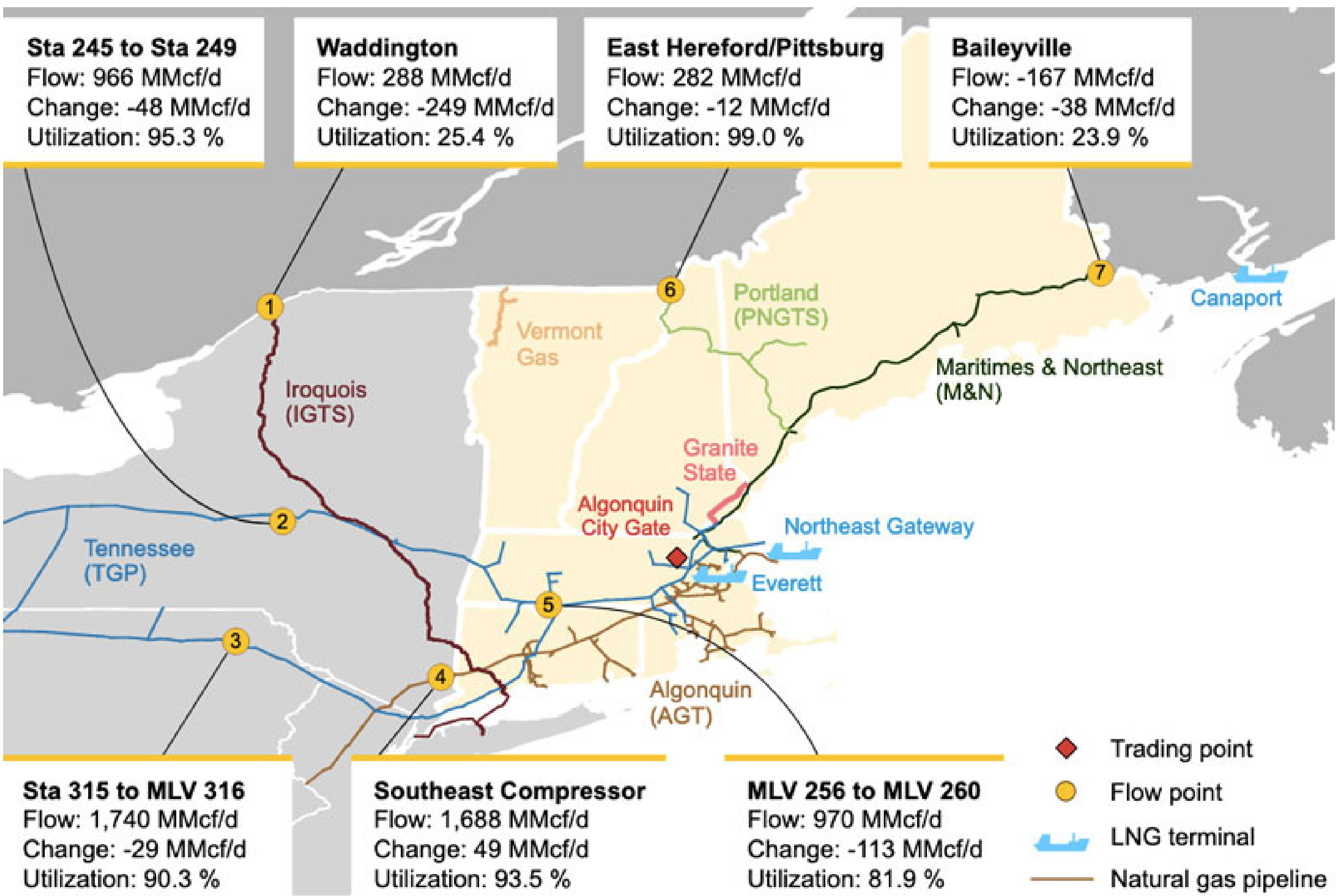
Pulling the Trigger

ISO-NE's interim program consists of five core components, including a two-settlement structure, a forward rate, a spot rate, trigger conditions and a maximum duration for compensation.

Under the proposal's two-settlement structure, resources would be paid or charged for deviations between the forward rate of $82.49/MWh for inventoried energy purchased in a forward position for the entire winter season and the spot settlement rate — $8.25/MWh — representing energy maintained during each trigger condition.

An "inventoried energy day" under the program is triggered for any day in December, January or February when the average of the high and low temperatures on that day, as measured at Bradley International Airport in Connecticut, is less than or equal to 17 degrees Fahrenheit.

The program's maximum duration of 72 hours of generator compensation is designed to account for the incremental reliability benefit of another megawatt-hour of inventoried energy, decreasing as a resource maintains a greater



Many New England gas pipelines are subject to high capacity utilization rates, prompting ISO-NE to seek ways to ensure future fuel security for a grid increasingly dependent on just-in-time deliveries to gas-fired power plants. | *EIA*

ISO-NE News

quantity of inventoried energy, according to the filed *testimony* of Christopher Geissler, the RTO's market development economist.

Adding another megawatt-hour of inventoried energy to a resource able to operate for 12 hours may improve the region's winter energy security; however, if a resource has enough inventoried energy to operate for six months, then adding another megawatt-hour of inventoried energy "is unlikely to have a material effect," Geissler testified.

Todd Schatzki, vice president of Analysis Group, testified on behalf of ISO-NE and estimated the program's costs at $148 million per year, corresponding to approximately 1.8 million MWh of inventoried energy sold forward and maintained during trigger cold days throughout the winter.

"As these assumptions reflect maximum program participation, in a sense, this estimate provides an upper bound on the program's potential costs, assuming forward settlement of all inventoried energy and no change in the region's infrastructure," Schatzki said.

Program participation may differ from assumptions, he said. For example, through lower-than-expected LNG contracting, resources may not supply the maximum eligible quantity of inventoried energy into the program, or resources may supply only a fraction of their capacity through forward settlement, which could lead to higher or lower payments if the number of very cold days differs from the number assumed in setting the forward settlement rate.

Fast and Easy, or Not

FERC in December approved ISO-NE's initial Tariff revisions to use an out-of-market mechanism to address concerns about fuel security, filed after the commission in July denied a Tariff waiver to allow the RTO to enter a cost-of-service agreement to keep Exelon's 2,274-MW Mystic plant running after its capacity obligations expire in May 2022.

The commission encouraged "ISO-NE to work with all interested parties, including NEPOOL, to continue to address their areas of disagreement while developing the long-term market solution." (See *ISO-NE Fuel Security Measures Approved*.)

Ahead of NEPOOL discussions over the next six months on a long-term solution, the interim program first had to be simple enough to be designed and filed quickly, and not overly complex to implement, the RTO said.

Second, to be effective, the program should compensate resources that provide winter energy security. And third, "it should be designed consistent[ly] with sound market design principles, most notably providing similar compensation for similar service," Geissler said.

Looking Ahead

The RTO's white paper looks at the region's needs beyond FCA 15. To accommodate the complexity needed in a long-term solution, the document broadly recommends "expanding the existing suite of energy and ancillary service products" in the markets to address "the uncertainties and supply limitations inherent to a power system evermore reliant on just-in-time energy technologies."

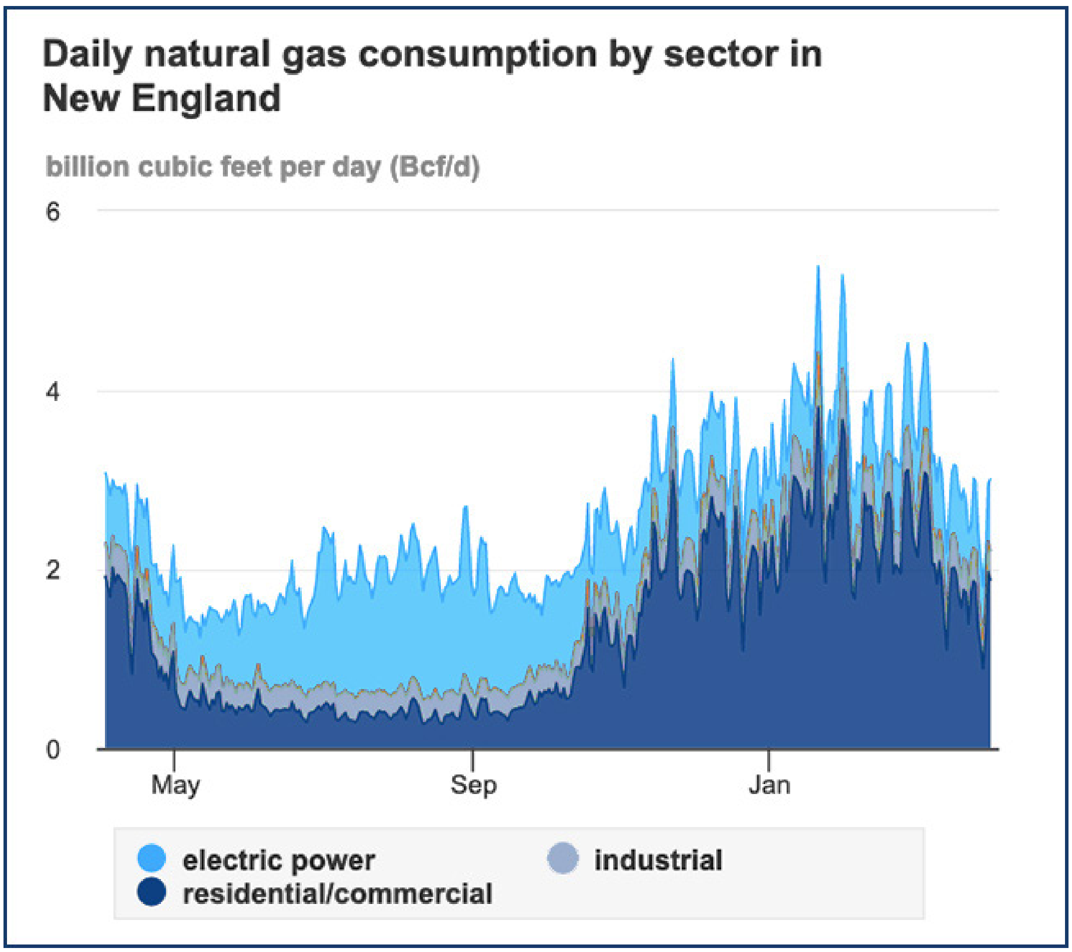
Three core components intended to spur discussion are a multi-day-ahead market, new ancillary services in the day-ahead market and a seasonal forward market.

The first would optimize energy, including stored fuel energy, over a multiday time frame and produce multiday clearing prices for market participants' energy obligations.

The second component would create several new, voluntary ancillary services in the day-ahead market to provide, and compensate for, the flexibility of on-demand energy.

The seasonal forward market would see the RTO conduct a voluntary, competitive forward auction to incent and compensate asset owners to invest in supplemental supply arrangements for the coming winter, the white paper said.

Referring to the paper, Marcia Blomberg, ISO-NE's senior media relations specialist, said: "The ISO committed to posting this by April 1 to give stakeholders a basis for discussion as we work with them to refine the proposal to be filed at FERC by Oct. 15." ■



New England natural gas flows | *EIA*

MISO News

MISO Closer to Clearing up Queue Extension

By Amanda Durish Cook

FERC last week conditionally accepted MISO's second attempt to address an inherent conflict within its Tariff related to the termination of generator interconnection agreements (GIAs) (*ER18-2054*).

The conflict stemmed from a discrepancy between what was laid out in MISO's generator interconnection procedures (GIP) and its *pro forma* GIA.

In an October 2017 order, FERC found that a provision in the GIA allowing interconnection customers to extend the commercial operation date (COD) of a project by up to three years without facing termination conflicted with a GIP provision stating a COD extension required a material modification of the interconnection request — or the project risked removal from the queue. The discrepancy was discovered when the Merricourt wind project in North Dakota sought to extend its COD under a GIA with Montana-Dakota Utilities and MISO.

In mid-2018, FERC directed MISO to make a second Tariff filing clarifying an interconnection customer can extend its COD by up to three consecutive years before risking withdrawal from the queue. (See *FERC OKs MISO Revision of Queue Termination Rules*.) At the time, FERC directed MISO to "provide clarity as to the three-year period that must lapse before MISO must seek to terminate a GIA for failure of a generating facility to achieve commercial operation by the [COD]."

MISO's updated Tariff language clarifies that an interconnection customer's project has up to three years beyond its original COD to begin generating or risk removal from the interconnection queue.

The GIP now explains that once a GIA is executed or filed unexecuted, "if the generating facility fails to reach commercial operation by the [COD], such [COD] may be extended by [the] interconnection customer for a period up to three consecutive years, after which [the] transmission provider shall terminate the GIA if the generating facility has still failed to reach commercial operation."

In its filing, MISO relayed concerns that the new GIP language could inadvertently allow a maximum six-year extension to a generating facility's COD by creating a three-year maximum extension that is "distinct" from the same three years allotted in the GIA. That could occur when a project's timeline is jeopardized by a change in milestone fees by another party to the GIA, a change in a higher-queued interconnection request and delays in MISO studies; and when an interconnection customer can show that engineering, permitting and construction will take longer than the definitive planning phase allows. None of the four exceptions amounts to a material modification under MISO Tariff.

FERC agreed with MISO that the language could be construed as creating an "additive" three-year extension that is "distinct from, and in addition to, the three-year extension that an interconnection customer may receive if it qualifies for any of the four exceptions."

To avoid that reading, the commission April 1 directed MISO to make a further compliance filing to reference that the new GIP language is consistent with the provision in its pro forma GIA that limits the COD extension to three years. ■

| MISO

MISO News

Mich. Energy Storage Idea Poses New Life for Old Mines

By Amanda Durish Cook

Old and new will interconnect in an innovative way if researchers at Michigan Technological University can pull off an energy storage concept that pairs some of the state's abandoned and flooded mines with hydroelectric pumped storage.

Researchers and students at the university are studying the *possibility* of using an abandoned mine in the Upper Peninsula for underground pumped hydroelectric storage. Representatives from Michigan Tech and the city of Negaunee say floodwaters from the lower levels of the mines could be pumped to higher, dry levels, using old excavations as holding tanks. Such a system would be essentially invisible, leaving the surface undisturbed, they say.

Roman Sidortsov, assistant professor of energy policy, said the pilot landscaping study is focusing on Negaunee's *Mather B*, an iron mine that ramped up production after World War II and shuttered at the end of the 1970s.

The two-year pilot, funded by a $50,000 grant from the Alfred P. Sloan Foundation, will likely produce a report this fall on whether an underground pumped hydro storage facility is technologically and environmentally feasible. Sidortsov said the report will be intended for a broad audience, including "developers that contemplate energy storage projects and policymakers who might support them."

The research team will hold an April 26 brown bag lunch meeting where students who have been working on various aspects of the study will present their preliminary results, followed by a May 7 community meeting in Negaunee to provide updates on the pilot.

Researchers are at a preliminary stage in the project after holding the first meetings in December. Sidortsov said he and others are now waiting for a few feet of snow to thaw to begin accessing the mine, with student researchers planning on bringing snowshoes to assess the area.

Abandoned mine in Negaunee | *reddit user MassaEwas*

"We live in a snow globe up here," Sidortsov said in a telephone interview with *RTO Insider*. "We were helped in identifying the mine with city planners."

For now, the work is focused on a "preliminary analysis to identify next steps," Sidortsov explained. However, he said early engineering analyses relying on mine dimensions supplied by city planners are "incredibly optimistic."

"We cannot wait to confirm those numbers," he said.

According to Sidortsov, the "very, very back of the envelope numbers" show Mather B might be able to support up to a 50-MW nameplate capacity facility that can provide continuous output for up to three hours at a time. The facility would use surplus energy for pumping.

The idea is for a singular storage facility, but Sidortsov said research could show it's more efficient to install multiple facilities in separate mineshafts.

Timothy Scarlett, Michigan Tech associate professor of archaeology and anthropology, said he and Sidortsov will have a better understanding of the feasibility of the project in July and August.

Until then, "we've been trying to underpromise and overdeliver," Scarlett said.

Meanwhile, Michigan Tech students have already started research on surface water runoff and cybersecurity issues that could affect such a storage facility.

'Post-industrial Landscape'

The researchers say this initial study is being conducted backward when compared to how a utility might approach a new generation project, where the design and engineering work typically come before community meetings.

Scarlett and Sidortsov said they began their work by engaging community leaders. It's how they learned the team should choose the Mather B site instead of the original choice, the nearby Jackson mine, where a deadly accident had left miners entombed. Scarlett said the early meetings helped to uncover local sensitivities about different mines in the area. On advice from city officials, the Jackson mine was left alone out of respect for the families of the dead.

"Community members feel differently about

MISO News

different historic mines," Scarlett said, adding that social acceptance of such a project is important in "post-mining, post-industrial" communities.

"It's a sensitive issue for the community. In doing some of the research, we encounter things like this," Sidortsov said.

Both researchers stressed there is no agenda to the research.

"One of the advantages of running a study like this is we don't have an ulterior motive. Even if we're proven wrong in our endeavor, it will be a bummer, but it will still be an important discovery," Sidortsov said.

He said the pilot study will yield important insight into water control and quality, necessary proximity to transmission lines and other information that can be used for similar projects in other mines in the area. About 20 years ago, Michigan Tech *cataloged* more than 800 mines in the western Upper Peninsula alone.

However, if all goes well, Scarlett said they hope to use the pilot project as a launch to seek funding for a nationwide project on hydro pumped storage in abandoned mines. Sidortsov said even dry mines could host chemical battery storage or completely flooded mines could house compressed air storage.

"We're not a developer; we're not proponents of any kind of technology," Sidortsov said.

But the researchers do have a certain backdrop in mind for such storage projects.

"The idea is to stick with this post-industrial landscape," Sidortsov said. "What we're also trying to do is directly appeal to the policymakers in Michigan."

The two are examining how such a concept might be monetized, boosted either by state-level tax credits or other financial incentives.

"This can be a transmission resource. This can also be the base around which distributed energy resources can be built," Sidortsov said. "It gives an opportunity for intermittent resources to be connected to the grid. It also does present opportunities for grid resilience because it's localized and you're not depending on one large transmission line."

But Sidortsov said Michigan Tech will look into the facility performing in several ways, including providing ancillary, capacity, generation and transmission services.

"We're not bound by a particular use," Sidortsov said.

The two are also hopeful that mine energy storage could help alleviate customer bills in the Upper Peninsula, which has been subject to expensive energy rates and multiple past system support resource agreements that fund aging coal-fired plants needed to serve the transmission-constrained region.

"We're representatives of that customer group by virtue of our bank accounts, so the pain is personal," Sidortsov joked.

Prohibitively high energy costs are also a concern for local governments, Scarlett said. "The leaders of these communities have identified this as one of their major concerns to economic development."

'Attractive' Sites

The researchers still must track down the most recent maps of the mine and figure out what entity — if any — might still have rights to the underground areas. Sidortsov and Scarlett say, so far, they know the rock in which Mather B is situated has "soft" upper layers that were heavily reinforced in the 1970s. The upper levels of the mine might only need to be grouted to create a watertight reservoir, they said.

"Unlike a greenfield site that you would have to study, these mines come with a complete geological and hydrological study. It's another reason why these sites are so attractive," Sidortsov said.

He also said the mine's year-round stable climate is a particular advantage for hydropower design. "You have essentially the same conditions year-round," Sidortsov said. "With other hydroelectric sites, production varies with snowfall, rainfall ... how much ice is on the river. Here, you don't have that problem."

The researchers also say the Upper Peninsula's mines' historic powerhouses might be adapted to connect the storage to the grid.

Even permitting might prove less of a headache, Scarlett said.

"The rights of way might still be there; you may not have to pay for them," Scarlett said.

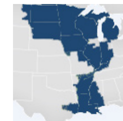
The ultimate goal, Scarlett said, is a "respectful design" in harmony with the original function of the mine's industrial character. He said a plan that disturbs little while repurposing the mine might allow developers to access funds and credits that states or municipalities dedicate to historic preservation and adaptive reuse of historically important structures.

Sidortsov said the idea so far is receiving a surprising amount of bipartisan support in the state.

"Tim and I were just geeking out, then we quickly discovered it wasn't just us," Sidortsov said of the project's roots. ■

Surface shot of the Mather B mine hoist house taken sometime during the mid-century | *Michigan Tech archives*

MISO NEWS



Entergy Lays out New Carbon Reduction Goals

By Amanda Durish Cook

Having met its current carbon reduction goal ahead of schedule, Entergy now says it plans to further slash emissions over the next decade to well below levels seen 20 years ago.

In a report issued Wednesday, Entergy said it is "intensifying" its efforts, pledging to reduce its CO_2 emission rate to 50% below 2000 levels by 2030. If achieved, the company would produce about 24.6 million short tons of annual emissions, compared with 36 million short tons in 2017.

The announcement was rolled into Entergy's 2018 ***Integrated Report***, which combines the company's annual shareholder report with its sustainability report. The company has already surpassed its previous commitment to reduce emissions to 20% below 2000 levels by 2020.

"The broad consensus of current scientific data on climate change indicates that, as an industry, we must do more to reduce our footprint and that of our customers and communities. Entergy sees this not as a choice but as a responsibility and an opportunity," Entergy CEO Leo Denault wrote in a letter to stakeholders. "Speaking plainly, this means that for every unit of electricity we generate in 2030, we will emit half the carbon dioxide we did in 2000."

In 2018, Entergy's utility-only CO_2 emission rate was 763 pounds/MWh, lower than the national average of 1,009 pounds/MWh. The 2018 emissions rate represented a 28% reduction from 2000.

Since announcing its portfolio transformation strategy in 2002, Entergy says it's replaced almost 30% of its older generating assets. Natural gas-fired generation now represents 60% of the company's more than 25 GW in generating assets.

While Entergy is not releasing a supply plan, it did say the new goal could mean a supply mix that's 60% natural gas, 32% nuclear, 7% renewable and slightly more than 1% coal.

Entergy estimates it currently has about 1 GW of renewable projects in "various stages of development."

Denault added that Entergy's 8.8-GW nuclear ***portfolio*** is a "critical source of safe, large-scale and virtually emission-free baseload power" that could make or break the company's sustainability goals. Preserving the plants is crucial, he said.

Those statements come at a time when Entergy is seeking to offload two nuclear units outside its service territory to a subsidiary of Holtec International. Entergy expects to complete the sales of the Pilgrim plant in Massachusetts by the end of 2019 and Palisades plant in Michigan by the end of 2022. The sales are part of the company's strategy to exit the merchant power business and re-establish itself as a pure-play regulated utility.

Entergy also released a ***separate*** analysis and risk assessment on climate change. The company concluded it should focus on coastal wetland restoration, renewable generation, grid modernization, emergency response, energy efficiency and electric vehicles. It also said it's designing facilities that can withstand flooding and extreme weather events.

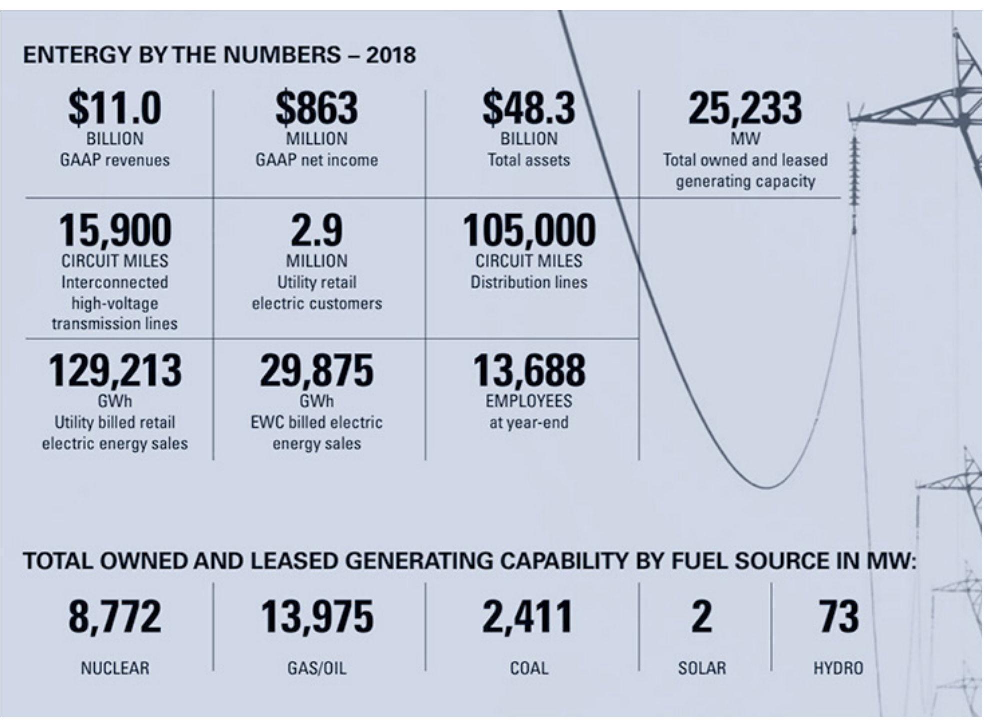
The company is simultaneously planning for load reduction, as customers invest in distributed resources, and load growth, from increased demand for cooling and refrigeration. It expects climate change impacts to be "especially pronounced" in coastal Louisiana and Texas, where risks from sea level rise, damaging storms and coastal erosion are highest. The company also predicted "potentially disproportionate" impacts for its low-income customers.

None of the four states in Entergy's utility service territory has passed carbon emissions regulations, though Texas has a renewable portfolio standard and New Orleans has published a ***climate action plan*** aimed at halving emissions by 2030. However, Entergy predicts that a federal carbon tax will soon become a reality.

Entergy said it would hold off on making plans around any technologies it might adopt until they prove cost-effective.

"Some of the technologies viewed as necessary to reduce greenhouse gas emissions consistent with a 2-degree [Celsius] scenario do not exist today. Others currently are not commercially viable and would require significant resource investments to adopt at a scale that is cost-competitive with conventional generation resources," Entergy said.

The company also said simply halving its total emissions by 2030 isn't feasible. To meet a 50% net reduction in emissions by that time, the company said it would have to increase its zero-carbon generation from the current 37% of the fleet mix to nearly 55% by 2030. One analysis showed Entergy would have to add 9.8 GW of solar capacity and 5.3 GW of battery storage in order to achieve the reduction, a scenario the company deemed unrealistic. ■



| *Entergy*

NYISO News

NY Examines VDER Capacity Value Compensation

By Michael Kuser

New York officials, utilities and solar energy advocates are trading comments through the state's Public Service Commission on what constitutes appropriate compensation for the capacity value of distributed energy resources (VDER) (Case *15-E-0751; 15-E-0082*).

The comments come after the PSC in December issued a staff *white paper* regarding capacity value compensation and in January ruled that John F. Kennedy International Airport could have a solar project up to 5 MW compensated under the VDER program while having other solar projects dedicated to serving on-site load (Case *18-E-0766*). (See *NYPSC Clarifies Value Stack Capacity Limits*.)

In the value stack white paper, Department of Public Service staff recommend replacing the market transition credit (MTC) model, a value based on installed capacity estimates, with a new "community credit" model to compensate participants of community distributed generation (CDG) projects.

The commission's original VDER order in March 2017 directed that the state's compensation scheme for eligible DER transition from net energy metering (NEM) to the value stack, which bases compensation on provided benefits. The PSC's Jan. 17 declaratory *ruling* said, "The rated capacity of projects used solely for serving on-site load and not seeking compensation under the value stack or net metering should not be counted towards the rated capacity limit."

Rate Design

The DPS' Utility Intervention Unit (UIU) filed *comments* that addressed rate designs for post-NEM mass market customers — those with eligible on-site generation.

"The proposed rate relies in part on advanced metering infrastructure (AMI) capability, which New York utilities have not yet fully implemented," the UIU said. "Thus, to the extent that AMI is required to participate in this rate, the proposal appears premature."

The Clean Energy Parties (CEP) — an ad hoc group including the Solar Energy Industries Association, Coalition for Community Solar Access, Pace Energy and Climate Center, Natural Resources Defense Council, New York Solar Energy Industries Association and Vote Solar — filed *comments* supporting DPS staff's recognition "that some aspects of the tariff, such as DRV [demand reduction value], were achieving a false sense of accuracy and recommends changes that will better align the financial signals sent to customers with the benefits they can provide to the distribution system."

The group said that for more than a year they have "made the case that the current tariff does not accurately reflect the value of distributed energy resources or provide stable enough compensation." The state's utilities show "a surprising misunderstanding of the development process for medium-sized to larger-sized solar energy facilities," it said.

Utilities — including Central Hudson Gas & Electric, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power, Orange and Rockland Utilities, and Rochester Gas and Electric — *dismissed* New York City's advocacy of a higher MTC for Con Ed as unnecessary.

In addition to the 18 MW of projects identified in Tranche 0/1 as of March 1, 2019, Con Ed's interconnection queue contains an additional 84.7 MW of eligible projects, including 42.5 MW of fuel cell projects, the utilities said. Because fuel cells are expected to operate at capacity factors in excess of 90% and achieve a high coincidence with the DRV, they will have the same cost impact as roughly 255 MW of solar installations, they said.

Resource Eligibility

The PSC last September expanded the eligibility of DER to be compensated under the state's value stack tariffs, particularly standalone storage systems with 5 MW or less of capacity, including crediting to any clean generation technology that qualifies as a Tier 1 resource under the Clean Energy Standard (CES).

The new rules also make resources eligible for compensation that would qualify for Tier 1 but for their start date before Jan. 1, 2015, and also authorize interzonal crediting, allowing DERs receiving value stack compensation to apply credits to the bills of customers in the same utility territory but different NYISO load zones. (See *NYPSC Takes Subway into Value Stack*.)

In responding to the white paper, the utilities suggested that, rather than exposing customers to long-term commitments that provide limited customer benefits, DRV compensation should be tied to DER production during each utility's service territory-specific peak hours.

A 2-MW solar project at Mohawk Valley Community College was supported by a grant from the New York State Energy Research and Development Authority. | *NYSERDA*

"To the extent that the current 10-peak-hour window creates more volatility than is deemed necessary to support development of eligible resources, a modest expansion to 50 hours may be appropriate," the utilities said. "Similarly, the [state's] Office of General Services argues that behind-the-meter generation should also be eligible for value stack compensation. This proposal should be rejected as customers using generation to offset their usage are already avoiding distribution and energy charges."

The utilities opposed creating a community credit, but if one is established, they also oppose the recommendation by large commercial and industrial end-users that its costs be allocated only to residential customers, favoring instead the same methodology as the MTC, which allocates costs to those customer classes that receive the benefit.

They also recommended that the PSC reject the CEP's suggestion to establish a Distribution Planning Advisory Committee, saying that "such a committee is unnecessary and would duplicate the existing Distributed System Implementation Plan Advisory Committee" and also create an additional burden on stakeholder resources. ■

NYISO News

FERC Denies NYDEC Rehearing on Northern Access

By Michael Kuser

Cattaraugus Creek in western New York is one of 192 streams crossed in the state by the Northern Access pipeline route. | *National Weather Service*

FERC last week denied requests by New York state officials and the Sierra Club for rehearing and stay of its determination that the state had waived its authority to issue or deny a water quality certification for the Northern Access natural gas pipeline (*CP15-115-004*).

National Fuel Gas Supply's proposed 97 miles of pipeline would be capable of carrying about 500 MMcfd of gas from western Pennsylvania to the Buffalo area and also interconnect with the TransCanada pipeline.

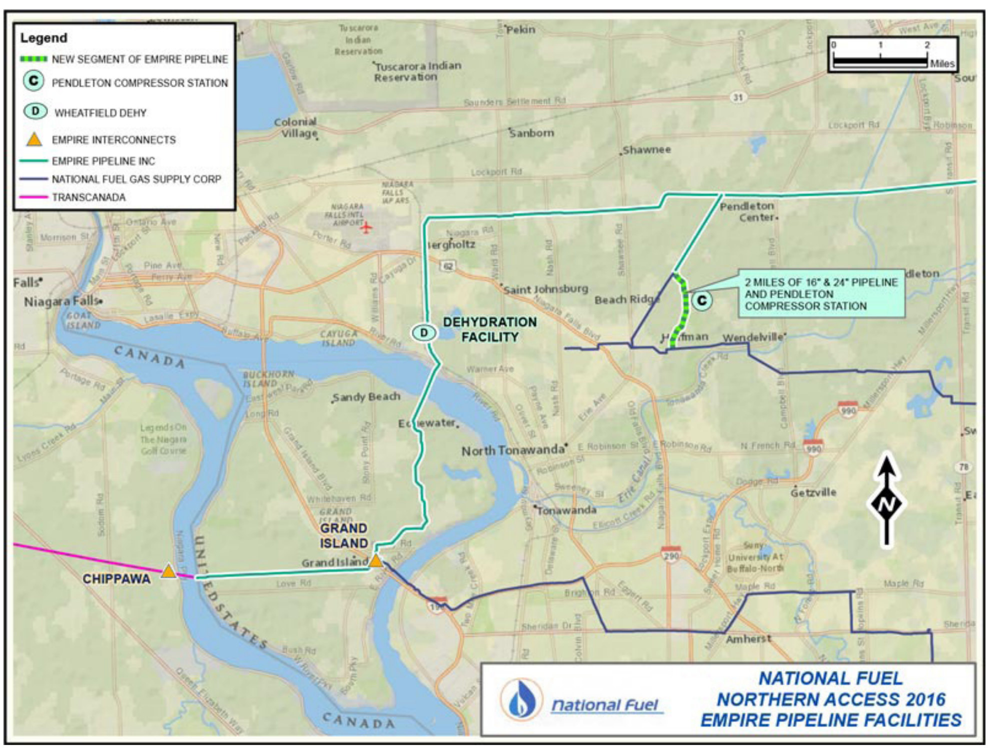
The commission last summer ruled that the state Department of Environmental Conservation had waived its authority to issue or deny a water quality certification under Section 401 of the Clean Water Act by failing to act within one year of receiving National Fuel's application.

The case hinges on the date of receipt of the application, which FERC asserts was March 2, 2016, but which the DEC contends was changed by agreement with National Fuel to April 8, 2016. The department denied the application on April 7, 2017.

In its April 2 ruling, the commission faulted the DEC for citing cases that address waiver of rights in criminal proceedings, saying, "by contrast to the statutory schemes at issue in the cases cited by New York DEC, the Section 401 deadline cannot be waived by agreement."

The commission cited *Hoopa Valley Tribe v. FERC*, in which the D.C. Circuit Court of Appeals considered whether waiver occurs when there is a written agreement to delay water quality certification. The court concluded that such an agreement constituted a failure and a refusal to act under Section 401.

"Hoopa Valley Tribe determined that a 'deliberate and contractual idleness' not only usurps the commission's 'control over whether and when a federal [authorization] will issue' but would contravene Section 401's intended purpose, i.e. to prevent a state's 'dalliance or unreasonable delay,'" FERC said.



Map shows facilities in a portion of the proposed Northern Access pipeline. | *National Fuel*

National Fuel remains "committed to the project" and intends "to request a notice to proceed from FERC once all necessary authorizations are secured," including permits from the U.S. Army Corps of Engineers, company spokeswoman Karen Merkel said.

The project faces a number of legal challenges that are currently pending in different venues. The targeted in-service date is 2022, Merkel said.

In denying the DEC and Sierra Club their motion for a stay of the waiver order, the commission said, "The movant must substantiate that irreparable injury is 'likely' to occur. The injury must be both certain and great, and it must be actual and not theoretical. Bare allegations of what is likely to occur do not suffice."

The commission also dismissed the DEC's assertion that a state environmental assessment's finding that the pipeline would have no significant impact — and a subsequent conditional certificate authority — were no longer valid given the department's denial of the water quality certification. The DEC had argued that the environmental assessment assumed the existence of certain mitigation measures, including those set out in a future water quality certification.

"On balance, the Northern Access 2016 project, if constructed and operated in accordance with the application and environmental conditions imposed by the certificate order, would not significantly affect the quality of the human environment and would be an environmentally acceptable action," the commission said. ■

PJM News

Stakeholders Tell PJM Board to Delay Capacity Auction

By Christen Smith

Stakeholders are urging PJM's Board of Managers to reschedule the upcoming capacity auction, given the growing pile of issues on which FERC has not yet ruled.

The Joint Consumer Advocates sent a *letter* April 1 advocating for a temporary delay of the Base Residual Auction currently planned for August, contending it's the best course of action to avoid possible legal and financial ramifications.

"If auctions are rerun, results refunded or other action taken, it is ultimately the end-use customers, including residential customers, who will bear those risks," the group said. "These customers are least able to hedge against those risks."

Likewise, a coalition of utility companies — including Exelon, American Municipal Power, Dominion Energy, EDP Renewables, Avangrid, NextEra Energy Resources, Public Service Enterprise Group and Talen Energy Marketing — said delaying the auction until April 2020 guaranteed the most time for stakeholders to adapt to any market rule changes handed down by FERC in the coming year. Seven dockets remain outstanding, the companies pointed out.

"By all public accounts, commission action does not appear imminent," the utilities said in their March 29 *letter* to the board. "Given this inaction, the same concerns that led PJM to reschedule the 2022/23 BRA last August apply with equal force now. If anything, the need for clarity on auction scheduling is more severe now than it was last fall."

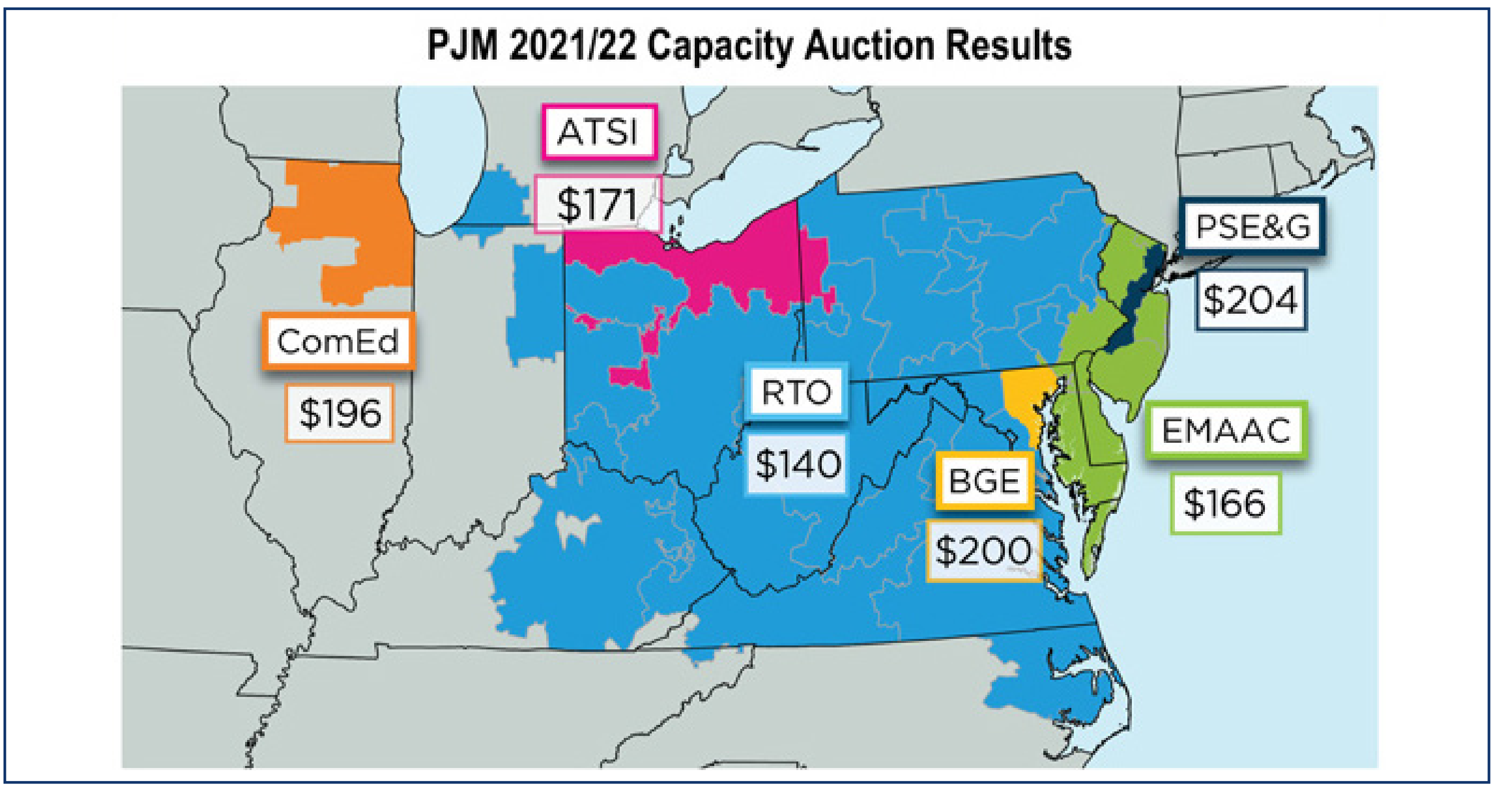
The letters come a week after PJM staff presented the Markets and Reliability Committee with four options for the August BRA, including do nothing and run the auction under current rules; file a delay waiver; file a request to confirm existing rules for the interim; or propose an interim rate. Each option came with considerable drawbacks, PJM's Stu Bresler said during a March 21 MRC meeting. (See *PJM Mulls Options for August Capacity Auction*.)

It could be the second time PJM decides to delay the BRA after a June 2018 FERC ruling determined its minimum offer price rule (MOPR) was unjust and unreasonable. The RTO proposed a new rate in October and had hoped for a ruling from the commission by March 15 to no avail. (See *PJM to FERC: Hurry Up with Auction Guidance*.)

Although the utility companies want a delay of eight months — just six weeks before the regularly scheduled May 2020 BRA — consumer advocates want the briefest postponement possible, noting the competing interests of market participants, state utility commissions, legislatures and stakeholders.

"In that [first] waiver request, PJM stated that rescheduling the 2022/23 BRA was appropriate to allow stakeholders, PJM and FERC time to develop and establish appropriate replacement rules within a time frame that allows for the conduct of the BRA in an orderly manner," the advocates said in their letter. "It is important that the PJM board not lose sight of these goals. PJM's capacity market represents a large portion of the costs passed along to residential customers throughout the PJM footprint. Uncertainty in market rules and the permanence of market results can increase bids, which in turn increases costs."

Bresler said PJM staff will reveal their decision for the auction at the April 10 meeting of the Market Implementation Committee. ■



| PJM

PJM News

Judge Rejects Liability Release in FirstEnergy Reorg

Continued from page 1

statement released after the hearing.

Attorneys representing EPA, the Nuclear Regulatory Commission and other agencies weighed into the case aggressively in recent weeks saying FES lawyers had ignored them.

They made it clear they consider FirstEnergy responsible for power plant environmental damages and labeled the reorganization plan a "scheme."

Koschik initially was not certain the bankruptcy court had the broad powers ascribed to it by FES attorneys to protect the parent company far into the future.

Complicating the situation was the court's approval of a settlement FirstEnergy and FES negotiated last summer, with the concurrence of the major creditors. In exchange for indemnity, FirstEnergy agreed to pay FES $600 million in cash and about $400 in services and limited guarantees.

While the judge approved that settlement, separating the two companies, he explained since then he did not approve the details absolving FirstEnergy from future claims for environmental damage.

But in the months following that September 2018 court ruling, FirstEnergy ballyhooed the approval as proof it would now be profitable as a fully regulated, delivery-only company. That news helped push FirstEnergy's share price to a high of $42.13 in the last 52 weeks.

The stock tumbled more than 4% Thursday afternoon, closing at $39.44 on the New York Stock Exchange.

In filings late last month, opponents said approval of the proposed restructuring would make it difficult or impossible to file claims against FirstEnergy over coal ash or nuclear contamination.

The OCC argued that, under the proposed reorganization, "FirstEnergy would be shielded from any claims or causes of action related in any way to the debtors' businesses and property, including from any liability for the costly decommissioning of its power plants."

"Were funds for decommissioning to be inadequate, for example, consumers or taxpayers might be (unfairly) called upon to fund FirstEnergy and FES' power plant decommissioning liabilities to federal and state governments," the OCC said. ■

FirstEnergy's Akron, Ohio, headquarters

PJM News

Argonne to Join PJM DER Integration Effort

By Christen Smith

| Cubit Power Systems

The U.S. Department of Energy's Argonne National Laboratory will collaborate with PJM to develop standards aimed at improving the integration of distributed energy resources onto the grid, the RTO announced last week.

Under a new Cooperative Research and Development Agreement, Argonne will partner with PJM's Distributed Energy Resource Ride-Through Task Force to study ride-through and trip guidelines from the Institute of Electrical and Electronics Engineers (IEEE) and adjust those rules to better serve the RTO's growing share of rooftop solar energy resources.

"Our primary mission is reliability, and we are preparing our system for the advent of more distributed energy resources so that we can seamlessly operate and understand DER behavior, both during normal operations and times of system stress," *said* Chantal Hendrzak, executive director of applied innovation and market evolution for PJM.

"Our team has directly relevant experience in modeling and usage of simulation tools, and it has conducted similar analyses for the DOE and the North American Electric Reliability Corp. that can contribute to this joint effort," said Ning Kang, an Argonne staff scientist who is leading the project with PJM.

The lab also sent Rojan Bhattarai to work on site with the task force. He will analyze regional data, develop power system models with DERs and help RTO stakeholders fine-tune DER operational settings to maintain optimum system reliability.

Before the widespread adoption of DERs, the grid was designed to handle one-way power flows, with energy moving from generating plants through the transmission system, before being stepped down to the distribution system and ultimately transmitted to end-use consumers. The growing volume generation coming off the distribution network is forcing grid operators to rethink the system to accommodate unconventional flows.

PJM said DERs — including solar, battery storage, combined heat and power plants and some wind turbines — currently function on settings designed to respond to unexpected system malfunctions that disrupt power flow. Some sources "ride-through" the event, providing much-needed reliability, while others "trip-off" to prevent system damage. Solar panels and other DERs also can't tell the difference between a transmission fault and a distribution fault, causing inappropriate responses and overstressing the system.

"For transmission system faults, DERs should stay connected to maintain reliability, while for distribution system faults, DERs should stop producing as fast as possible to ensure safety and protection," Bhattarai said.

But there's a key problem: DERs can't detect where a fault occurred.

"So the challenge for PJM and others is to find a middle ground and come up with one set of operating rules that can ensure DERs function properly for faults on both the transmission and distribution side."

IEEE last year updated its standard for voluntary DER interconnection (IEEE 1574-2018), which informs trip and ride-through settings but — as PJM acknowledges — "offers a fair amount of leeway," leading utilities to implement different required settings.

"The combined PJM-Argonne team will study the impact of DER trip and ride-through timing in the current IEEE standard to help PJM stakeholders reach a consensus on DER integration," the RTO said. "It will also inform the technical guidance that utilities and states can use to implement DERs across the region PJM serves." ■

PJM News

Critics Warn Pa. Lawmakers Against Nuke Subsidy Bill

By Christen Smith


Todd Snitchler

HARRISBURG, Pa. — Critics of a bill to subsidize Pennsylvania's failing nuclear fleet on Monday advised state lawmakers to put the brakes on the proposal, saying it would distort the deregulated energy markets it worked long to build.


Glen Thomas

Glen Thomas, president of GT Power Group, testified before the House Consumer Affairs Committee that House Bill 11 upends two decades of regulatory and legislative work and wastes $12 billion in stranded costs spent transitioning to a competitive wholesale power marketplace.

"It's an absolute competition killer," he said. "It's a big deal. It's a very complicated piece of legislation ... that undoes a lot of the hard work it took to get us here."

HB 11 would create a third tier of resources in the state's Alternative Energy Portfolio Standard (AEPS) program from which retail providers must purchase at least 50% of their electricity by 2021: nuclear, solar, geothermal and low-impact hydropower. The first two tiers of the legislation include 16 resource types with targets of 8% and 10%.

Prime sponsor Rep. Thomas Mehaffie (R) said the plan would provide consumer protections through capped pricing and the prevention of "double dipping" across programs. He estimated the bill would cost $500 million — one-eighth of the $4.6 billion in annual costs he claims would result should all five nuclear plants in the state shut down: $788 million in higher electric prices; $2 billion in lost GDP; and $1.86 billion in costs associated with carbon emissions and harmful criteria air pollutants, including SO_2, NO_x and particulate matter. (See *Pa. Lawmakers Unveil $500M Nuke Subsidy Bill*.)

Exelon will begin the four-month process of shutting down Three Mile Island near Harrisburg in June if lawmakers fail to act. FirstEnergy will retire Beaver Valley in 2021 in what the company described as a growing trend during its testimony before the committee on Monday.

"On one hand, emitting plants get to pollute for free, not bearing any of the cost of the pollution they put into the air or water," said Dave Griffing, vice president of government affairs for FirstEnergy Solutions. "And on the other hand, 16 other forms of technology get a payment, some as high as $55[/MWh], from the federal and state government through tax credits and AEPS credits. The result is not shocking. Pennsylvania nuclear facilities and others across the country have their hands tied behind their backs and are facing early retirement."


Dave Griffing

Critics of the plan argue there's better, cheaper ways to reduce carbon emissions and insist that subsidizing nearly 70% of the market props up aging nuclear reactors at the expense of competition.

"This is a major shift in Pennsylvania's energy policy from a policy that puts consumers in the driver's seat to one that puts policymakers in the driver's seats by dictating where their energy comes from," Thomas said, noting he's spent the majority of the last 15 years convincing other states to deregulate their energy markets like Pennsylvania has. "HB 11 puts the thumb on the scale for 68% of the delivered megawatts in this state if approved."


Tom Ridge

Tom Ridge, former secretary of Homeland Security and Pennsylvania governor from 1995 to 2001, said preserving the state's five nuclear facilities maintains reliability. He signed the 1996 bill deregulating the state's energy markets and allowing it to join PJM.

"I've always believed in a diversified portfolio," he told lawmakers Monday. "We want competitive markets and competitive markets need multiple sources of generation. Other states are doing it because they can't wait on the feds to do it. In five or six years, we may not have these facilities left."

Todd Snitchler, vice president of market development for the American Petroleum Institute, said PJM's generation portfolio will remain balanced, even as trends shift away from nuclear energy. Last month, the Independent Market Monitor said gas-fired energy output exceeded coal in PJM last year for the first time, though sources remain relatively balanced among gas (30.9%), coal (28.6%) and nuclear (34.2%), with renewables accounting for a small but growing share of less than 3%.

"A concern about a dash to gas needs to be tempered by realities on the ground," he said.

The committee will host a second public hearing on HB 11 in Harrisburg on April 15.

The Senate version of the bill, SB 510, was introduced last week by Sen. Ryan Aument (R). That bill differs from the House version in that it directs the state's Public Utility Commission to set credit prices and guarantee that between 17 and 23% of Tier III sources purchased include non-nuclear suppliers, like wind and solar. (See related story, *Pa. Lawmakers Introduce 2nd Nuke Subsidy Bill*.) ■

PJM News

Pa. Lawmakers Introduce 2nd Nuke Subsidy Bill

By Christen Smith

Pennsylvania lawmakers proposed another $500 million plan to subsidize the state's nuclear industry and characterized as politically motivated ongoing criticisms that the effort represents a corporate bailout.

State Sen. Ryan Aument (R) introduced Senate Bill 510 on Wednesday, more than three weeks after a similar House of Representatives bill, HB 11, drew reproach for its perceived prioritizing of aging, expensive nuclear reactors over cleaner, cheaper forms of energy. (See *Lawmakers Unveil $500M Nuke Subsidy Bill*.) Nuclear generation supplied about 42% of Pennsylvania's net generation in 2017, compared with 4.5% for renewables, according to the Energy Information Administration.

"Powerful special interests have disingenuously branded any support for the nuclear industry as a 'bailout,' but in reality, current law stacks the deck heavily against Pennsylvania's nuclear plants," Aument *said*. "Including nuclear energy in the state's alternative energy plans will help level the playing field for the industry and ensure its long-term viability in Pennsylvania's marketplace while simultaneously protecting ratepayers from higher electricity bills down the road."

Like its House companion, SB 510 creates a third tier within the state's Alternative Energy Portfolio Standard (AEPS) program, from which suppliers must buy 50% of their power by 2021. Unlike the House version, however, the Senate bill directs the Public Utility Commission to set credit prices and guarantee between 17 and 23% of Tier III sources purchased include non-nuclear suppliers, like wind and solar. The first two tiers of the AEPS include 16 renewable resource types with targets of 8% and 10%, respectively.

"Nuclear energy is the most efficient, carbon-free producer in our system," Aument said. "The loss of Pennsylvania's nuclear industry will inevitably lead to increased costs for ratepayers, a less reliable and resilient electricity grid, and a loss of billions of dollars for the state's economy."

Also like HB 11, SB 510 looks to offset an estimated $4.6 billion in annual costs proponents claim would result from all five nuclear plants in the state shutting down: $788 million in higher electric prices; $2 billion in lost state GDP; and $1.86 billion in costs associated with carbon emissions and harmful criteria air pollutants, including SO_2, NO_X and particulate matter.

Exelon said it will begin the four-month process of closing Three Mile Island near Harrisburg in June if legislators don't act. FirstEnergy has also scheduled Beaver Valley for early retirement effective 2021.

"Making long-term energy decisions based exclusively on short-term marginal cost would be foolish," Aument said. "Far too often, Harrisburg is short-sighted and kicks the can down the road when faced with difficult economic choices. We have an opportunity now to do the right thing for ratepayers by preserving the role of the nuclear industry and avoid repeating the painful and expensive mistakes of the past."

An analysis from ClearView Energy Partners determined the expanded carve-outs for non-nuclear resources in Tier III mean some of the state's struggling reactors could still be priced out of the market. Both proposals require the PUC to rank resources based on environmental benefits, meaning low-generating reactors like TMI could be considered the "least beneficial" to operate, given SB 510's additional targets in the third tier.

Three Mile Island

Skeptics Unsatisfied

Ryan Boop, Aument's chief of staff, told the senator would not introduce a bill unless he was comfortable with the language.

"As such, we were very methodical in the drafting of SB 510 and took input from all six [Senate co-sponsors] and their staff members," Boop said. "As a group, we sought feedback from the Public Utility Commission and various other sources. I think many of the differences in the two bills can be attributed to the additional time we had to draft the language and the additional input we received from the PUC and those other sources."

But the modifications haven't engendered any good will from the bill's critics. Steve Kratz, spokesman for Citizens Against Nuclear Bailouts — a coalition of power generators and energy, business and manufacturing associations — characterized the long-awaited proposal as "disastrous." He argued similar legislation in New York drove 99% of taxpayer funding for the program in 2017 directly into Exelon's coffers.

"The 'consumer protections' and additional carve-out for renewables touted by the bill sponsors [are] a disingenuous attempt to distract away from the fact that this bill will irreversibly alter electric competition and force consumers to pay higher bills to benefit the special interests of Exelon, FirstEnergy Solutions and Talen Energy and shareholders," he said.

PJM's Independent Market Monitor said last month three of the RTO's 18 nuclear facilities face revenue shortfalls through 2021, a natural reaction to competition. The three plants — Davis-Besse, Perry and TMI — each operate just one reactor, which is the source of their financial strain, the Monitor said. The remaining multiunit facilities, including the subsidized Quad Cities in Illinois, will remain profitable. Even without zero-emission credits, Quad Cities would cover its costs for the next three years, according to the Monitor. (See *Monitor Says PJM's Capacity Market not Competitive*.)

The House Consumer Affairs Committee kicked off four weeks of hearings on HB 11 on Monday. (See related story, *Critics Warn Pa. Lawmakers Against Nuke Subsidy Bill*) It's unclear when the Senate will schedule meetings to discuss Aument's bill, though it could come later this month. ■

SPP

SPP Solicits Interest in Western Real-time Market

By Tom Kleckner

SPP has cast a longing, yet casual, eye at Western markets for some time.

On Thursday, the Arkansas-based RTO made its long-held interest in the West official by "calling on interested utilities and other customers" to help build a real-time market "that will meet the electricity needs of the Western Interconnection."

"We're still a long way off from building anything," SPP spokesman Derek Wingfield told *RTO Insider*. "We're looking for people interested in an SPP market."

Wingfield said the RTO, which has a footprint that stretches from Louisiana across the Great Plains to the Canadian border, has long had "casual conversations with some in the West" about the possibility of an SPP-designed market. Market services would be provided on a contract basis, allowing participants to maintain their independence from an RTO, Wingfield said.

SPP's market would provide an alternative to CAISO's Western Energy Imbalance Market, which was established in 2014 with the six-state PacifiCorp system as its first member.

CAISO announced Wednesday it had added its first publicly owned utility in the Sacramento Municipal Utility District and says its market has saved members nearly $565 million since it started. (See related story, *SMUD Goes Live in Western EIM*.)

SPP did not offer a timeline for its own imbalance market, saying once it found entities interested in market services, it would scope out the market's needs before talking benefits and timelines.

Carl Monroe | © *RTO Insider*

"There seems to be growing interest in organized markets in the West, and SPP believes we're uniquely equipped to provide service and benefits no one else can," COO Carl Monroe said in a *statement*.

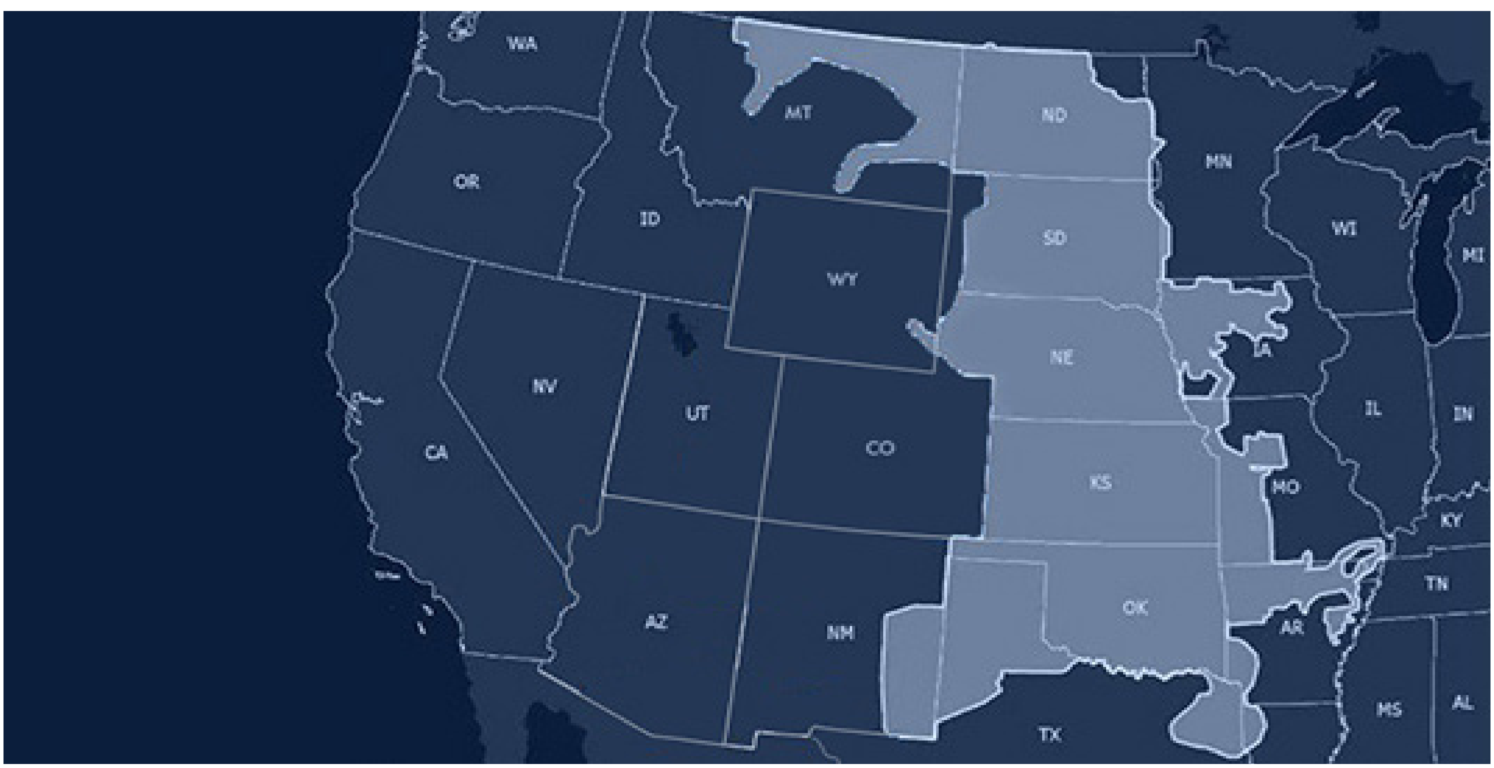
Monroe would know. He has always been open to discussions with entities interested in joining markets, and he led SPP's recent effort to absorb the Mountain West Transmission Group, an informal collaboration of 10 electricity service providers in the Rocky Mountains. That effort fell apart last spring, but it gave SPP a deeper insight into the Western Interconnection's market needs. (See *Mountain West, SPP Tout RTO Membership to Colo. PUC*.)

In December, SPP will also become the reliability coordinator (RC) for more than a dozen Western entities. The RTO has been working closely with its new customers, future neighboring RCs and regulatory bodies to finalize the governance and operations plans for RC services.

"SPP understands Western utilities' system needs and approach to business," CEO Nick Brown said. "Utilities have the daunting task of ensuring electric reliability and affordability for their customers. It's been our experience that energy imbalance markets are a wonderful way to accomplish that."

The RTO said its day-ahead market has provided participants more than $2.7 billion in savings since it launched in 2014, and it noted it has provided various services to "dozens of nonmember organizations" on a contract basis.

"SPP has experience not only building and administering electricity markets but specifically doing it to meet the needs of a diverse group of customers," Monroe said. ■



| SPP

SPP

SPP Seams Steering Committee Briefs

SPP, MISO Agree to Move Ahead with Joint Study Plan

The SPP-MISO Joint Planning Committee has voted to begin a new coordinated system plan (CSP) this year, SPP staff told the RTO's Seams Steering Committee last week.

The JPC, composed of planning staff from both RTOs, conducted the vote in March. The CSP is the first step in determining whether to build transmission projects that address interregional needs.

SPP Interregional Coordinator Adam Bell told the SSC during its Wednesday meeting that the RTOs' planning staffs are exchanging solutions submitted through their regional processes for the CSP "joint" needs. Staff are also finalizing a draft CSP study scope, he said.

The RTOs have not yet scheduled a meeting to share initial results with stakeholders, but they have identified six potential economic projects along the seam. (See *MISO, SPP Seek Coordinated Plan in 2019*.)

"We've identified modeling inconsistencies, but our models are always going to be different," Bell said. "Once we posted the needs, that's when both sides began looking into the models."

The study could result in a first-ever interregional transmission project for the RTOs, which conducted CSP and regional reviews in 2014 and 2016. They were unable to reach an agreement on interregional projects both times.

Switchable Generation Plan with ERCOT Almost Complete

Staff told the committee that SPP will be executing a coordination agreement with ERCOT for switchable generation resources (SWGRs) shortly. (See "ERCOT, SPP, MISO Hammer out Coordination Plans," *ERCOT Board of Directors Meeting: Feb. 12, 2019*.)

The grid operators have been working since 2016 on a new agreement to cover the four resources capable of switching between SPP and ERCOT. The plan applies only to the operations of the reliability coordinators and does not address financial obligations of the SWGRs directed to switch in emergency conditions, RTO staff said.

SPP's Market Working Group will be responsible for developing new commitment statuses and a mechanism to uplift financial obligations of SWGRs instructed to switch to SPP from ERCOT.

Two of the resources belong to Golden Spread Electric Cooperative and have historically operated in SPP. The other two resources belong to Tenaska and operate in ERCOT.

M2M Payments Soar to $3.33M in February

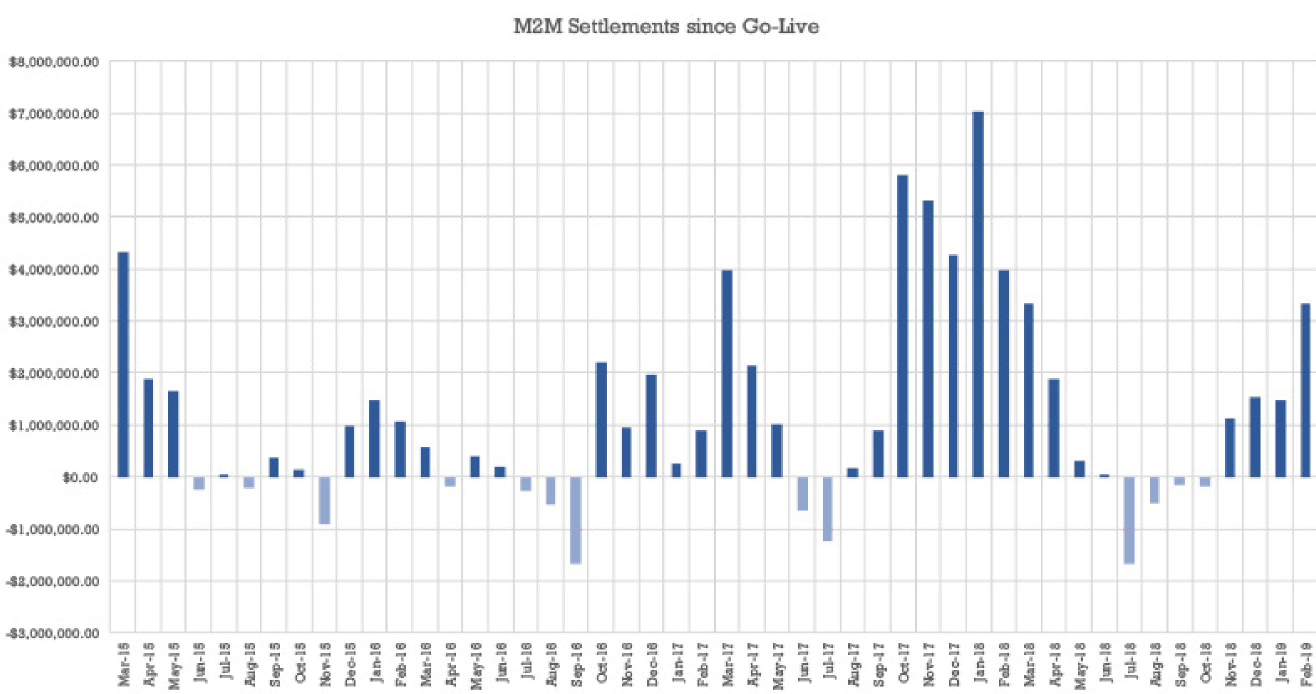
SPP recorded $3.33 million in market-to-market (M2M) payments from MISO in February, the highest amount since last March and the ninth-highest since the two RTOs began the process in March 2015.

February also marked the 23rd month in the last 29 in which M2M distributions have flowed in SPP's direction. SPP has now amassed $58.6 million in net payments from MISO.

Permanent flowgates along the SPP-MISO seam were binding for 244 hours, and temporary flowgates were binding for 245 hours. That resulted in $1.98 million and $1.35 million in payments, respectively.

Casey Cathey, SPP's manager of reliability planning and seams, told the SSC that staff hope to discuss with MISO potential changes to the M2M process. "My personal view is to optimize the system for congestion, rather than this clunky process," he said. ■

— Tom Kleckner



Note: Positive values are payments to SPP from MISO; negative values are payments from SPP to MISO.

| SPP

Company Briefs

Citing Climate Differences, Shell Walks away from Refining Lobby

Royal Dutch Shell became the first major oil and gas company to announce intentions to leave the American Fuel & Petrochemical Manufacturers by 2020 over a disagreement on climate policies.

Shell said it found "material misalignment" over climate policies and intends to keep its promise to increase transparency and to stay in line with the 2015 Paris Agreement's goals to reduce carbon emissions to net zero by the end of the century.

"The need for urgent action in response to climate change has become ever more obvious since the signing of the Paris Agreement in 2015. As a result, society's expectations in this area have changed, and Shell's views have also evolved," CEO Ben van Beurden said.

More: *Reuters*

Vineyard Wind Commits to Fisheries Monitoring

Vineyard Wind said it will adopt research measures to monitor the effects its 84-turbine offshore wind farm has on fisheries.

Vineyard, which hopes to begin construction later this year of a wind farm south of Martha's Vineyard, partnered with the University of Massachusetts Dartmouth's School for Marine Science and Technology in 2017 to research a method for monitoring the effects on fisheries. As part of the company's agreement with UMassD, the school will conduct the studies later this spring.

More: *Cape Cod Times*

Former SCANA Execs to Face Fraud Charges in Court

U.S. District Court Judge Margaret Seymour ruled that enough evidence exists to show a jury that former SCANA executives deliberately concealed the unstable status of their doomed V.C. Summer nuclear power plant project from investors. The ruling allows a civil fraud lawsuit by former company shareholders to move forward to a future jury trial where shareholders are seeking to recover roughly $2.7 billion in alleged losses to their stock holdings.

The lawsuit alleges that SCANA made deceptive statements about the health of the project to artificially pump up the company's stock price. Then, when the project failed, SCANA's stock price plummeted to $43/share (down from $72), in which shareholders say they lost about $2.7 billion.

At a March 4 hearing, lawyers for the former SCANA officials argued that the shareholders' lawsuit should be dismissed because of a lack of evidence and that the officials told investors the truth and disclosed risks.

More: *The State*

Federal Briefs

Reuters: US Sets Sights on China in New EV Push

U.S. government officials plan to meet with executives from automakers and lithium miners in early May as part of a first-of-its-kind effort to launch a national electric vehicle supply chain strategy, three sources familiar with the matter told Reuters last week. While Volkswagen, Tesla and other electric-focused automakers and battery manufacturers are expanding in the U.S. and investing billions in the new technology, they are reliant on mineral imports without a major push to develop more domestic mines and processing facilities. China dominates the global EV supply chain.

As part of the effort, Sens. Joe Manchin (D-W.Va.), **Shelley Moore Capito** (R-W.Va.) and Lisa Murkowski (R-Alaska) last week reintroduced the Rare Earth Element Advanced Coal Technologies Act (REEACT), which would allow for the development of technology capable of extracting rare earth elements from coal and coal byproducts to re-establish a U.S.-based supply chain. The bill was first introduced in the Congress in July 2017, and the Senate Energy and Natural Resources Committee advanced it to the floor in March 2018, but it went no further.

"Rare earth elements are essential to our economy and national security, but the United States is currently dependent on foreign suppliers — particularly China — for this valuable resource," Capito said. "This legislation would help support the research and development of these technologies, a win-win-win for Appalachia's economy, the environment and our national defense."

More: *Reuters*; *Senate ENR Committee*

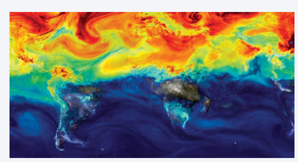
House E&C Passes Resolution Blocking Paris Withdrawal

On a 29-19 party-line vote, the House Energy and Commerce Committee last week advanced a binding resolution that would commit the U.S. to remaining in the Paris Agreement on climate change.

Republicans on the committee complained that Democrats leapfrogged a subcommittee markup and a hearing for the measure to expedite its approval. The bill now heads to the Foreign Affairs Committee.

More: *Politico*; *The Hill*

Study: CO2 Levels at Highest Level in 3M Years



Researchers at the Potsdam Institute for Climate Impact Research in Germany last week published a study that found that there is more CO_2 in our atmosphere today than in the past 3 million years.

The amount of CO_2 in the atmosphere today is "unnatural," lead-author Matteo Willeit told CNN. He added that global mean temperatures are rising much faster than any time since the Pliocene epoch, the geological period 2.6 million to 5.3 million years ago.

During the Pliocene, sea levels were as much as 65 feet higher than they are now, Greenland was mostly green and Antarctica had trees. Humanity's ancestors began to walk upright during this era.

More: *CNN*; *USA TODAY*

State Briefs

ARIZONA

Tucson Electric Proposes Rate Increase

Tucson Electric Power is seeking to increase customers' monthly bill by an estimated $7.61/month, saying it needs higher rates to pay for system improvements. If approved, the increased would go into effect in May 2020.

TEP said its proposal, filed with the Corporation Commission last week, includes a $2 increase in the basic monthly charge. The company also said its current rates do not reflect about $1.2 billion it has invested to maintain and improve service since June 2015.

The company said the new rates support the installation of natural gas burning reciprocating internal combustion engines to provide peak power at the H. Wilson Sundt Generating Station and reflect the cost of the purchase of a second unit at the gas-fired Gila River Generating Station.

More: *Arizona Daily Star*

APS Acknowledges Spending Millions to Elect ACC Members

Arizona Public Service, along with its parent company Pinnacle West Capital, admitted it donated millions to "dark-money political groups" in 2014 that helped elect two candidates to the Corporation Commission. The two disclosed the information following a request from regulators, including a subpoena from one regulator elected to replace a commissioner APS helped into office.

The 453-page document showed that in 2014, Pinnacle West gave $12.9 million to 16 different political groups, with $10.7 million going to groups that contributed to commissioner elections that year.

More: *Arizona Republic*

MAINE

Mills Signs Bill Preserving Net Metering

Gov. **Janet Mills** signed a bill last week that allows homeowners to continue receiving credits on their electricity bills for the excess solar energy they generate and feed to the grid. By signing the bill, Mills ended both the planned phase-out of the credit system for excess solar energy and a related requirement that made utilities install a second meter on homes with solar energy systems.

L.D. 91, the bill that would repeal the requirement that solar-powered homes and businesses have a second meter installed to monitor the output of solar panels, drew comparisons to "allowing grocery stores to charge for fruits and vegetables grown in home gardens."

"For too long, Maine has lagged behind other states in embracing policies that advance the future of solar power," Mills said. "That ends today. By signing into law this bill, we are restoring net metering, resetting Maine's solar policy, and charting the course for the growth of solar power to lower electricity bills and combat climate change."

More: *Portland Press Herald*

MISSOURI

Bill Would Bar Eminent Domain for Grain Belt Express

A House panel advanced legislation that would prohibit the use of eminent domain to acquire easements for the proposed 750-mile Grain Belt Express project.

The $2.3 billion project has been repeatedly delayed by regulatory hurdles and court battles. The Public Service Commission's certificate of convenience and necessity, granted last month, deems it a public utility, which allows it to pursue condemnation cases in local courts against landowners who refuse to sell easements. This legislation is intended to block that and force the power line to zig zag around unwilling sellers.

The PSC had concluded that "the broad economic, environmental and other benefits of the project ... outweigh the interests of the individual landowners."

More: *The Associated Press*

MONTANA

Solar Businesses Win Lawsuit Against PSC, NorthWestern

State Judge James Manley last week sided with the solar developers in a lawsuit faulting NorthWestern Energy and the Public Service Commission for thwarting small renewable energy projects.

Manley blamed the PSC for deliberately creating contract and pricing terms that made solar projects uneconomical. The commission has 20 days from the date of the ruling to come up with a fair pricing scheme and to restore solar energy contracts to 25 years. For NorthWestern, the ruling means the utility will have to start offering 25-year contracts to solar developers at a price reset by the PSC.

Commissioners knew their actions would kill solar development, Manley said. In a 2017 conversation recorded by a hot mic, Commissioner Bob Lake acknowledged to PSC staff that cuts made that morning to rates and contracts offered to small renewable energy projects were deep enough to kill future development.

More: *Billings Gazette*