RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2019/Issue 28 July 16, 2019

FERC Staff Hear Doubts on ISO-NE Fuel Security Plan

Regulators, Stakeholders Seek Delay in Schedule

By Michael Kuser and Rich Heidorn Jr.

FERC staff heard state regulators and NEPOOL members weigh in on ISO-NE's proposed winter energy security improvements Monday. | © *RTO Insider*

WASHINGTON — New England regulators and stakeholders told FERC on Monday they fear ISO-NE's fuel security proposal could increase costs without solving the region's winter supply concerns, urging the commission to postpone the RTO's Oct. 15 filing deadline and require it to provide more analysis before drafting Tariff changes.

Matthew Nelson, Massachusetts DPU

The "ISO, to its credit, has done a lot of hard work in a short amount of time," Matthew Nelson, chairman of the Massachusetts Department of Public Utilities, told FERC staff during a daylong public meeting (*EL18-182*, et. al.). "But … this is a case of too much, too fast."

"We don't want to buy things we don't need to buy," said New Hampshire Public Utilities Commissioner Kathryn Bailey, who said the proposal could increase the region's already high electric rates. "The current design suggests that we have a winter problem, but we're going to pay for ancillary services year-round."

Continued on page 17

ISO-NE Tweaks Inputs for FCA 14 Fuel Security Analysis (p.19)

An End to GOP 'Science Debate' on Climate Change?

By Rich Heidorn Jr.

WASHINGTON — Tom Hassenboehler used to work for Sen. James Inhofe, the Oklahoma Republican who famously brought a *snowball* to the floor of the Senate in 2015 to make the case that the Earth couldn't be warming.

Has the level of debate improved since then?

Yes, said Hassenboehler, former chief counsel for energy and environment at the House Energy and Commerce Committee, noting his last bosses in Congress were Reps. Greg Walden (R-Ore.) and Fred Upton (R-Mich.).

"They started off [2019] in hearings with the Democrats … acknowledging climate [change] is real and not wanting to have a science debate anymore and … focusing on what is the solution now," said Hassenboehler, now with *The Coefficient Group*. "While it may seem small to some folks, I think it is a big step. … Republicans have to be on the same side — of figuring out what their solution is."

Republican Colin Hayes, former staff director at the Senate Energy and Natural Resources Committee, also sees a change. "The shift in rhetoric is usually a leading indicator of policy change," said Hayes, co-founder of lobbying firm *Lot Sixteen*. "And then it's a conversation about the policy prescription and what it takes to get the requisite number of 'yes' votes to make an actual change. That conversation is underway now in a more energized away than it has been."

Travis Kavulla, R Street Institute | © *RTO Insider*

Hassenboehler and Hayes spoke July 9 on an energy policy panel moderated by former Montana regulator Travis Kavulla, now

Continued on page 6

Also in this issue:

ERO Insider

ERO Insider's website is now live! And for a limited time, access is free. Here are just a few of the stories we published this week:

No Breakthrough Seen on FR Measurements

House Energy Hearing on cybersecurity

Check it out at *www.ero-insider.com*

10837 Deborah Drive ▣ Potomac, MD 20854 ▣ (301) 299-0375 ▣ info@rtoinsider.com ▣ www.rtoinsider.com ▣

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Art Director
Mitchell Parizer 718-613-9388

Associate Editor / D.C. Correspondent
Michael Brooks 301-922-7687

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Christen Smith 717-439-1939

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Sales Director
Marge Gold 240-750-9423

Account Manager
Martha Patterson

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

2019 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,450
Newsletter PDF Plus Web	$2,000

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Counterflow

By Steve Huntoon

Scary Wrong

By Steve Huntoon

It's said the Supreme Court won't grant review to reverse a lower court decision that is "merely wrong." Don't waste the court's resources on error of little consequence.

The opposite of that we might call "scary wrong": something profoundly wrong and with significant potential consequence.

Such is the case with the Natural Resources Defense Council's new attack on PJM[1], accusing it of suppressing renewable resources relative to other RTOs, wasting billions of consumer dollars in the process and contending, in effect, that a cheap and reliable zero-carbon future could be ours if entities like PJM would just mend their evil ways.

NRDC is wrong in virtually every claim. And it's scary because policy based on NRDC's profound errors would be profoundly misguided. We can't afford to make a bunch of mistakes in dealing with climate change.

Lies, Damned Lies and Statistics[2]

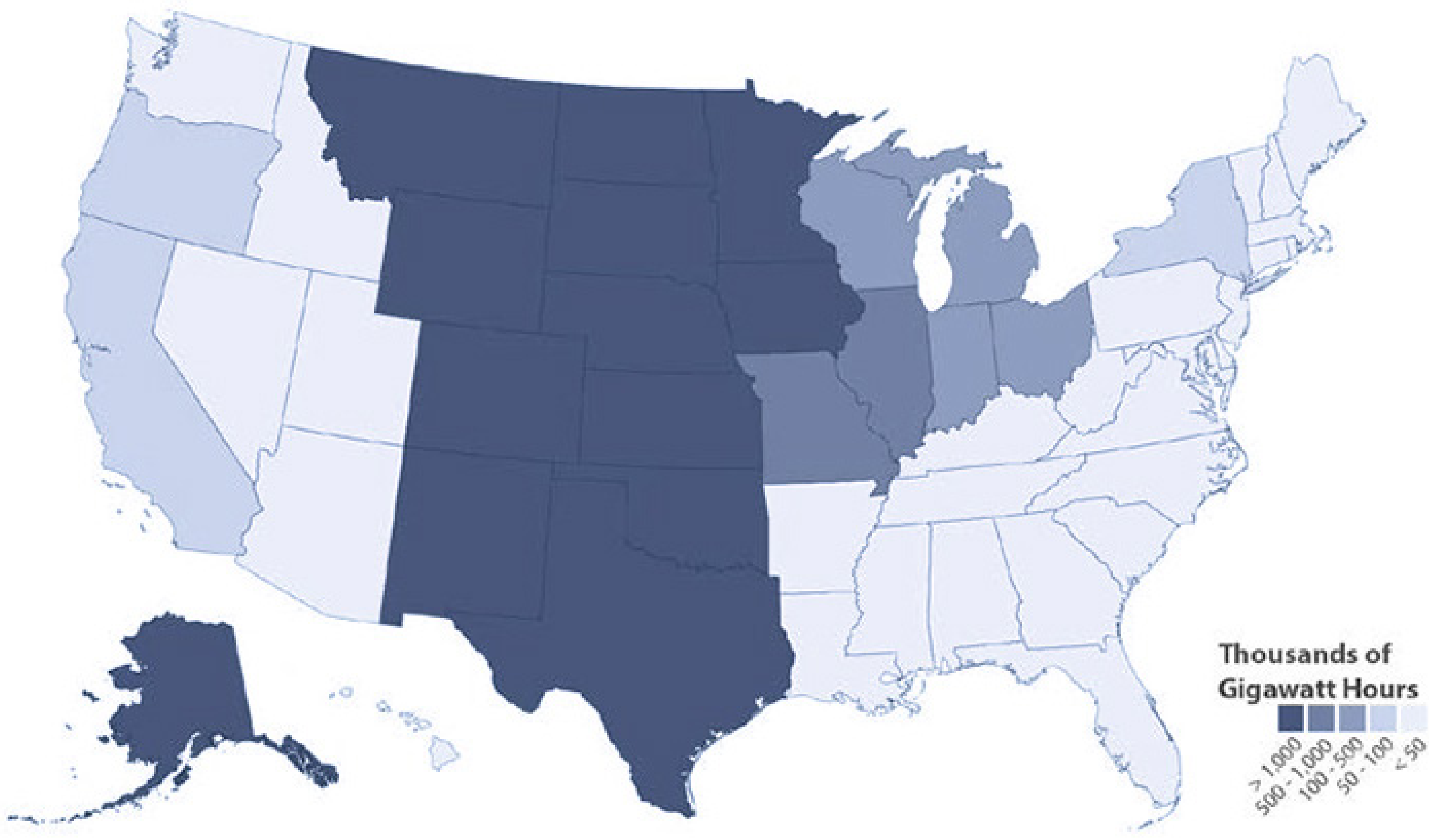
The gravamen of NRDC's attack on PJM is data it compiled showing that the RTO has added more natural gas ("polluting") resources than renewable resources since 2012. Per NRDC, other RTOs have done the reverse, adding more renewable resources than natural gas resources. NRDC points to RTOs like SPP and ERCOT as good guys.

The worst error in NRDC's attack is its complete disregard of the relative renewable resources in PJM versus SPP and ERCOT.[3]

Does this make a difference? Yes, bigly.

National Renewable Energy Laboratory and Energy Information Administration data confirm what is common knowledge in our industry that RTOs like SPP and ERCOT have *vastly* greater wind and solar potential resources. Of note, *higher* percentages of its wind and solar potential resources have been added in PJM than in either SPP or ERCOT. In other words, given the renewable cards it was dealt, PJM (or more accurately the PJM region) is doing a better job.

To show this, we'll use NREL data by state on the "technical potential" of renewable resources, which reflects among other things environmental and land-use constraints. (This is important because a wind project isn't going to be built in Philadelphia.) Let's start with wind (because existing wind gigawatts are several times larger than existing solar gigawatts in the U.S. overall, and many times larger in the states



SPP has 26 times as much wind potential as PJM, while ERCOT has nine times as much. | *National Renewable Energy Laboratory*

Counterflow

By Steve Huntoon

comprising PJM, SPP and ERCOT).

NREL data show that PJM has around 165 GW of potential onshore wind capacity, in contrast to SPP's 4,235 GW and ERCOT's 1,426 GW.[4] This means SPP has 26 times more potential wind than PJM; ERCOT has nine times more potential wind than PJM.

How much wind has been added so far in these RTOs? PJM has 9,428 MW of installed wind capacity,[5] SPP has 20,610 MW,[6] and ERCOT has 22,051 MW.[7]

So which RTO has made the most of its potential wind resources? PJM has installed 5.7% of its potential, SPP has installed 0.5% of its potential, and ERCOT has installed 1.5%.[8]

Thus, given the wind resource cards it was dealt, PJM has done much better than SPP or ERCOT.

How about solar?

The NREL data show that PJM has 7,611 GW of potential utility-scale solar capacity, in contrast to SPP's 31,543 GW and ERCOT's 15,308 GW.[9] This means SPP has four times more potential solar than PJM; ERCOT has two times more potential solar than PJM.

How much solar has been added so far in these RTOs? PJM has 1,800 MW of installed solar capacity, SPP has 180 MW, and ERCOT has 1,858 MW.[10]

So which RTO has made the most of its potential solar resources? PJM has installed 0.02% of its potential, SPP has installed 0.0006% of its potential, and ERCOT has installed 0.01%.

As with wind resources, given the solar resource cards it was dealt, PJM has done much better than SPP or ERCOT.

Thus the reality: PJM has outperformed its RTO brethren in adding renewable resources given the cards it was dealt.

Stayin' Alive?

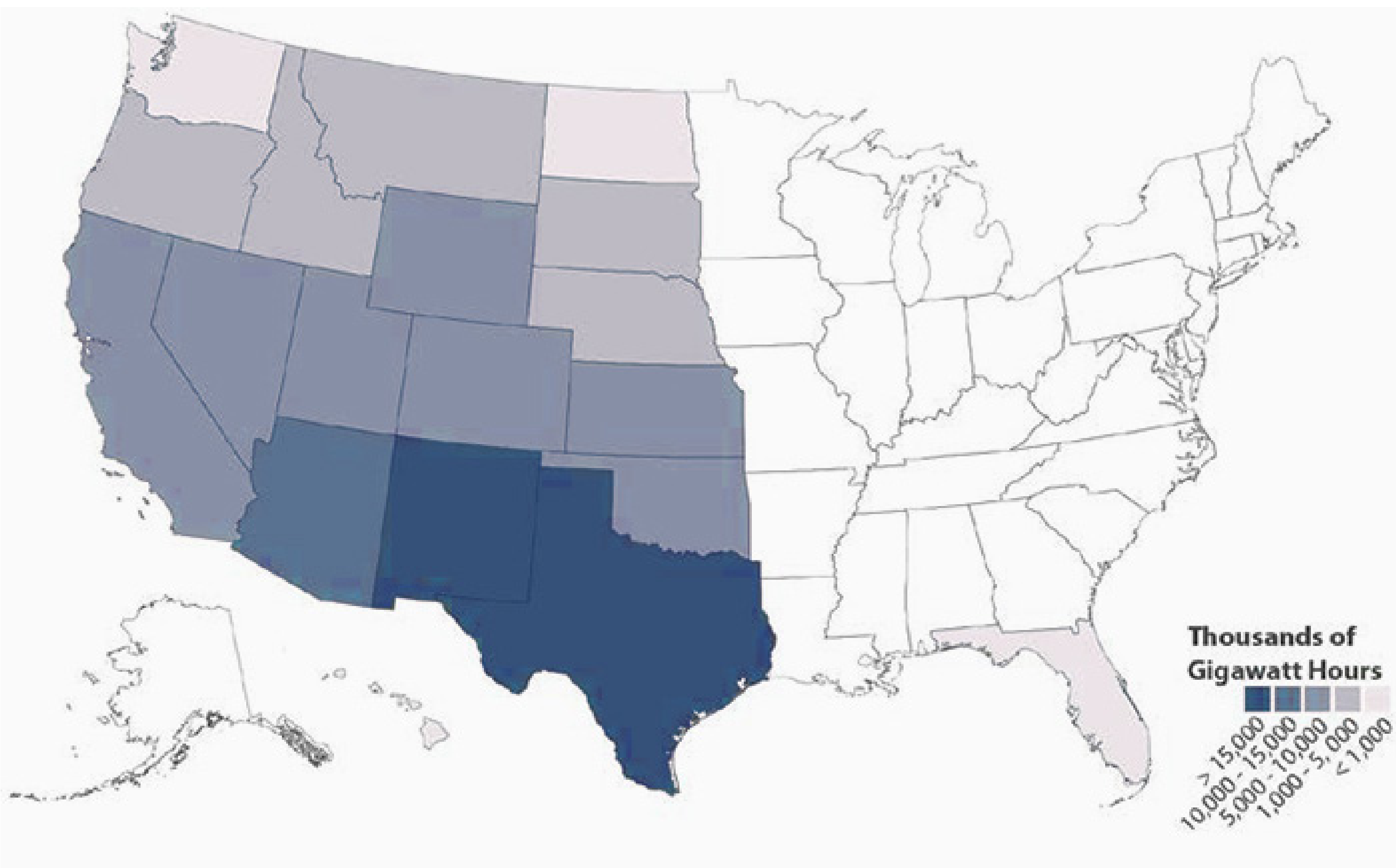
Following on its unsound narrative that PJM has done poorly in adding renewable resources, NRDC looks for a culprit. And it finds one in PJM's capacity market, which it says is "a tool for uneconomic fossil fuel power plants to get paid enough to stay alive."

This is absurd. Since the start of PJM's capacity market, an enormous 25,857 MW of coal generation in PJM has retired, which is *more than one-third of all coal generation retirements* in the entire U.S. of 70,522 MW over the same period.[11]

If PJM's capacity market is a tool to keep uneconomic coal plants alive, then it is failing miserably.

NRDC also fails to explain why (per its data) ISO-NE and NYISO have added more renewable than gas megawatts when both of those RTOs have a capacity market. How can this be, given NRDC's capacity market thesis?

The reality is that new natural gas and renewables in PJM (and elsewhere) are forcing uneconomic coal plants to retire, causing a significant reduction in carbon emissions per megawatt-hour in the RTO.[12]



SPP has four times the potential solar resources of PJM; ERCOT has twice as much. | *National Renewable Energy Laboratory*

Counterflow

By Steve Huntoon

This is what needs to continue.

And Those Extra Billions Paid by Consumers?

NRDC claims that PJM has acquired more resources in its auctions than its "target reserve," and the "extra totals up to billions of dollars more on customer bills."

This claim reflects a profound misunderstanding of PJM's capacity market. When the PJM annual auction "clears" (commits to purchase) resources above its target reserve, the clearing price for all capacity resources goes down. This greatly reduces the total cost of capacity that consumers pay.

In the last auction, for example, if resources had offered prices such that the cleared resources were equal to the target reserve, consumers would have paid $18.7 billion for capacity.[13] Instead, because resources offered more attractive prices, more resources cleared but at a much lower price, resulting in consumers paying $8.4 billion for capacity — roughly $10 billion less.[14]

NRDC has it exactly backward.

Annual Capacity Construct

NRDC says PJM has a year-round capacity requirement that hurts renewable resources for no reason. This is an amalgamation of three errors.

First, PJM in fact permits renewable resources to participate in the capacity market notwithstanding their obvious inability to be dispatchable year-round (or at all).[15] NRDC ignores this.

Second, PJM in fact permits seasonal resources to match up to simulate an annual resource.[16] NRDC ignores this.

Third, PJM basing the capacity construct on summer peak demand does not mean that PJM overbuys capacity for winter and other periods when peak demand is less. Resources need to be acquired for the overall peak, which happens to occur in the summer. Seasonal capacity variations have been considered and rejected for more than 10 years, with a PJM discussion here.[17]

If the annual capacity market was reconstructed into seasonal markets, then potentially lower prices in non-summer periods would have to be covered by higher summer prices in order to ensure resource adequacy.

There is no such thing as a free lunch.

Biting the Feeding Hand

It is ironic that NRDC targets PJM's capacity market. The capacity market has been a bulwark against bailout claims for dirty and uneconomic power plants by enabling a transition to cleaner natural gas and clean renewable generation, while assuring resource adequacy years into the future.

Fantasy and Reality

NRDC is promoting a narrative that a cheap and reliable zero-carbon future is easily ours. This narrative requires bad guys like PJM who must be obstructing an easy path forward.

Reality is different. PJM hasn't obstructed renewable resources and, in fact, is outperforming its RTO brethren given the renewable cards the region was dealt. PJM's capacity market (like other RTO capacity markets) doesn't save uneconomic coal plants, doesn't impose excessive costs on consumers, doesn't suppress renewable resources and is a bulwark against bailout claims for uneconomic coal units that should retire.

Dealing with climate change will not be cheap or easy.[18] We should get real instead of looking for fall guys. ■

---

[1] https://www.utilitydive.com/news/comparing-americas-grid-operators-on-clean-energy-progress-pjm-is-headed/557994/.

[2] First memorialized in a press account of remarks of Arthur James Balfour, 1st Earl of Balfour, in 1892, https://www.phrases.org.uk/meanings/lies-damned-lies-and-statistics.html. Another favorite: "If you torture the data long enough, it will confess to anything," a paraphrase from Ronald Coase, https://en.wikiquote.org/wiki/Ronald_Coase.

[3] NRDC mentions resource potential as one of many factors in resource development, but then proceeds to ignore it (and all other factors) in blaming PJM's capacity market, as discussed later.

[4] The NREL data are on Table 6 of its report "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," available here, https://www.nrel.gov/docs/fy12osti/51946.pdf. For states partially within an RTO, I pro-rated the potential resource by the land-area portion of the state within the RTO.

[5] https://www.pjm.com/planning/services-requests/interconnection-queues.aspx (select "In Service" status and wind as fuel).

[6] https://www.spp.org/about-us/fast-facts/ (89,999 MW total nameplate times 22.9% wind share).

[7] http://www.ercot.com/content/wcm/lists/167030/Capacity_Changes_by_Fuel_Type_Charts_May_2019.xlsx.

[8] The math is dividing the installed wind capacity for each RTO by the potential wind capacity for that RTO.

[9] Same NREL study, using Table 3 for "Rural Utility-Scale Photovoltaics by State." As with wind, for states partially within an RTO, I pro-rated the potential resource by the land-area portion of the state within the RTO.

[10] Same RTO sources as for installed wind capacity.

[11] https://www.eia.gov/electricity/data/eia860m/xls/april_generator2019.xlsx (in Retired spreadsheet, delete pre-2008 retirements, sort by Technology and then by Balancing Authority Code, add up Net Summer Capacity for PJM and for U.S.).

[12] Since 2012, when PJM began reporting CO2 lbs/MWh, they have fallen from an average of 1,092 in that year, https://www.pjm.com/-/media/library/reports-notices/special-reports/20170317-2016-emissions-report.ashx?la=en, to an average of 888 in 2018, https://www.pjm.com/-/media/library/reports-notices/special-reports/2018/2018-emissions-report.ashx?la=en. This is a reduction of 19% in six years.

[13] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-planning-period-parameters.ashx?la=en (at the Net Cost of new entry of $321.57/MW-day and corresponding target reserve margin of 159,000 MW, capacity cost would have been 159,000 MW cleared at $321.57/MW-day times 365 days (individual locational deliverability areas are ignored for simplicity)).

[14] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en (capacity cost was 163,627 MW cleared at $140/MW-day times 365 days (individual LDAs are ignored for simplicity)).

[15] Per PJM report on the auction: "1,416.7 MW of wind resources cleared the 2021/2022 BRA as compared to 887.7 MW of wind resources that cleared the 2020/2021 BRA. … The nameplate capability of wind resources that cleared in the 2021/2022 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,126 MW, which is 1,407 MW greater than the 6,719 MW of wind energy nameplate capability that cleared in last year's auction. 569.9 MW of solar resources cleared the 2021/2022 BRA as compared to 125.3 MW of solar resources that cleared the 2020/2021 BRA. … The nameplate capability of solar resources that cleared in the 2021/2022 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 1,641 MW, which is 964 MW greater than the 677 MW of solar energy nameplate capability that cleared in last year's auction." https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

[16] Per PJM report on the auction: "715.5 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. This is an increase of 317.5 MW over the 398 MW of seasonal capacity resources that cleared in an aggregated manner in the 2020/2021 BRA." Same source as preceding footnote.

[17] https://pjm.com/-/media/committees-groups/task-forces/scrstf/20160923/20160923-informational-item-pjm-response-proposal-c.ashx. Prior history is recounted here, https://pjm.com/-/media/committees-groups/task-forces/scrstf/20160525/20160525-informational-past-seasonal-initiatives.ashx.

[18] See for example this study involving the electric industry by Lawrence Makovich, https://www.hks.harvard.edu/sites/default/files/centers/mrcbg/files/78_tilting%40windmills.pdf, and this study involving the much broader Green New Deal by Benjamin Zycher, http://www.aei.org/wp-content/uploads/2019/04/RPT-The-Green-New-Deal-5.5x8.5-FINAL.pdf.

FERC/Federal News

An End to GOP 'Science Debate' on Climate Change?

Continued from page 1

director of energy policy for the R Street Institute, a "free market" think tank, at the Capitol Visitor Center.

Although the two former GOP congressional aides agreed their party is beginning to shed its climate denial, neither predicted major legislation to address the issue anytime soon.

To pass major legislation, "you need a catalyst that often times comes in the form of a crisis," said Hayes. "Constituents are just ticked off … and so they pick up their phone and call their congressman. I've never seen anything get done on the Hill, at least in the energy space, because it was a means to recognize some aspirational, more wonderful world than the one we have. It is almost always a response to people being ticked off."

Hassenboehler said Congress is responding not only to their constituents but also to Fortune 500 companies that have begun assessing their climate risks in public disclosures. "And that goes for not just tech companies, but to oil and gas and fossil companies as well."

Former congressional aides Tom Hassenboehler of The Coefficient Group, left, and Colin Hayes, of Lot Sixteen. | © RTO Insider

Lessons from the Failure of Cap and Trade

What does a solution look like?

The failure of the Waxman-Markey proposal — which cleared the House in 2009 but never received a vote in the Senate — means cap and trade is unlikely to be the centerpiece of any future legislation, Hassenboehler said.

Waxman-Markey may have failed in part because President Barack Obama decided on health care as his top legislative goal, Hassenboehler said. "But … it had more to do with the lack of compromise on the proponents' side … and their kind of one-size-fits-all solution. They didn't want to see the Senate … shape that bill in a way that was different from the Waxman-Markey proposal. … If the other side had compromised a little more, they would have gotten it done.

"It did lasting damage, frankly, to the brand of cap and trade, which is an efficient way of managing carbon pollution potentially," Hassenboehler continued. "You've got examples all across the states and in other parts of the world that have cap-and-trade programs. We don't talk about that barely at all anymore. Could that be a potential piece of the pie in the future? Sure, I still think it could come back, but it's never going to be the lead in a climate bill again in my view."

Hayes said a "forgotten" lesson of the episode was "it wasn't Republicans who killed it."

"It passed the House; it came over to the Senate, then controlled by [Democrats]. … That gave them the votes they needed on health care. That didn't give them the votes they needed on cap and trade because of the regional nature of these issues," with opposition from rural lawmakers concerned about the plan's cost.

FERC Filling the Gaps

Last week's discussion also touched on FERC's interpretation of the Federal Power Act's directive to ensure just and reasonable rates.

"Even though the law talks about rates and charges, FERC has looked at this language over time and said, 'You know what: If utilities aren't planning their transmission grid in the right way, if they're not cooperating regionally to plan the transmission grid, that might lead to rates that are unjust or unreasonable,'" Kavulla said. "'And therefore, we're asserting jurisdiction over the way the grid is planned for, paid for and built.'"

Hassenboehler said Congress should be "more assertive" in giving FERC direction, through letters and oversight hearings, such as that held by the Senate Energy and Commerce Committee in June. (See *FERC Probed on RTO Governance, Market Issues*.)

"The way things are rapidly innovating in the electric space, there's a lot of tough questions out there that FERC is struggling with … and it really all comes down to the power of states versus the feds. … And there's been no consensus or leadership on that issue in a while. … I think legislation is building over the next several years for that."

Hayes said FERC's interpretation of the FPA is a recognition of the limits of legislation on complex issues. "Congress can oftentimes get itself 80, 90, 95% of the way through to the answer on a policy question or problem and secure the votes that are required to make some associated change. But that last 5% can be the technically challenging, politically challenging [issues]. You may just run out of time to answer the question" in a two-year congressional term.

Hayes said he'd like to see the federal government assert jurisdiction over the environmental performance of electric generation.

"Some folks, states' rights advocates … don't want them to have that because they are fine with the [state-by-state] patchwork" of environmental policies.

"But I think that those environmental issues are decidedly global in nature. At a minimum … they are national in nature as policy questions. They're not confined to a single state. You've got to get to all 50 [states], or you haven't really addressed the issue."

Hassenboehler agreed there are some issues on which the federal government should assert jurisdiction, noting, "We don't have 50 different labels for food [ingredients]."

He said Congress should tackle the issue of "how data is utilized in the [energy] system: who gets to collect it; who gets to own it."

"This is energy data, emissions data, things that are being collected across the energy supply chain," Hassenboehler said. "There's a lot of need for some systematic consistency." ■

CAISO/West News

Calif. Wildfire Relief Bill Signed After Speedy Passage

By Hudson Sangree

SACRAMENTO, Calif. — Gov. Gavin Newsom signed a bill Friday that's meant to shore up the state's investor-owned utilities against wildfire liability.

Newsom pushed lawmakers to quickly pass *Assembly Bill 1054*, which they did in less than a week after it was amended to reflect the governor's wildfire plan. It takes effect immediately as an urgency measure.

"I want to thank the legislature for taking thoughtful and decisive action to move our state toward a safer, affordable and reliable energy future," the governor said in a statement after the State Assembly gave the bill its final approval Thursday. "The rise in catastrophic wildfires fueled by climate change is a direct threat to Californians."

The bill does not give utilities the relief from California's strict liability standard, known as inverse condemnation, which they wanted. But it would create a $21 billion fund to pay for wildfire damages, to be bankrolled equally by ratepayers and the state's three large investor-owned utilities.

Under the measure, the IOUs would contribute an initial $7.5 billion in aggregate and pay $3 billion more over the next 10 years. Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric would cover 64.2%, 31.5% and 4.3%, respectively, based on the size of the utilities and the miles of power lines that run through high-fire-risk areas.

Ratepayers would fund their $10.5 billion share through charges on electric bills, averaging a few dollars per month.

Elected officials hope the fund will head off further downgrades by credit rating agencies of SCE and SDG&E and alleviate concerns those utilities, like PG&E, could wind up in bankruptcy.

(The bill allows utilities to opt for a $10.5 billion state-backed line of credit in lieu of the wildfire fund. They must choose within 15 days. The general belief is they will opt for the wildfire fund.)

PG&E filed for bankruptcy in January, citing billions of dollars in wildfire liability from November's Camp Fire, the deadliest in state history with 85 fatalities, and a series of devastating blazes in 2017.

SCE's equipment is suspected of starting the Woolsey Fire, also in November 2018, which killed three people and destroyed more than 1,600 structures. The utility also faces massive liability for 2017's Thomas Fire, which it admitted may have been sparked by its equipment. That fire killed two people, while ensuing mudslides caused by rain drenching charred hillsides caused 21 deaths. (See *Edison Takes Partial Blame for Wildfire in Earnings Call*.)

SCE and SDG&E each had their credit ratings downgraded, although the latter hasn't had a significant utility-sparked fire in years, since it began a major grid hardening effort that's often cited as a model.

Stabilizing California

Those who supported the bill said bolstering the utilities against insolvency would allow fire victims to be compensated more quickly and maintain stable rates for customers.

"We're talking about victims, ratepayers and the industry that keeps the lights on," said Assemblyman Chris Holden, one of the bill's three co-authors and chairman of the Assembly Utilities and Energy Committee.

The measure requires PG&E to exit bankruptcy by June 30, 2020, and pony up its share of the initial $7.5 billion before it can recoup costs from the wildfire fund.

It also requires the IOUs to pay a combined $5 billion for fire-safety upgrades without recouping profits from ratepayers through a return on equity.

Assemblywoman Eloise Reyes said she struggled with the bill but decided to vote "yes" because she felt it would compel PG&E to leave bankruptcy and prioritize safety, while stabilizing electric service and rates in California.

"In the end, our job is to stabilize California," Reyes said.

While speakers on the Assembly floor Thursday generally praised the bill and urged its passage, others remained troubled.

Assemblyman Al Muratsuchi, a Los Angeles-area Democrat, asked "whether we could have done better if we had more than two weeks" to weigh the measure. The bill, in its current form, was first printed late last month and then heavily amended July 5 over the holiday weekend.

It cleared two state Senate committees July 8

A DC-10 airtanker battles the Woolsey Fire last November. | *U.S. Forest Service*

before being passed by the upper house, all in a matter of hours. (See *Calif. Lawmakers Rush to Pass Utility Wildfire Aid*.)

Last year, lawmakers hastily passed Senate Bill 901, another major wildfire bill, under pressure from then-Gov. Jerry Brown and legislative leaders. They were told if they didn't pass the bill, PG&E would go bankrupt, which it did anyway.

"Now we're being asked to pass this bill, and if we don't pass it [by July 12] according to the governor ... then Edison is going to be downgraded to junk bond status and may face bankruptcy," Muratsuchi said. He questioned whether the utility would follow the same course as PG&E.

Assemblyman Marc Levine, a Democrat who represents a district north of San Francisco, voted "no" on the measure and said it was not right to offer PG&E assistance when it had yet to upgrade its power lines to prevent fires.

The Caribou-Palermo transmission line that sparked the Camp Fire was 100 years old, and maintenance had been deferred repeatedly, leading to 85 deaths, he said. Other PG&E lines in high-risk areas may be in similar condition, he said.

"It is hard not to see this bill as a reward for monstrous behavior," Levine told his colleagues. "They have not done the work. They should not be rewarded." ■

CAISO/West News

Newsom Names New California PUC President

By Hudson Sangree

Marybel Batjer will be the new CPUC president. | *State of California*

California Gov. Gavin Newsom announced his choice Friday for a new leader of the state's Public Utilities Commission.

Marybel Batjer, currently the state's government operations secretary, will soon replace retiring President Michael Picker, Newsom said. He called Batjer "one of the best in the business."

"She is about reorganization," Newsom said. "She is about governance."

Batjer's official *biography* says she was appointed by former Gov. Jerry Brown in 2013 to head the Government Operations Agency, a new entity charged with improving efficiency and accountability in state government as part of Brown's reorganization efforts.

Newsom kept her on in that role and gave her the job of reforming the Department of Motor Vehicles, one of the state's most inefficient bureaucracies.

"She has led forward-looking efforts to revamp the way the state approaches data and technology, modernized the civil service system, and has led the implementation of key initiatives to green state government and promote renewable energy," Newsom's office said in a *news release*.

"Prior to taking office at CPUC, Batjer will complete her work later this month as head of Gov. Newsom's DMV Strike Team, which has already begun implementation of key changes to transition the California Department of Motor Vehicles into a more customer-friendly and user-centered culture, to better serve Californians," it said.

She's expected to take office at the CPUC at the beginning of August.

Previously, Batjer was vice president of public policy and corporate social responsibility for Caesars Entertainment. Her state and federal government experience includes stints as Gov. Arnold Schwarzenegger's cabinet secretary, special assistant to the secretary of the Navy in the George H.W. Bush administration and a national security adviser in the Reagan administration.

Newsom made the announcement during a press conference and signing ceremony for Assembly Bill 1054, a major new wildfire law that will be implemented in part by the CPUC. (See *Calif. Utility Relief Bill Speeds to Governor*.)

The CPUC has come under fire in the last year for moving slowly in response to California's wildfire crisis. There were rumors months ago that Newsom intended to appoint his own CPUC president to replace Picker, a former aide to Gov. Jerry Brown.

Picker said in a recent interview with *RTO Insider* that Newsom hadn't asked him to leave, but that he felt it was time to retire. (See *Retiring CPUC President Still Has Lots to Say*.)

Newsom thanked Picker for his service Friday.

"Michael has brought deep expertise in energy policy and a commitment to advancing the state's climate goals," the governor said in a statement. "His knowledge, vision and commitment has been critical as the state examines the role of utilities following recent catastrophic wildfires and necessary changes in an era of climate change."

Picker was unavailable Friday, according to an aide. Batjer could not immediately be reached for comment. ■

Gov. Gavin Newsom named his new CPUC president during the signing ceremony for a landmark wildfire bill Friday. | © *RTO Insider*

CAISO/West News

Customers Probe BPA on EIM Impact

By Robert Mullin

PORTLAND, Ore. — Bonneville Power Administration officials July 8 likely dispelled any lingering doubts about their intent to join the Western Energy Imbalance Market, but it will take some time to address stakeholders' questions about how the move will affect them.

BPA last month circulated a *letter* to its customers seeking comment on a plan to sign an implementation agreement with CAISO this September as a first step to joining the EIM. While that agreement would be nonbinding, it would also commit the federal power agency to shelling out a $1.8 million nonrefundable implementation fee, the first of $30 million to $35 million in estimated start-up costs. BPA will not issue its final record of decision on becoming a member until late 2021, just months before it plans to join in March 2022. (See *BPA Marches Toward EIM Membership*.)

A proposal attached to that letter detailed the raft of benefits of joining the EIM, including more efficient generation dispatch, as well as improved transmission usage, congestion management and voltage control. BPA also touted the ability to use the EIM as a "non-wires" solution to address congestion and avoid new transmission builds while also helping to identify areas of needed investment.

Some BPA "preference" customers attending the last in a series of "EIM stakeholder" meetings July 8 sought to get into the weeds of what EIM membership would mean for them and their workaday relationships with the federal power agency. Those customers represent the Pacific Northwest's publicly owned utilities, which get first priority for the energy coming off the Columbia River Power System managed by BPA.

Tom Haymaker, manager of energy planning and operations for Clark Public Utilities in Washington, said he'd been "wrestling" with the issue of the "interplay" between the region's existing hourly bilateral market and the EIM's intra-hour market — and how BPA would make decisions about offering energy into each after joining the EIM.

"We're going to be a player in the real-time hourly market, but we won't be in the intra-hour market," Haymaker said. "Are we going to be precluded from getting access to certain kinds of power from Bonneville because you're wanting to put that into the intra-hour, or is there going to be some sort of process where we would have an opportunity to perhaps buy that power ahead of time that you were planning to offer up in the intra-hour?"

From left: BPA's Todd Kochheiser, Suzanne Cooper, Steve Kerns, Russ Mantifel, Rebekah Pettinger and Tom Davis | © *RTO Insider*

Steve Kerns, BPA's director of grid modernization, offered a roundabout answer. After explaining that the agency already trades in a "very complex set of markets," he recounted a previous trip to SPP, whose market participants told him that real-time bilateral markets started to "go away" after the roll-out of the RTO's Integrated Marketplace.

"That's almost the inevitable outcome here. ... So that means we have to be smarter about how much we want to take to real time," Kerns said. "If we think that the [bilateral] market depth in general is going to be less than what it is pre-EIM, we're going to have to make different decisions about day-ahead marketing than what we did in the past and also consider what we want to roll into the Energy Imbalance Market."

Kerns said that, like hydro-heavy EIM member Powerex, BPA is not going to stop trading in the bilateral market. "They participate in the EIM, but they still participate in the real-time market as well."

Haymaker expressed concern that BPA would at times "park" power, reserving it for sale into the EIM rather than making it available to its preference customers.

"We certainly don't feel we would need to do that in order for the EIM to pencil out," said Russ Mantifel of BPA's transmission marketing and sales division. "Joining the EIM does not make future policy decisions about what we're going to offer up. In order for us to achieve the benefits, I think we don't have to make the sort of zero-sum decisions that you're talking about here."

Haymaker agreed that "the more markets, the better," an acknowledgment that BPA preference customers pay lower prices for their contracted power when the agency gets higher prices for its surplus sales — which effectively subsidize preference customers.

"I think you're going to find better pricing in the real-time market after you do this because you've got alternatives, so we understand that. But we want access, or the ability to compete

CAISO/West News

with that intra-hour market," Haymaker said.

"The heart of a lot of this is how do you meet your statutory obligations for both regional preference and preference for the consumer-owned utilities," said Betsy Bridge, an attorney representing Northwest Irrigation Utilities. "It's not a question of whether the preference customers get first dibs to that power — so it's a balancing act. But to reiterate Tom's point, we have to find a balance there of making sure that preference customers have the first opportunity."

"And it's an assumption that we will meet those obligations," Mantifel said. "We're confident that joining the market does not create any issues with our ability to do that and that a lot of market changes are going to make that more complicated moving forward — the proliferation of the EIM being one of them."

Tx Questions

Anna Berg, senior manager of power supply for Snohomish County (Wash.) Public Utility District, wondered how transmission curtailments would affect resources not participating in the EIM.

"What does that look like for the rest of us who are using BPA's point-to-point transmission or [network transmission]?" Berg asked. "So, if there's congestion that is occurring between EIM entities, how is that resolved?"

Saying he would be "riffing a little bit" in his response, BPA's Todd Kochheiser explained that — "where appropriate" — transmission operators would still likely curtail prior to the hour in the face of commercial congestion. But he noted that the EIM also ensures that participating balancing authorities begin the hour with adequate resources by applying a "resource sufficiency test" that also includes a transmission feasibility assessment.

"I could envision as a result of that assessment, we could potentially identify transactions or tags or base schedules that need to be adjusted, either through curtailments or some other mechanism, in order to go into each hour feasible," Kochheiser said. "To the extent there ends up being congestion within the hour ... the market will use available resources that have been bid into the market to try to resolve that congestion. Failing that, I think we would be left with no alternative other than other operational tools such as curtailments, redispatch, etc."

Mantifel added that, "Even if you're not participating in the market, the odds of a curtailment ought to be reduced due to the active redispatch of the market, so the market will proactively try to get the flows below whatever physical limits that we're managing within the market."

Lauren Tenney, senior policy analyst with the Public Power Council, asked whether BPA expected to see congestion benefits focused primarily in areas where transmission is "donated" to the EIM to facilitate transfers between balancing authorities — known as energy transfer system resources (ETSRs) — or whether there would be enough donated transmission to spread the benefits.

Mantifel said he didn't think there was a strong correlation between benefits and the number of ETSRs.

"The market's always working to manage the transmission system better, even if there's no ETSRs," he said, adding that it's not always clear when the EIM is just providing economic benefits rather than relieving a stressed system.

'Sound Business Decision'

BPA's resolve to join the EIM became evident during a hair-splitting discussion in which a few stakeholders pressed agency officials on whether the agency had already determined that it would be a "sound business decision" to join the EIM — or if that determination only extended to the signing of the nonbinding implementation agreement.

"I think it is a sound business decision," Mantifel said of joining the EIM. "I mean, this is what we're establishing. We've gone through a pretty arduous process of establishing what we believe to be facts and assumptions and analysis that justify this as a sound business decision. … If you think the facts are wrong, if you think they're insufficient, if you think the analysis is wrong or insufficient in scope or detail, this is your opportunity to disagree with that."

Stakeholders have until July 22 to submit comments on the plan.

Tenney sought to clarify whether BPA would still in some way revisit the "sound business" issue before issuing its record of decision in two years.

"If nothing changes between now and the final decision, would this issue be something that's addressed in a final letter to the region?" she asked.

Kerns confirmed that it would, and then attempted to reframe the subject:

"If we do decide to join the Energy Imbalance Market, what strategic value do we get as being a player and helping form the markets? On the other side of the coin, what is the strategic risk to Bonneville of being potentially one of the only balancing authorities on the West Coast not participating in the market? So, I think there's two ways to look at that." ■

CAISO/West News

Gas Spike Drove High CAISO Power Costs in Q1

CRR Auction Revenues vs. Payments Improve

By Hudson Sangree

A huge spike in natural gas prices drove up the cost of wholesale electricity in CAISO by more than 40% in the first quarter of 2019 compared with the same period a year ago, the ISO's Department of Market Monitoring reported.

However, the disparity between income and payments for congestion revenue rights dramatically improved since the first quarter of 2018, lessening costs for ratepayers, the department said.

The Monitor reported the mixed first-quarter results in a July 2 *web conference*.

Amelia Blanke, CAISO manager of monitoring and reporting, said it cost about $2.7 billion — or $55/MWh — to serve load in the ISO's territory during the first three months of this year. That was a 42% increase from Q1 2018.

Gas prices were 73% higher in the first three months of 2019 than they were in the first quarter of 2018, the Monitor reported. Lower temperatures, high heating demand, and supply constraints led to gas prices that more than doubled from January to February of this year.

"High natural gas prices in February 2019, at both SoCal and PG&E Citygate, were the main driver of high system marginal energy prices across the ISO footprint," the Monitor said in its Q1 *Report on Market Issues and Performance*.

As a result, average day-ahead electricity prices increased "by around $17/MWh (almost 50%), 15-minute by about $15/MWh (45%) and five-minute market prices by $13/MWh (35%) in comparison to the same quarter in 2018," it said.

The Monitor noted that natural gas units are often the marginal source of generation in CAISO and the rest of the West.

The Northwest Sumas gas hub in the Pacific Northwest saw record high gas prices during the winter months of 2019.

"The price spike comes amid limited supply deliverability and unseasonably cold temperatures, which drove up demand in the Northwest," the Monitor said. "Prices at the Sumas gas hub have been volatile since the Oct. 9, 2018, Canadian gas pipeline explosion reducing imports into hubs in the Northwest." (See *NW Price Spike a Wake-up Call,' Ex-BPA Chief Says*.)

The high gas prices were offset by increased generation from wind and hydroelectric resources.

"Compared to 2018, hydroelectric production in the first quarter increased by roughly 47%," the report said.

The extremely wet winter in California increased snowpack to 175% of normal on April 1, compared to 58% of normal on the same date in 2018.

Compared to the first quarter of 2018, wind production increased while solar production dropped slightly, despite increased solar capacity. "This was likely due to greater curtailments resulting from high hydro and wind production," the Monitor said. "In March 2019, renewable curtailment reached record levels, roughly 125,000 MWh."

"The ISO became a net exporter on average during peak solar hours [noon to 3 p.m.] over the entire quarter, as imports fell and exports increased in these hours relative to prior quarters," the Monitor added.

Closing the Gap in CRRs

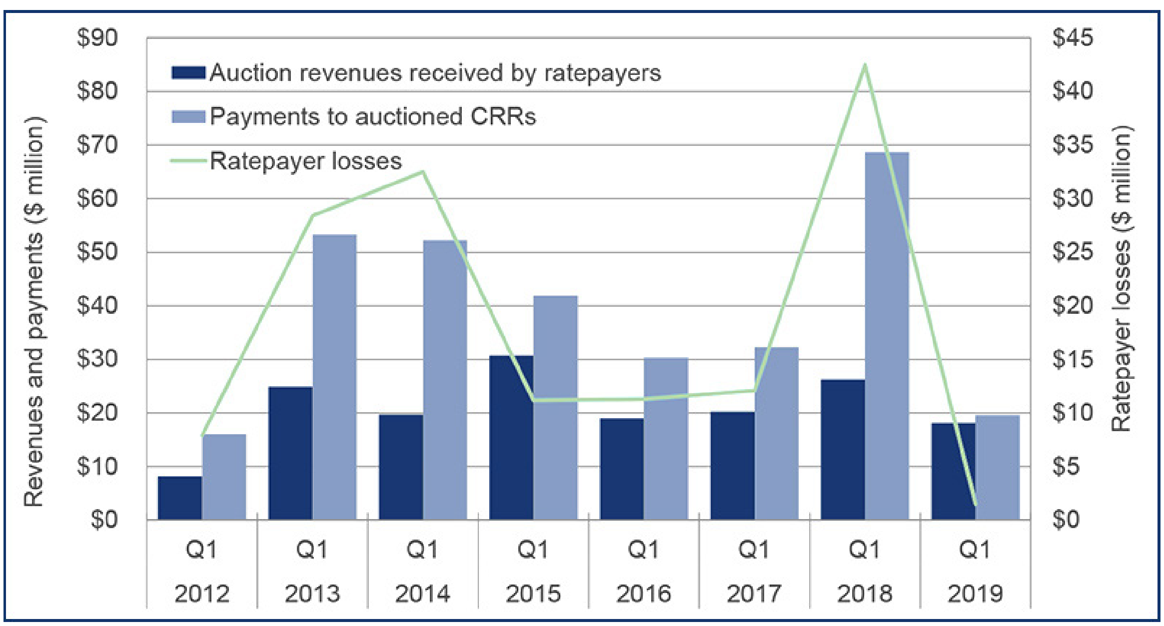
The first-quarter 2019 results also suggested that changes CAISO implemented last year to CRR auctions are working.

The Monitor reported that income from the auctions fell short of payments to purchasers by $1.5 million in the first quarter of 2019 — a sharp drop from the $43 million difference in the first quarter of 2018.

Payments and revenues were closer to parity than in any first quarter since 2012, the Monitor reported.

Ratepayers have been covering big losses in the CRR auctions since they were implemented in 2009. The total loss is now about $860 million, the Monitor said in its report. (See *CAISO Q4 CRR Revenues Falling Short After Summer Surplus*.) The main beneficiaries have been financial entities that purchase the CRRs, betting on profits.

"The decrease in losses to transmission ratepayers from sales of congestion revenue rights is due in part to changes to the auction implemented by the ISO in 2019, which limit the source and sink of congestion revenue rights that can be purchased in the auction," the Monitor said. ■



The gap between auction revenues and payments to owners of congestion revenue rights in CAISO fell in Q1. | *CAISO*

CAISO/West News

FERC Proposes $6.8M Fine for CAISO Market Manipulation

Vitol Trader who Helped Create CAISO's CRR Software Gamed System, FERC Says

By Hudson Sangree

FERC on Wednesday ordered energy firm Vitol and one of its senior traders to show cause why they should not be fined for manipulating CAISO's market to limit losses on the company's congestion revenue rights (*IN14-4*).

The trader, Federico Corteggiano, had helped create software for CAISO's CRR market and had engaged in similar market manipulation before while at Deutsche Bank, FERC's Office of Enforcement said.

Federico Corteggiano, Vitol | *LinkedIn*

In the more recent instance, he sold power at a loss of about $4,500 to save Vitol more than $1.2 million on its CRRs, FERC's enforcement staff alleged.

In its ruling, FERC proposed ordering Vitol to return the savings, with interest, and fining it $6 million. The commission proposed fining Corteggiano $800,000. The commission gave Vitol and Corteggiano 30 days to respond.

Vitol and Corteggiano disputed FERC's findings in testimony and prior filings, saying the trades were intended to take advantage of high prices, not to benefit Vitol's CRRs. FERC found the arguments unpersuasive.

In their report, FERC enforcement staff said that during five days in the fall of 2013, Vitol "sold one product — electric power — at a financial loss in CAISO's day-ahead market to benefit its separate financial product — respondents' congestion revenue rights. Corteggiano, co-head of Vitol's financial transmission rights trading operation, was the architect of this scheme."

In 2013, Corteggiano purchased CRRs through CAISO's auction for the Cragview node, the point where CAISO transfers power from the PacifiCorp-West balancing authority area in far Northern California.

The LMP at Cragview reflects 100% of the congestion on the Cascade intertie, the FERC report noted. "Vitol's CRRs would earn money from import congestion on the Cascade intertie and lose money from export congestion," it said.

In mid-October 2013, CAISO partially derated the Cascade intertie — limiting exports while still allowing imports during portions of late October, November and December. In October, Cragview's LMP hit an unusual high of more than $388/MWh. Export congestion accounted for about $350/MWh of that price, FERC said.

Vitol's export CRRs would lose money every hour. The firm was able to buy counter-flow CRRs for November and December, mitigating its losses and flattening its position, FERC said. "However, because the monthly CRR auction for October had closed, it was too late to flatten Vitol's CRR position for the last week of October."

Corteggiano, who holds a Ph.D. in power system engineering, found a way to get around that problem — one he'd used before, FERC staff alleged.

"Corteggiano knew that he could likely eliminate the problematic export congestion for that week by importing physical power in the day-ahead market at Cragview. Working with other Vitol employees, Corteggiano arranged to buy [5 MW of] physical power in the Pacific Northwest and successfully offered it for import at Cragview. Vitol's imports over the Cascade intertie achieved their intended purpose, preventing export congestion from occurring during the period of Vitol's imports. ...

"Respondents lost money on the imports, but by making them, [they] were able to eliminate the export congestion and thereby avoid the far larger financial losses they otherwise would have incurred on the CRRs at Cragview."

'Phantom Congestion'

While at Deutsche Bank, Corteggiano had figured out how to manipulate congestion costs at another partially derated intertie linking CAISO to northern Nevada, FERC staff said. He had bought CRRs that profited Deutsche Bank when there was export congestion on the Silver Peak intertie but lost money when there was import congestion.

"In January 2010, CAISO partially derated the Silver Peak intertie to 0 MW in the import direction and 13 MW in the export direction. Import congestion appeared on the intertie, and Corteggiano's CRRs began to lose money. Corteggiano found that he could substantially alter or eliminate what he called 'phantom congestion' by trading small quantities of physical power in the opposite direction of the derate," FERC enforcement staff said.

"Corteggiano testified that 'phantom congestion' is 'congestion that is not triggered by market behavior or by physical flows in the system,'" the report said. "'Phantom congestion' is Corteggiano's own description of a pricing outcome rather than an industry-recognized term.

"Corteggiano admitted to Enforcement in 2010 that he made unprofitable physical trades on behalf of Deutsche Bank to benefit CRR positions that otherwise would have been harmed by the congestion associated with partial derates at Silver Peak. This was the only time in his career that Corteggiano traded physical power, until he did so at Cragview in late October 2013," FERC said.

Enforcement staff investigated Corteggiano's conduct at Deutsche Bank, resulting in the settlement of manipulation allegations with Deutsche Bank, a civil penalty of $1.5 million and disgorgement of $172,645, plus interest, in January 2013 (*IN12-4*).

At the Cragview node, "Respondents' manipulative trading enabled Vitol to avoid paying CAISO $1,227,143 on Vitol's CRRs," the report said. "Moreover, respondents caused $2,515,738 in market harm consisting of (a) $2,429,385 in reduced funding of CAISO's CRR balancing account, and (b) $86,353 in losses suffered by the holders of CRR counterflow positions at Cragview.

"Although Corteggiano was not identified by name in the Order to Show Cause in the Deutsche Bank enforcement matter, the public Enforcement staff report attached to the order explained his central role in the trading scheme and referred to him by name," the report said.

CAISO's CRR auction has cost ratepayers $860 million because of the difference between revenues and payments to CRR holders, the ISO's Department of Market Monitoring has found. The ISO has tried to stem the losses through changes to its CRR auctions, which appeared to reduce the disparity between payments and income in the first quarter of 2019. (See *Gas Spike Drove High CAISO Power Costs in Q1*.)

Vitol was one of the companies that opposed those changes last year. (See *FERC OKs Tighter Rules for CRR Auctions*.) ■

ERCOT News

SPS, Entergy File to Pull ROFR Appeal

Independent Transcos Oppose Withdrawal

By Tom Kleckner

Saying recent Texas legislation has rendered their case moot, Entergy, Southwestern Public Service and Texas Industrial Energy Consumers have asked to dismiss their appeal of a Public Utility Commission order negating an incumbent utility's right of first refusal (03-18-00666-cv).

The parties *told* the Texas Third Court of Appeals in Austin on June 21 that *Senate Bill 1938*, passed in May, has "mooted the underlying controversy": an appeal of a 2017 PUC ruling that SPS does not have the exclusive right to build transmission facilities in its service territory.

But Southwest Transmission and GridLiance High Plains asked the Texas court on June 27 to reject the motion to dismiss pending the resolution of a separate federal court challenge to the legislation.

The bill, which Gov. Greg Abbott signed on May 16, amended the Public Utility Regulatory Act to grant certificates of convenience and necessity (CCNs) to build, own or operate new transmission facilities that interconnect with existing facilities "only to the owner of that existing facility." That essentially cuts out independent transmission companies from competing for projects anywhere in Texas, including for FERC Order 1000 projects in non-ERCOT areas. (See *Texas ROFR Bill Passes, Awaits Governor's Signature*.)

In their filing, the parties said the Texas Legislature "has thus clarified that Texas law" gives SPS and Entergy "the exclusive right to build new transmission lines in their respective service territories."

The parties also said the bill clarifies the Legislature's intent to retain the state's jurisdiction over retail rates in non-ERCOT areas of Texas "by effectively prohibiting the certification of new-entrant, transmission-only utilities whose rates would be subject to FERC's exclusive jurisdiction."

Because no transmission-only utilities currently operate in Texas's non-ERCOT regions, the parties said, "the exclusivity provisions and limitations on transfers of certificate rights to utilities already certified within a particular power region will act as a bar to any future certification of such entities."

| *Wind Energy Transmission Texas*

Entergy, SPS and TIEC, a trade association of the state's largest consumers, had appealed a Travis County District Court ruling that agreed with the PUC's 2017 order (Docket *46901*). The commission ruled that existing law did not give SPS a ROFR, and that it could award CCNs to transmission-only utilities in the state's non-ERCOT regions. (See *Texas Commission Rejects SPS ROFR Request*.)

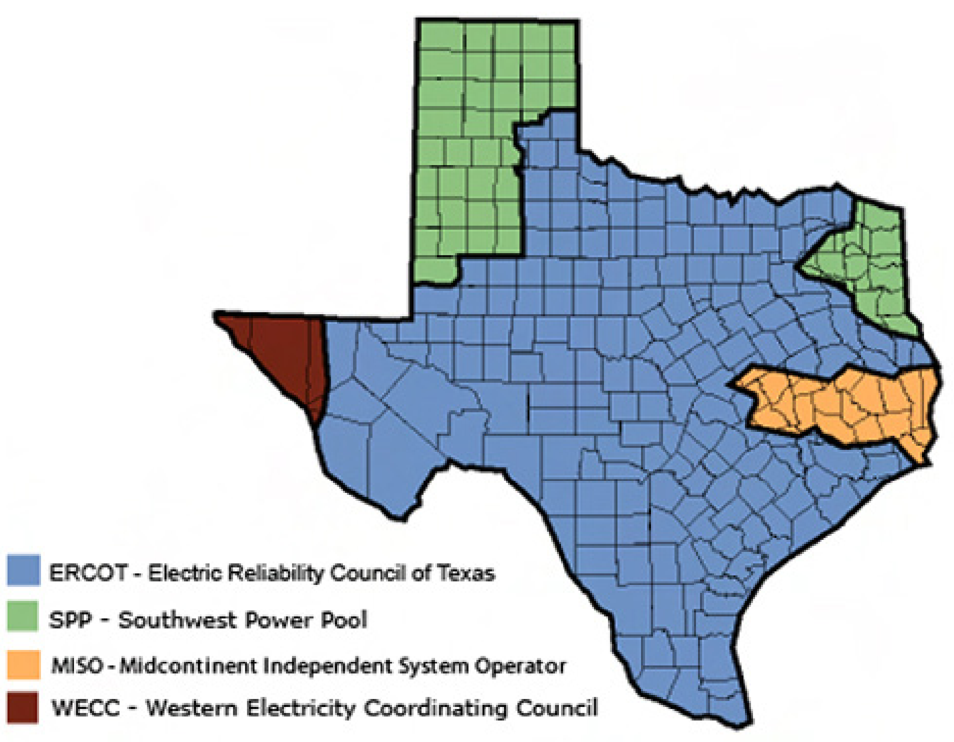
The PUC told the court June 27 that it was "unopposed" to the motion to dismiss.

But Southwest Transmission and GridLiance High Plains asked the court to consider staying the case pending NextEra Energy's challenge of the constitutionality of SB 1938. (See *NextEra Takes Texas to Court over ROFR Law*.)

NextEra's challenge, filed in the U.S. District Court for the Western District of Texas on June 17, alleges SB 1938 is unconstitutional because it violates the dormant Commerce Clause and the Contracts Clause.

"It is entirely possible that the federal district court may decide that the PURA provisions enacted under SB 1938 are, as alleged in NextEra's lawsuit, unconstitutional and thus invalid and unenforceable," the companies said. "A dismissal of the [Texas] appeal at this juncture, when NextEra's lawsuit is pending, would potentially result in a still valid trial court judgment being vacated and the need for one or more of the parties to this case to refile and pursue a new, redundant appeal of the underlying PUC decision."

NextEra transmission subsidiaries had won a competitive bid for a MISO 500-kV project in Southeast Texas and had a CCN application pending before the PUC to assume ownership of 138-kV facilities in Northeast Texas. ■



RTO boundaries in Texas | *ERCOT*

ERCOT Briefs

Stakeholders near Consensus on RTC's Principles

ERCOT staff and stakeholders are preparing to bring a first set of real-time co-optimization (RTC) policy principles to the Technical Advisory Committee in a key test of their efforts to improve the Texas grid operator's market design.

The Real-Time Co-Optimization Task Force, which is responsible for developing the RTC principles to align the ERCOT market with the direction given by the Public Utility Commission of Texas, will present five key principles to the TAC for approval during its July 24 meeting:

- KP 1.4: System inputs into RTC
- KP 1.5: Process for deploying ancillary services (AS)
- KP 1.6: AS imbalance settlement with RTC
- KP 3: Reliability unit commitment
- KP 4: Supplemental AS market (SASM)

Stakeholders will debate KPs 1.5 and 3 and their alternative positions before the committee.

Matt Mereness, ERCOT | © *RTO Insider*

"The votes at the July TAC meeting will be a good indicator of whether the RTC Task Force's efforts will be efficient in moving key design decisions through the stakeholder process," said task force Chair Matt Mereness, ERCOT's compliance director, following the group's meeting Friday.

The task force is following guidelines set by PUC Chair DeAnn Walker for RTC, a market tool that procures both energy and AS every five minutes to find the most cost-effective solution for both requirements. (See *ERCOT Real-time Co-optimization Falls into Place*.)

Mereness said it was "helpful" to "have the PUC set direction on a number of key design issues."

The RTCTF is also trying to engage other RTOs on lessons learned with their design and implementation of RTC. It hopes to bring MISO, PJM and SPP to Texas for a meeting in September.

ERCOT Comes Close to June Demand Record

The ERCOT system came about 1.5% shy of setting a new demand record for the month of June when it recorded a peak of 68.1 GW on June 19, compared to the all-time record set last year at 69.1 GW.

June's peak set a high for the year that has since been broken in July. The system twice surpassed 70 GW on Wednesday, registering a peak demand of 70.5 GW for the hour ending at 5 p.m.

ERCOT is expecting a record peak demand this summer of 74.9 GW, 1.4 GW higher than the all-time record of 73.5 GW set last July. The grid operator has 78.9 GW of available capacity. ■

— Tom Kleckner

ISO-NE News

New England Officials Speak on Grid Transformation

By Michael Kuser

WESTBOROUGH, Mass. — State and regional officials last week updated the Environmental Business Council of New England (EBCNE) on the rapid progress of renewable energy development across the region.

Mark Tisa, Massachusetts Division of Fisheries and Wildlife | © *RTO Insider*

The debriefing took place at the Massachusetts Division of Fisheries and Wildlife headquarters, the first state-owned building to achieve net zero energy use. Director Mark Tisa said he was proud of having served as the agency's lead on its construction in 2012, and that the LEED Platinum certified building sits on 1,000 acres of protected and open space, a small slice of the more than 225,000 acres of such land under its management in the state.

Catherine Finneran, Eversource Energy | © *RTO Insider*

"We're very lucky to live and work in this region, in this sector, with these leaders that you'll hear from today," said Catherine Finneran, director of environmental affairs at Eversource Energy, introducing the speakers. "They're really leading innovative programs that are ahead of many other states and regions to tackle both energy and environmental challenges that we face as a region."

Wind Jumps the Queue

Eric Johnson, ISO-NE | © *RTO Insider*

"When we think about the resource mix, what's been proposed in the region, we think of this as the generator interconnection queue ... for many years it was dominated by gas-fired generation," said Eric Johnson, ISO-NE director of external affairs, who serves as president of the Connecticut Power and Energy Society.

EBCNE President Daniel Moon welcomes regional state energy officials to update his members at the Massachusetts Division of Fisheries and Wildlife Headquarters on July 11. | © *RTO Insider*

Natural gas "has actually dropped to about third place in the queue, and by far the largest resource now is wind, primarily offshore wind," he said.

"Most of the wind used to be proposed in Maine, but now we're seeing a lot of that happen in southern New England, in the offshore space, with Massachusetts alone at over 6,000 MW," Johnson said. "We see that in Rhode Island and Connecticut."

The region will not need 20,000 MW of new resources on a system that peaks at 28,000 MW, so not every project that developers propose will get built, but every proposal must go through the RTO's study process, he said.

"Battery storage was not even in my presentation a couple years ago, then it showed up at about 50 MW, then 100 MW, then 200 MW, then 800 MW, and now it's out of date as soon as we print it," Johnson said. "So now we have almost 2,400 MW of battery storage in New England, and a lot of that is driven by policy direction set by the states."

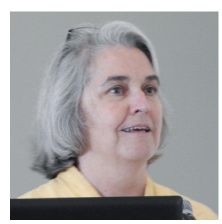
New England has also experienced tremendous growth in solar, he said: "In 2010, we had 40 MW of solar on the system, and if you go in the control room now, that doesn't even show up. That's noise."

Land Ho is Wind Woe

Judith Judson, Massachusetts DOER | © *RTO Insider*

Commissioner Judith Judson of the Massachusetts Department of Energy Resources responded to a question about the Edgartown Conservation Commission having the previous day denied a permit for Vineyard Wind's cables to come ashore on Martha's Vineyard — and about the Bureau of Ocean Energy Management in June having declined to issue its final environmental impact statement on the 1,200-MW offshore wind project.

"We're absolutely committed to offshore wind. We just doubled down on it very recently, and I think developing projects is challenging," Judson said. "That is a fact. I think siting large projects is challenging because of the amount of neighbors and the amount of entities impacted. Hopefully we can work through those challenges ... you sometimes get setbacks. We're out now with our second solicitation for offshore wind, and I'm hoping for a robust response. It's unfortunate and no one wants to see these types of delays."



Carol Grant, Rhode Island OER | © *RTO Insider*

Rhode Island Office of Energy Resources Commissioner Carol Grant said, "The offshore industry comes from Europe, and honestly, their interactions with different states have them scratching their heads sometimes. They'll say, 'Really, we've dealt with the feds, now there's another state and another state and another state.'"

Matthew Mailloux, New Hampshire OSI | © *RTO Insider*

Matthew Mailloux, energy adviser in the New Hampshire Office of Strategic Initiatives, said his state has formed an offshore wind task force, begun the formal lease application process with BOEM, and initiated a regional collaboration

ISO-NE News

on offshore wind with Maine and Massachusetts, aided by EBCNE.

Mailloux said a letter from Gov. Chris Sununu to BOEM in January led to creation of the agency's Intergovernmental Renewable Energy Task Force.

Dan Burgess, Maine GEO | © *RTO Insider*

Dan Burgess, director of Maine Gov. Janet Mills' Energy Office, touted his state's direction toward offshore wind.

"The previous administration, in power for eight years, had done away with energy planning, but we're bringing it back," Burgess said.

He highlighted the revival of the Maine Aqua Ventus project to test a floating turbine off the coast, which he said is "important because the water is too deep off Maine for fixed-bottom turbines."

Burgess also said that a bill in the Maine legislature (*LD 1646*) to have the state take over and own the Central Maine Power and Emera Maine utilities "has gotten a lot of attention" and will be the subject of a Public Utilities Commission study.

Grid Transformation

Anne Margolis, Vermont DPS | © *RTO Insider*

Anne Margolis, assistant director of planning for the Vermont Department of Public Service, said her state has a strong focus on modernizing rate design and getting people to use electricity at times of lower demand.

"We're distinct from the [Public Utility Commission]. ... We're the body that advocates on behalf of ratepayers and the state's energy policies," she said, adding that one utility, Green Mountain Power, serves 75% of load, and that Vermont represents 4% of New England load.

Eric Johnson, ISO-NE; Anne Margolis, Vermont DPS; Matthew Mailloux, New Hampshire OSI; Dan Burgess, Maine GEO; Commissioner Carol Grant, Rhode Island OER; and Commissioner Judith Judson, Massachusetts DOER. | © *RTO Insider*

Margolis complimented ISO-NE's Johnson on the RTO's recent Grid Transformation Day and said she appreciates the grid operator "flagging a potential issue" and offering a solution. (See *'Grid Transformation Day' Highlights ISO-NE Challenges*.)

Massachusetts' Judson asked, "How do we think about a grid that is no longer big power plants going on the transmission, stepping down onto distribution, but now is small generation, in aggregate large amounts of generation on a system that was never designed for that?"

Electricity constitutes 27% of the energy use in Massachusetts, behind transportation at 44% and thermal (building heating) at 39%.

"When we electrify the heating of buildings, we get a huge leverage effect from the investments we've already made. ... Combine that with energy efficiency, and you're getting massive benefits," Judson said. "We invest a tremendous amount in [energy efficiency]; [we'll] invest $2.7 billion over the next three years ... whereas California invests around $1 billion on a grid three times as large ... but we get great returns."

The DOER projects $9.3 billion in savings from the state's EE investment over the next three years.

"We still have these times of the year when we're overly dependent on natural gas, where our system, because of demands for heating and generation, has to switch to oil and other resources," Judson said. "We continue to need to think about that reliability constraint on our system. If you can do LNG, that can be something in the short term, that may be one solution, but how do you have that storage capability for that type of fuel given that longer term ... you're planning to transition away from it." ■

ISO-NE News

FERC Staff Hear Doubts on ISO-NE Fuel Security Plan

Continued from page 1

Last July, FERC ordered ISO-NE to develop a long-term plan to address concerns over insufficient natural gas supplies for generation in winter. (See ***FERC Denies ISO-NE Mystic Waiver, Orders Tariff Changes***.) In March, the commission pushed the original July 1 filing deadline back to Oct. 15.

In April, the RTO, the New England States Committee on Electricity (NESCOE) and the New England Power Pool requested the public meeting with staff, saying that ex parte rules had prevented stakeholders from seeking guidance from the commission.

Christopher Parent and Matthew White, ISO-NE | © *RTO Insider*

ISO-NE Chief Economist Matthew White and Christopher Parent, director of market development, opened the meeting Monday with an overview of the RTO's "energy security improvements" (ESI) proposal, which includes day-ahead energy option products, a multi-day-ahead market (M-DAM) and seasonal forward markets.

White said the proposal's energy option design — the only part of the proposal the RTO plans to file in October — solves the "misalignment" between the high price implicit in energy interruptions and the lower energy prices suppliers receive. The RTO gave its most recent outline of the proposal to NEPOOL members at last week's Markets Committee meeting. (See related story, "ESI Conceptual Design," ***NEPOOL Markets Committee Briefs: July 8-10, 2019***.)

Seeking Delay

Regulators and NEPOOL members told FERC staff Monday that the RTO's plan for a deterministic impact analysis was insufficient and should include probabilistic results. Some complained that the RTO had failed to adequately define the problem or had ignored how offshore wind, LNG tanker deliveries and energy efficiency could reduce winter concerns. And numerous witnesses said the RTO's plan to submit a Tariff filing in mid-October is premature.

Jeff Bentz, NESCOE's director of analysis, said the schedule could be delayed by six months without impacting the proposed implementation.

Jeff Bentz, NESCOE

"The ISO will not review its impact analysis until July 30. It will still be preliminary at the September 2019 Markets Committee vote, and a number of the modeling cases and specific assumptions are unclear at this point," Bentz said. "With that backdrop though, ISO is encouraging state and stakeholder proposal amendments by mid-August, which is about two weeks after we get the impact analysis. … We have more questions than firm views at this point."

NEPOOL Chair Nancy Chafetz, of Customized Energy Solutions, asked FERC to "keep an open mind" on the proposals. Although NEPOOL members have "jump ball" rights to propose an alternative to the RTO's proposal, Chafetz said the stakeholder body won't have an official position until it votes in October. And even then, she said, "some of our stakeholders may have difficulty in taking a position when we vote because of" the aspects of the plan that the RTO said it would have to deal with later.

Bentz and others also expressed concerns about the ability to mitigate market power. "We think it's going to be hard to mitigate these call options. There's a lot of subjective inputs in determining what your option bid is going to be," he said.

Phil Bartlett, Maine PUC

What's the Target?

Phil Bartlett, chairman of the Maine Public Utilities Commission, said the RTO's "problem statement" is not specific enough because it fails to define the level of reliability it is seeking.

"We think this is a very aggressive time frame, so we would support any kind of delay to ensure there's better analysis, to make sure that we have a fully developed solution and we know what the results are going to be," he said. "If we end up … mostly just compensating existing generators for doing what they're already doing, we'll see significantly higher costs without much benefit. I think that's a very real risk with this proposal."

— Phil Bartlett, chairman of the Maine Public Utilities Commission

"We think this is a very aggressive time frame, so we would support any kind of delay to ensure there's better analysis, to make sure that we have a fully developed solution and we know what the results are going to be," he said. "If we end up … mostly just compensating existing generators for doing what they're already doing, we'll see significantly higher costs without much benefit. I think that's a very real risk with this proposal."

Liz Delaney, director of energy market policy for the Environmental Defense Fund, raised a similar concern. "While the ISO has made efforts to justify its targets and to tie them to NERC standards, it's still unclear if this target is calibrated with enough precision to ensure that it's procuring essential and not excessive quantities. ISO New England has not assessed whether a more modest procurement would still uphold the NERC standards."

David Cavanaugh, vice president of regulatory and market affairs for Energy New England, said NEPOOL's publicly owned utilities sector is not convinced the M-DAM is needed. "The M-DAM significantly complicates the design and implementation and would increase the cost of business for publicly owned entity members through increased IT requirements and staff with yet-to-be-determined benefits," he said.


Katie Dykes, Connecticut DEEP

Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection, said regulators have been chastened by previous market overhauls touted as fixes, such as the Pay-for-Performance capacity market program.

She noted that the RTO is proposing not just three new ancillary services markets, but also the M-DAM and a new futures market. "With all of these new markets, we know that they will raise costs. The questions that we're not prepared today to be able to address is whether they will solve the problem and whether they will solve the problem fully."

Penalties or Incentives?


Richard Glick, FERC | *© RTO Insider*

FERC Commissioner Richard Glick, who attended part of the hearing, also cited the incentives in the PfP program in expressing skepticism over the ESI plan. He questioned whether the RTO should be using a "carrot or stick" approach.

"There was an expectation that resources were going to firm up their fuel supply arrangements ... and I understand that didn't really occur," Glick said. "Is this something we should be solving ... with incentives or should we be providing penalties?"

"Whether it's structured as an incentive or penalty, what it really comes down to in influencing the commercial decisions of entities ... is the delta in their profit and loss if they take [action] or they don't," ISO-NE's White responded. "I don't look at it as there's a fork in the road [where] you can create incentives or penalties. I think that's not the most constructive way to approach it."

"We believe the forward market is the critical piece. Not the spot market."

— Brett Kruse, vice president of market design for Calpine

Massachusetts DPU Chair Nelson said he worries "that a stick approach might spur on more [plant] retirements."

But James Daly, vice president of energy supply for Eversource Energy, said prior markets mechanisms have failed to deliver needed infrastructure. "FERC should require ISO-NE to make fuel assurance mandatory and not an option," he said.

OSW, LNG Ignored?

David Ismay, senior attorney for the Conservation Law Foundation, said the proposal underestimates the contribution of state-sponsored clean energy resources to winter reliability.

The "ISO confirmed that, had it been operating at the time, the 800 MW of offshore wind that will be brought online in the next few years for Massachusetts would have had significant energy security and cost benefits during a representative cold snap [such as] one that we experienced in the 2017-18 winter," he said.

White said the RTO has done some modeling of prospective offshore wind. "The challenge, of course, is that it is prospective. There is only the one very small facility [operating currently]," he said, referring to the 30-MW Block Island Wind Farm. "It's difficult to reliably simulate the potential variability when there isn't enough data to go on."

Brett Kruse, vice president of market design for Calpine, said the RTO's decision to sign Exelon's Mystic generating plant to out-of-market contracts for Forward Capacity Auction 14 assumed there would be no LNG imports to the Northeast Gateway Deepwater Port Facility, which his company has used to supply its 2,000 MW of gas-fired generation in the region.

"We certainly believed that we could enter into similar agreements for the delivery years for FCA 13 and 14. In fact, we believe that many other alternatives (including additional oil backup) would have been available to ISO-NE at less than half the cost of the Mystic contract, if only ISO-NE would have opened their fuel security efforts to competition," he said.

Other Proposals

Kruse and several other witnesses also offered alternatives to the RTO's proposal.

Calpine proposed procuring fuel-secure megawatt-hours for the winter months three years in advance, a proposal it called the "forward enhanced reserves market."

"We believe the forward market is the critical piece. Not the spot market," Kruse said.

Neal Fitch, senior director of regulatory affairs for NRG Energy, said a seasonal forward market that incented purchases of oil and LNG four to six months ahead of real time would be most effective. But he said it will come with a cost. "Revenue-neutral solutions are really no solution at all," he said.

ISO-NE's Parent said the RTO will begin outlining its forward market proposal to stakeholders in August, but it won't be included in its October filing. "Forward markets require sound spot markets. … to design a forward market in the absence of understanding how the spot market works is premature," he said.

Tom Kaslow, vice president of market policy for FirstLight Power Resources, proposed the RTO limit the qualified capacity of gas-only resources in winter "to the level of such generation that the ISO-NE analysis indicates can be simultaneously fueled."

"Qualifying a higher level doesn't give you any more" capacity, he said. ■

"Revenue-neutral solutions are really no solution at all."

— Neal Fitch, senior director of regulatory affairs for NRG Energy

ISO-NE News

ISO-NE Tweaks Inputs for FCA 14 Fuel Security Analysis

By Michael Kuser

ISO-NE advised FERC on Friday that it is revising its fuel security analysis for Forward Capacity Auction 14 to assume more natural gas use and bigger contributions from renewables.

The RTO made the disclosure in its first annual informational *filing* comparing actual winter conditions with the triggers, assumptions and scenarios it used in the fuel security analysis.

The filing was required by the commission's December 2018 order (*ER18-2364*) accepting the fuel security evaluations the RTO will perform to assess whether resources submitting retirement bids are needed during stressed winter conditions. The evaluations were approved as an interim measure for FCAs 13, 14 and 15 until the RTO can implement market-based mechanisms to address its fuel security challenges. (See *ISO-NE Fuel Security Measures Approved*.)

The commission required the filings in recognition that the fuel security study "is a newly developed process, is based upon a number of assumptions and is not addressed by the NERC reliability standards. As ISO-NE gains additional information and experience, we expect that the study assumptions, methods, scenarios and triggers may need to be further refined and updated."

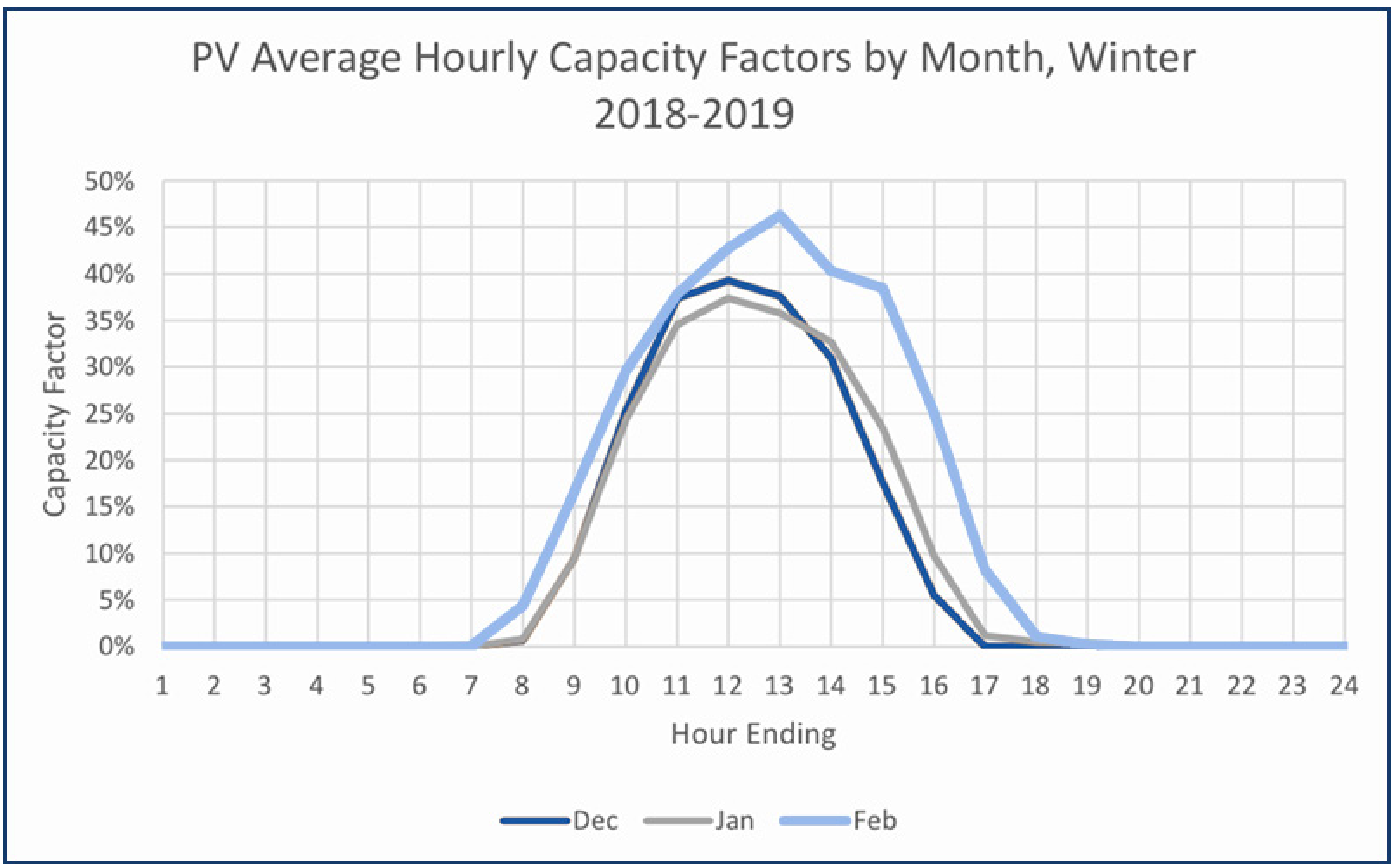
The initial analysis compares the assumptions used in FCA 13 — conducted in February for the 2022/23 delivery year — with winter 2018/19.

However, ISO-NE said it is not prudent to draw significant conclusions about its review methodology from last winter because it was very mild in comparison to the severe winter of 2014/15 used to develop the modeling assumptions.

The RTO nonetheless said it will adopt several revisions for FCA 14, based on input from the NEPOOL Reliability and Participants committees. (See *NEPOOL MC Debates Energy Security Models*.)

"Broadly speaking, these refinements increase the amount of natural gas and fuel oil that is modeled in the analysis, and further increase the capacity values of certain renewable resources. Collectively, these revisions tend to move the analysis in a less conservative direction," the filing said.

RTO officials and other stakeholders participated in a public meeting with FERC staff on Monday on efforts to develop market-based mechanisms to ensure fuel security (*EL18-182*, *et. al.*). (See related story *FERC Staff Hear Doubts on ISO-NE Fuel Security Plan*.) ■



PV average hourly capacity factors | *ISO-NE*

ISO-NE News

NEPOOL Market Committee Briefs

Using Solar Data to Forecast Power Production

The New England Power Pool Markets Committee on July 8 voted to recommend that the Participants Committee support ISO-NE Tariff revisions requiring solar resources to provide meteorological and operational data to support power production forecasting. One member from the Supplier Sector abstained.

The changes would also consolidate wind and solar data requirements within Market Rule 1 of the Tariff, as proposed by ISO-NE.

Analyst Jonathan Lowell *presented* the RTO's case for the advisory vote on wind and solar data requirements in the large generator interconnection agreement. The RTO anticipates changes to Market Rule 1 to become effective no earlier than December.

The NEPOOL Transmission Committee at its June 13 meeting supported related changes to remove the existing wind data requirements from the LGIA, and the Participating Transmission Owners Administrative Committee will review and vote on the changes when it meets Sept. 24.

Easing Import Resource Transactions

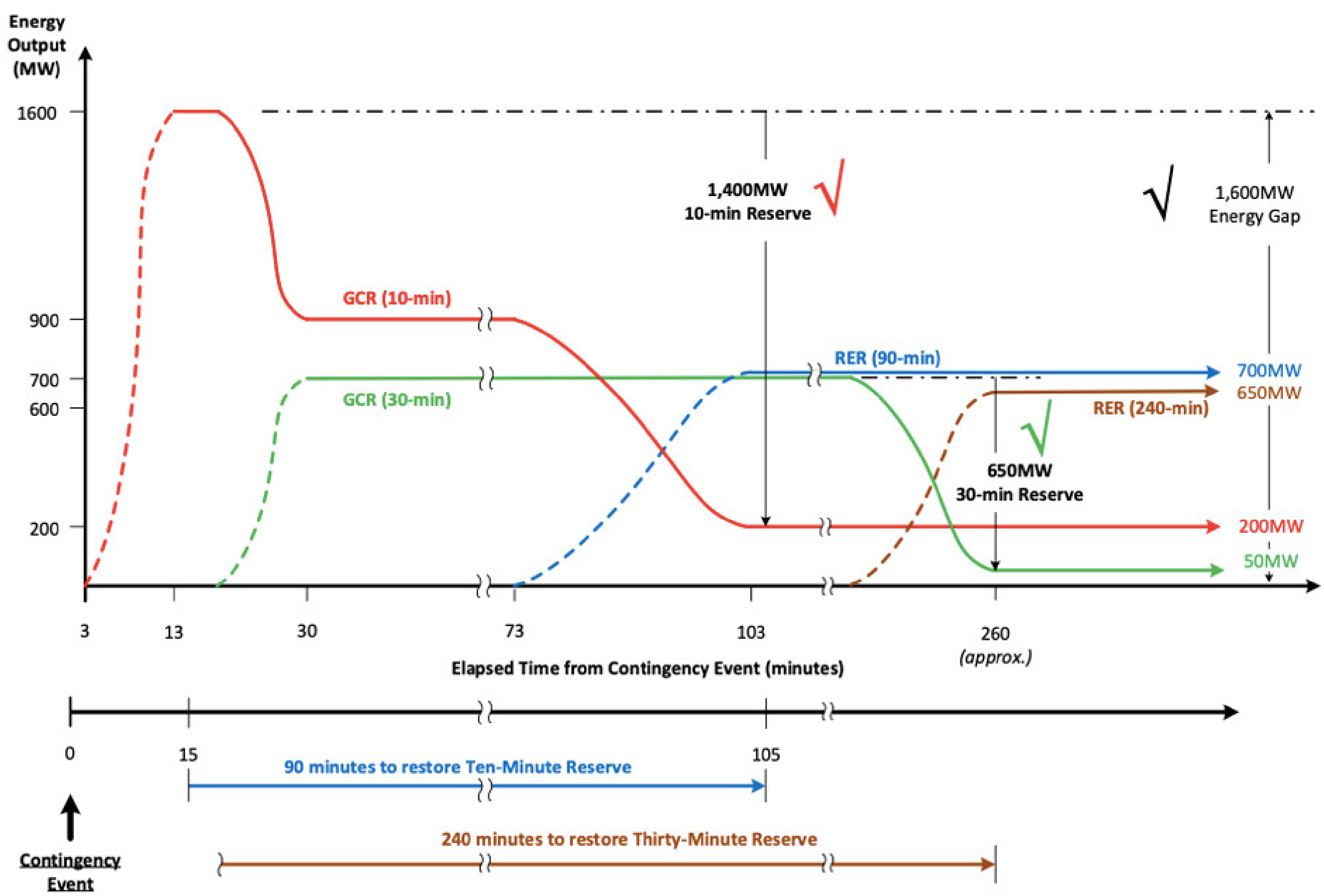
The MC also voted to recommend that the PC support revisions to Market Rule 1, Manual M-11 and Operating Procedure No. 9 to simplify external transaction submittal requirements for capacity import transactions and to remove outdated Tariff provisions, as proposed by the RTO.

The motion passed based on a show of hands, with one opposed and two abstentions from the Supplier Sector, one opposed and three abstentions from the Generation Sector, one opposed and three abstentions from the Alternative Resources Sector, and two opposed from the End User Sector.

RTO staffer Matthew Brewster *presented* the proposed Market Rule 1 revisions, which would streamline the requirements for submitting external transactions associated with import capacity resources and better align the requirements with Pay-for-Performance rules. They also include clean-ups to remove outdated provisions relating to coordinated transaction scheduling and dynamic scheduling.

The updates were motivated by the technical project to replace the software platform for submitting external transactions, which is scheduled for implementation by October.

In voting against the motion, Brett Kruse of Calpine said that imports that count as capacity should be from a specific generating



The RTO used a dashed line for the ramping of replacement energy reserves (RER) and generation contingency reserves (GCR) because it does not know their ramp pattern, but it does know where it should be at the end of 10 or 30 minutes. | *ISO-NE*

ISO-NE News

resource that owns point-to-point firm transmission, ensuring the import is treated the same as internal capacity and not exposed to external curtailment.

"Otherwise, I believe that this is a very liberal interpretation of 'capacity,'" Kruse said.

Assessing ESI Impacts

Todd Schatzki of Analysis Group presented preliminary results of his firm's *assessment* of the impacts of the RTO's proposed energy security improvements (ESI).

The proposed changes potentially affect market participant resource decisions and economic offers in ways that improve energy security, he said, including by creating incentives for resources to secure fuel inventory to merit an ESI award.

The study will run two scenarios: one a business-as-usual (BAU) case and another that assumes both the presence of ESI market products and some change in the actions resources take to ensure they have inventory to meet an energy commitment, Schatzki said. The differences between the two model runs will provide an estimate of impacts.

Analysis Group will assume that ESI will incentivize generators to obtain a sufficient number of LNG forward contracts to utilize all available pipeline transport capacity, he said.

The firm will return to the committee July 30 to present further preliminary results, including comparison between future BAU and ESI scenarios. In August, it will present preliminary scenario results and respond to stakeholder feedback, and then present a draft report in September ahead of an October filing.

ISO-NE market development economist Chris Geissler presented the RTO's *analysis* of ESI impacts on entry/exit decisions and Forward Capacity Auction outcomes.

Geissler said the RTO expects the introduction of ESI to push the resource mix in a way that improves energy security, but that various factors would influence the magnitude of that effect and the impact on FCA prices, including the extent to which resources that are marginal or nearly marginal under BAU increase or decrease their FCA bid prices under ESI; the degree to which resources that sell capacity under ESI provide more energy security than those they displace; and resource intermittency.

ESI could reduce the likelihood and size of positive real-time price spikes that may otherwise occur because of limited available energy, while the costs of taking actions to improve energy security (such as storing more fuel oil) are netted against incremental revenues.

Geissler highlighted that there could be many mechanisms by which ESI is likely to affect net revenues.

ESI Conceptual Design

The MC spent the second day of its meeting discussing ESI conceptual design elements as *presented* by ISO-NE Principal Analyst Andrew Gillespie and Lead Analyst Ben Ewing.

The RTO is continuing to assess approaches to mitigation, and detailed mitigation rules will be part of related efforts in 2020, subject to FERC approval of the core ESI design filing in October, Gillespie said.

An Internal Market Monitor *memo* supplied by David Naughton said that the Monitor understood that participation in the day-ahead market for ESI products will be voluntary.

The Monitor tried to strike a balanced tone in the memo, neither for nor against voluntary participation. It noted that a voluntary market will allow physical withholding, a substitute for exercising market power through economic withholding. The RTO may need to address physical withholding with *ex ante* market rules, which would be preferable to using claw-back mechanisms, Naughton said.

Speaking on the RTO's proposed multi-day-ahead market (MDAM), Ewing said it would use the same standard settlement logic of deviations used to settle the real-time energy market today.

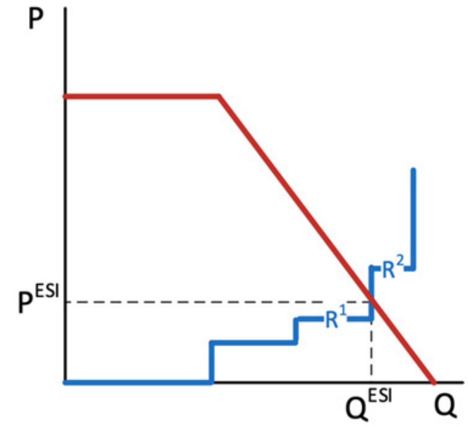
A forecast energy requirement price (FERP) settlement quantity will be paid to all resources meeting the forecast energy requirement on the prompt day, Ewing said, adding that the FERP is paid to a resource's full energy position on the prompt day and is not a deviation settlement.

The RTO will further address the relative benefits of MDAM and the single-day-ahead market (SDAM) with opportunity cost bidding at the August MC meeting.

Stakeholder Concepts

The MC on Wednesday heard and discussed stakeholder concepts to enhance energy security from NextEra Energy Resources, Calpine, FirstLight and Energy Market Advisors.

Michelle Gardner and Sam Newell of Brattle Group presented *NextEra*'s concept for strategic operating reserves, a physical reserve held by ISO-NE as backup to protect against adverse conditions, consistent with reliability objectives.



This example shows the Forward Capacity Market clearing under proposed energy security improvements (ESI). Resource 1, which contributes more significantly to energy security, reduces its price to reflect additional net revenues it expects under ESI. ISO-NE awards it a capacity supply obligation over the more expensive, less secure Resource 2, which expects no ESI revenue. | *ISO-NE*

New products to be purchased by ISO-NE in the day-ahead market would include replacement energy reserves and generation contingency reserves. (See "NextEra: Reserve Products," *NEPOOL MC Debates Energy Security Models*.)

NextEra continues to evaluate the RTO's proposal and still feels strongly that it doesn't quite hit the mark — but emphasizes that it must see the benefits, Gardner said. Under NextEra's proposal, units can have up to 12 hours notification time for deployment, and unlike traditional reserves, these units are valued because of their security, not because they are fast-start units.

Rebecca Hunter, senior analyst for government and regulatory affairs, delivered *Calpine*'s longstanding case for a forward enhanced reserves market (FERM) to retain resources at risk of retirement.

Calpine proposes that suppliers bid at auction for a total minimum or maximum amount of megawatt-hours they will commit to offer from stored fuel during an *Operating Procedure 21*, activated when the RTO declares an energy emergency event. (See "Calpine: More Precise; More Cautious," *NEPOOL MC Debates Energy Security Models*.)

Hunter said the design changes and updates since June included making clear that natural

ISO-NE News

gas resources would only qualify for FERM with firm transportation and a gas supply contract.

Calpine is also considering removing the cap for the eligible amount of megawatt-hours and establishing a floor to manage varying starting fuel inventory levels.

Tom Kaslow presented the *FirstLight* concept, which argues that the RTO can avoid sending inaccurate market signals at times when winter capacity is actually not in surplus by assuring that each procured megawatt can be fueled. (See "FirstLight: Filling Buckets," *NEPOOL MC Debates Energy Security Models*.)

Mass. Attorney General Update

Christina Belew of the Massachusetts attorney general's office quickly updated the MC on its *proposal* prepared by London Economics that recommends a simple auction format of sealed bids with a uniform clearing price. (See "Massachusetts AG: Simpler, More Physical," *NEPOOL MC Debates Energy Security Models*.)

Belew said her office was still fleshing out the design details of its forward stored energy reserve proposal and that she may be back to present additional information at the August MC meeting.

Enhanced Storage Participation

ISO-NE Principal Market Development Analyst Catherine McDonough led a *presentation* and discussion of the RTO's proposed manual revisions consisting of conforming changes to support implementation of the enhanced storage participation and FERC Order 841 compliance projects.

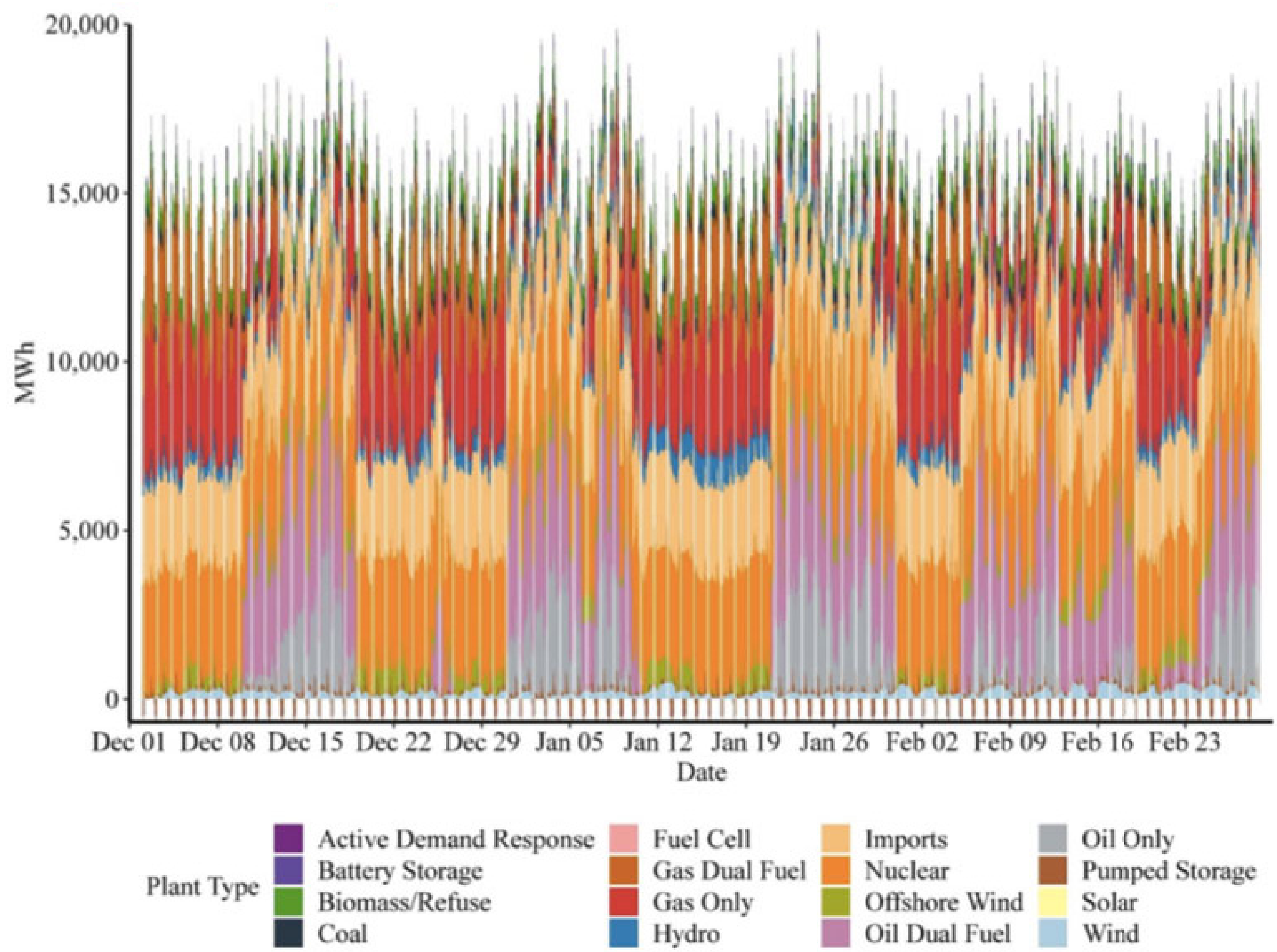
The proposed manual revisions reflect two sets of Tariff changes: the enhanced storage participation changes, which became effective on April 1, and additional Order 841 compliance changes, which will become effective on Dec. 3, pending FERC approval.

The proposed manual revisions also include changes to address a stakeholder concern from the June MC meeting about how the maximum discharge limit of an electric storage facility is set when it has less than one hour of available energy, which McDonough said she expects to become effective March 1, 2020.

Other proposed manual changes since last month include adding conforming and clean-up changes to Definitions and Abbreviations, conforming changes to Regulation Market, and clean-up changes to Registration and Performance Auditing.

Stakeholders said they wanted to focus on increasing the dynamic change function of the grid, so that a storage resource switching to charging is not necessarily cut off from being a source of power if the situation changes in five minutes, for example. ■

— Michael Kuser



Projected hourly winter day-ahead generation positions for 2025/26 under the high severity business-as-usual scenario | *Analysis Group*

MISO News

Monitor Splits with MISO on Summer Readiness Estimates

By Amanda Durish Cook

CARMEL, Ind. — MISO's Independent Market Monitor has a different opinion of the RTO's summer supply picture three weeks into the season.

Although MISO predicts a 70% chance that it will declare an emergency to call on load-modifying resources (LMRs) this summer, it said its base case shows a 19% reserve margin, with 149 GW of resources on hand to cover a 125-GW projected peak. Its planning reserve margin is 16.8%. (See *MISO Foresees Summer Emergency, LMR Use*.)

But Monitor David Patton said that while his base case of MISO's capacity picture also shows a more than 2% excess beyond the planning reserve margin, a more realistic *scenario* including outages shows a 12.2% margin and an even lower 8.3% margin when accounting for resources that are unavailable to cover emergencies because of their long notification times.

Patton first shared his concerns at the June Board Week in Traverse City, Mich. (See *Emergencies Prompt MISO to Re-examine LMR Protocols*.) He expanded on them during a Market Subcommittee meeting Thursday, saying, "The way in which we calculate these margins aren't as accurate as they could be."

David Patton, Potomac Economics | © *RTO Insider*

Patton said some hot, high-demand days this summer show margins dipping as low as 2%.

"These margins would raise concerns for some RTOs, but MISO has the unique advantage of having huge import capacity in many directions. … It's a powerful shock absorber in terms of reliability," Patton said.

"Our intention is not to scare anybody," he added, saying he would be concerned if MISO's footprint were more isolated, like New York's or New England's.

MISO staff said that while they don't dispute the results of the Monitor's analysis, they haven't calculated their own additional summer scenarios to compare against it. However, they pointed out that their base case calculations and the Monitor's were about equivalent.

Patton has called for changes to "an accumulation of rules that aren't optimal." He said MISO should carry reserves on the regional dispatch transfer limit on transmission between MISO Midwest and South to temper regional emergency conditions. The suggestion is one of Patton's State of the Market recommendations this year. (See *MISO Monitor Poses 6 New Market Recommendations*.)

"It'd be a win-win for the joint parties and MISO," Patton said. The joint parties are neighboring transmission systems Southern Co., Tennessee Valley Authority, Associated Electric Cooperative Inc., Louisville Gas and Electric, Kentucky Utilities and PowerSouth Energy Cooperative.

Patton wants more transparency around MISO's decision-making when emergencies are declared and clearer emergency declaration protocols.

"These regional emergencies just began at the end of 2017, beginning of 2018. So, you have [control room] operators exercising a lot of discretion. It's important to think about what triggers these emergencies," Patton said.

"There's nothing written down on what they're supposed to be doing and how they're supposed to be weighing these factors. … It should be clear how those factors should be weighed and processed. … We should write down what these triggers are."

But he also praised MISO operators for taking relatively few out-of-market actions when compared to other RTOs/ISOs. MISO appropriately keeps its out-of-market actions confined to emergency situations, Patton said.

Extended Outages and the Capacity Auction

Patton has continued his criticism of MISO's capacity auction availability requirements, which he said are too generous.

"We approved and cleared a unit that's going to be on planned outage for the entire planning year," Patton said at the June Market Subcommittee meeting, referring to a large generator in Michigan. MISO as a rule does not divulge which generators have taken outages.

"We've seen a number of units cleared that won't be available over the summer peak" over multiple auctions, Patton continued at last week's meeting.

Had MISO not counted the Michigan generator on extended outage as available in the 2019/20 planning year, Patton said, Michigan's Zone 7 would have cleared near the $240/MW-day cost of new entry.

"That $24/MW-day is not representative," Patton said of Zone 7's auction actual clearing price. (See *Most MISO Zones Clear at $3/MW-day in 2019/20 PRA*.)

"Zone 7, as we sit here right now, is incapable of meeting its local clearing requirement," argued the Coalition of Midwest Power Producers' Mark Volpe at Wednesday's Resource Adequacy Subcommittee meeting. He said MISO should immediately work with stakeholders to remedy the situation by creating some availability requirements.

"This is about reliability," Volpe argued. "Resource adequacy in MISO is broken. This should not be permitted to persist."

MISO Director of Resource Adequacy Coordination Laura Rauch said any new availability requirements should be worked through carefully to avoid unintended consequences.

RASC Chair Chris Plante said "it doesn't seem right" for MISO to fully accredit a resource that's on a planned outage for the entire year.

"We completely agree in concept; we're looking at the potential unintended impacts [of a solution] and how likely it is this will occur again in the next planning year," Rauch said.

MISO staff said they will provide the RASC a timeline for when new availability requirements could be implemented. ■

MISO News

Mich. PSC Urges Changes After Winter Emergency

By Amanda Durish Cook

Michigan regulators are calling on the state's gas and electric utilities to step up measures to head off supply emergencies like the one that arose this past winter during a deep freeze.

While a draft *report* released by the Michigan Public Service Commission on July 1 determined that the state's energy systems are adequate to meet customer needs, it also urged utilities to undertake a raft of improvements to address extreme weather events, security threats and the expanded use of renewable energy sources.

Gov. Gretchen Whitmer ordered the statewide energy assessment after a polar vortex struck the state Jan. 30-31. During the event, both Consumers Energy and DTE Energy issued public appeals for conservation, while Whitmer appeared on video via social media to ask ratepayers to lower thermostats or risk a gas shortage. Consumers' gas scarcity was compounded by a fire at Ray Compressor Station near Detroit. (See "Gas Shortage Warnings," *MISO Maintains Reliability Through Arctic Midwest Temps*.)

"Despite the positive outcome, the events of Jan. 30 and 31 raised significant concerns about whether Michigan's energy systems can reliably produce and deliver energy to all Michiganders as extreme weather events increase," the PSC said.

The agency was asked to evaluate whether the design of electric, natural gas and propane delivery systems are "adequate to account for operational problems, changing conditions and extreme weather events" (*U-20464*). The 231-page report makes 36 recommendations within the commission's jurisdiction and 14 "observations" outside the scope of its jurisdiction.

Among its major recommendations, the PSC said utilities should:

- Incorporate five-year-ahead distribution and transmission plans into the *integrated resource plans* required by the state. The commission said the move would "ensure truly integrated electricity system planning" and could expand electrical connections between Michigan's peninsulas and neighboring states. It said an expanded ability to import electricity could address short- and long-term reliability issues.
- Undertake "long-term, risk-based" natural gas infrastructure and maintenance planning. It also recommended natural gas utilities include equipment and facility outages in risk models and better plan for transmission contingencies.
- Make more careful retrofitting, retirement and new power plant build decisions. The agency said utilities should work with stakeholders "to understand the value of resource supply diversity" and not rely so heavily on traditional planning and financial analyses. Utilities should "propose a methodology to quantify the value of generation diversity in integrated resource plans."
- Re-examine natural gas utility curtailment procedures to make sure they "prioritize home heating over electric generation."
- Improve electric demand response programs "since some customers did not respond as expected during the polar vortex, and utility tariffs were inconsistent." The PSC said natural gas utilities should also work to create DR programs "as an alternative to broad emergency appeals." Utilities should also review their communication protocols with customers during DR events.
- Create rules for cybersecurity and incident reporting for natural gas utilities and improve energy system cybersecurity in general. The PSC suggested utilities undertake regular IT audits, simulated phishing campaigns, multifactor authentication for remote access and cybersecurity performance assessments.
- Develop standardized communications with the commission for electric and natural gas emergency events.
- Expand use of emergency drills "to provide a range of scenarios besides outage management and restoration." The PSC said utilities should also test curtailment and DR events. "Communication related to the Ray event and the polar vortex was confusing, inconsistent and erratic," it concluded.
- Improve communications and data sharing in general between electric utilities, PSC staff and RTOs to ensure that the "RTOs will have the information needed to plan and operate the electric system to accommodate an increasing amount of distributed energy resources."

"Overall, the energy system is strong but would benefit from increased resilience, strengthened infrastructure interconnections

Consumers Energy linemen in winter | *Consumers Energy*

and improved communication," PSC Chairman Sally Talberg said.

The PSC also found that MISO should enact a seasonal capacity auction, "more carefully consider" non-transmission alternatives prior to approving transmission projects and speed up its generator interconnection queue — although those items are outside of the regulator's purview.

The commission also found that Michigan statue limits the PSC in assessing "meaningful penalties" for utilities that are not in compliance with the Michigan Gas Safety Standards. "This may impact the health, safety and welfare of Michigan residents," the PSC said.

The commission formed five work groups — focusing on electricity, natural gas, propane, cyber and physical security, and energy emergency management — and hosted more than 40 internal and external meetings to create the initial report.

After a public comment period, the commission will deliver a final report to Gov. Whitmer by Sept. 13. The commission could then order utilities to take steps to improve their energy supply and delivery processes.

"Moving forward, this report will help to inform our next steps in assuring all Michiganders have reliable access to energy when they need it at home, at school and at work. With the transition to more renewable energy resources and the growing impact of climate change, it is imperative that our utility infrastructure can meet the changing demands while keeping rates affordable and protecting the environment," Whitmer said in a *press release*.

In its latest resource adequacy survey, the Organization of MISO States identified Michigan's Lower Peninsula as one of three MISO areas that could soon experience supply shortages, with a potential 0.9-GW shortage as early as 2020. (See *Supply Future Brighter, OMS-MISO Survey Shows*.) ■

MISO News

MISO Market Subcommittee Briefs

MISO Eyeing 6-Day Margin Forecast

MISO is now aiming for a six-day horizon for its new, comprehensive multiday operating margin forecast.

"Our plan is to roll this out incrementally," said Chuck Hansen, of MISO's market design team.

The first iteration of the forecast will look ahead six days, be updated once daily and estimate a daily peak hour on the systemwide, MISO Midwest and MISO South levels. Future versions of the forecast may contain multiday hourly load and wind forecasts, behind-the-meter generation forecasts, interchange forecasts and data on emergency resources.

Hansen said the idea is to build a "data warehouse" and flexible analytical platform so that MISO can easily add new sources of information for a more nuanced forecast.

"We want to be able to change the report without starting from scratch," Hansen said.

MISO introduced the concept last month, although it offered few specifics on what the forecasting would entail. (See *MISO Adding Week-ahead Forecasts*.) The new forecast will be purely informational for market participants and won't be tied to financial commitments.

Since last month, MISO has analyzed more than five years' worth of its systemwide load and wind generation forecasting and found it has been "generally accurate," Hansen said.

He said he would return to the Market Subcommittee in August with more details and a more precise timeline on the project.

Short-term Reserve Filing Coming Shortly

MISO will file with FERC in mid-August a proposal to create a short-term reserve product, staff told the Market Subcommittee.

The RTO said it hopes to roll out the *product* in mid-2021, supported by a soon-to-be-replaced market platform. It also plans a post-implementation review in 2023 to gauge the product's performance and delivered cost savings.

Based on simulations, MISO expects the reserves to *deliver* an estimated $5 million in net annual production benefits and a $1.6 million reduction in annual revenue sufficiency guarantee payments.

After stakeholders questioned the analysis behind the $5 million savings, staff said the RTO performed a rough estimate of the benefits based on the best available information.

The product will be designed to furnish capacity within 30 minutes. MISO expects it will help better manage the regional directional transfer limit and help local areas that lack available and flexible resources, especially in southeastern Louisiana in Zone 6 and East Texas in Zone 7, both of which have local reliability issues. (See *MISO Prototyping Short-term Reserve Product*.)

MISO has set a $100/MW market-wide demand curve for the reserves, so the market is designed to naturally clear energy before it clears the reserve product. The product will be subject to monitoring for physical and economic withholding just like ancillary services, with mitigation measures only applied in constrained regions and zones, not market-wide. Offers below $10/MWh will be excluded from economic withholding monitoring. ■

— Amanda Durish Cook

MISO Resource Adequacy Subcommittee Briefs

MISO Monitor to Cut Back on BTMG Monitoring

CARMEL, Ind. — MISO's Independent Market Monitor intends to reduce its monitoring of physical withholding by small behind-the-meter generators in the footprint.

Most of MISO's BTMGs are about 2 MW, and the Monitor is proposing only *monitoring* for physical withholding by units of at least 10 MW. It would still not recommend enforcement action for any possible economic withholding from BTMGs.

"Excluding these resources will improve efficiency, allowing for more focus on resources that may have market power," the Monitor explained.

IMM staffer Michael Chiasson told the Resource Adequacy Subcommittee on Wednesday that he would only scrutinize aggregated nodes of BTMG for physical withholding if one of those groups contained a generator larger than 10 MW. Groups that contain multiple smaller generators that exceed 10 MW combined would still be left alone.

According to the Monitor's count, MISO contains 826 BTMGs, with 547 of those serving as load-modifying resources. BTMG comprises just 5,089 MW of MISO's Generation Verification Test Capacity and 4,582 MW of unforced capacity.

Minnesota Public Utilities Commission staff member Hwikwom Ham asked if the Monitor foresees large groups of small BTMGs exercising market power.

"We still think that they're unlikely to have market power," Chiasson said. "If we do see something that's alarming, that doesn't prevent us from taking action and filing a recommendation with FERC. Our hands really aren't tied here."

"Is this in the spirit of [ERCOT's philosophy that] 'small fish swim free?'" MISO's Michael Robinson asked.

Chiasson said he wasn't familiar with ERCOT's controversial *protections* for small generators that control less than 5% of the Texas wholesale energy market. Such generators are dubbed too small to hold market power and are exempt from penalties for market power abuse.

"The small fish can be pivotal in certain circumstances," Customized Energy Solutions' David Sapper said.


Michael Chiasson, Potomac Economics | © *RTO Insider*

MISO staff said that if supplies ever became so scarce that small BTMGs become pivotal suppliers and rake in higher prices, they would deserve the high compensation for providing a critical service.

Staff said the new BTMG physical withholding rule would likely be included in a monitoring rule update filed at FERC before fall.

Additionally, the Monitor plans to add default technology-specific avoidable costs for solar generation and battery storage at $64.11/MW-day and $109.59/MW-day, respectively.

Most of MISO's capacity market participants elect to use the Monitor's default avoidable costs, saving time and effort rather than calculating and documenting individual refence levels for generation. The Monitor relies on the same values PJM currently uses, although PJM does not maintain values for solar and storage.

MISO Reviews OMS Survey

MISO staff took time to reassess with stakeholders the results of last month's annual Organization of MISO States resource adequacy survey.

The survey forecasts a generation surplus of about 3 to 6 GW in 2020, about 1 to 4 GW in 2021 and about 1 to 3.4 GW in 2022. The range of possibilities in 2023 and 2024 varies the most, with the forecast indicating anything from a 1.3-GW shortfall to a 7-GW surplus in 2023, and a 2.3-GW shortfall to another 7-GW surplus in 2024. This is the sixth iteration of the survey. Last year's forecasted a possible 0.1-GW shortfall in 2020. (See *Supply Future Brighter, OMS-MISO Survey Shows*.)

"Quite a few resources have firmed up their availability over the last year," MISO's Stuart Hansen said. "We're resource-sufficient for the next three years. It's 2023 and 2024 when we may have a problem area."

But Hansen said that even in those years MISO by no means has a guaranteed adequacy risk. He said changes in load and new resource additions from the approximately 100-GW interconnection queue could come online and mitigate possible shortfalls.

"Every single year, we're going to see this change," he said, adding that 2020 "looked bad" from last year's perspective but has since become "3 GW long."

MISO is circulating survey results with state public service commissions in its footprint.

"I'm not too concerned," Hansen said of forecasted potential deficits. "This survey is a tool to open dialogues with state commissions [and] utilities."

The Coalition of Midwest Power Producers' Mark Volpe asked why MISO is initiating outreach on the survey with state commissions when it is market participants that respond.

Hansen said the RTO is simply ensuring states are aware of the survey's resource adequacy results. He said MISO does not cross-check survey results against states' integrated resource plans.

Volpe also asked if MISO may recalibrate survey results based on new public announcements regarding retirements and new plant construction.

"We may look at that, but we do have a cutoff period. At some point, those would become part of the 2020 survey. If you're asking if we would open it up now, probably not," Hansen said.

But Hansen reassured stakeholders that the survey results include the Illinois Pollution Control Board's June 20 *announcement* of the retirement of 2 GW of coal-burning generation in the state. Southern Illinois' Zone 4 is one of three local resource zones in MISO that could experience capacity shortfalls from 2020 to 2024. ■

— Amanda Durish Cook

MISO News

Solar Developer Takes on We Energies

By Amanda Durish Cook

The head of a small Iowa solar developer is prepping for a second state supreme court battle over his ability to supply electricity in a state without retail choice — after winning a similar fight in his home state.

Dubuque-based *Eagle Point Solar* is suing the Wisconsin Public Service Commission and We Energies to compel the utility to connect its planned, third-party rooftop solar projects for the city of Milwaukee (*30701*). The lawsuit may also clarify rules on what constitutes a public utility in the state.

Barry Shear, Eagle Point Solar | *Eagle Point Solar*

Eagle Point CEO Barry Shear wants solar developers to be able to own projects that generate electricity for individual customers in a regulated utility's footprint. The lawsuit cites WE's refusal to honor Eagle Point's services agreement with Milwaukee to install 1.1 MW worth of solar generation on seven city-owned buildings: three libraries, two public works buildings, a police station and a garage. WE refused to connect the solar projects at the distribution level, claiming sole domain over Milwaukee as an electric customer.

"We Energies is saying that a [power purchase agreement] is nothing but selling energy in their service territories. … Their position is it's an illegal transaction even though there's no law against it," Shear said in an interview with *RTO Insider*.

Eagle Point filed the suit in Dane County Circuit Court in late May after the Wisconsin PSC voted 2-1 against hearing the matter. The commission said the dispute was better left to the state's legislature because it triggered questions about what defines a utility. Eagle Point filed an unsuccessful appeal with the PSC in the spring.

As of July 9, WE had not filed its response to the suit.

The agreement would have divided project ownership 80% to Eagle Point and 20% to the city, with the option for the city to purchase the full project over time. Milwaukee has since pared down the solar project to three buildings that it will self-finance, though Eagle Point could still strike a deal on the remaining buildings.

Renewable energy tax credits, like the 30% investment tax credit, are inaccessible to nonprofits and cities such as Milwaukee, which instead rely on third-party providers to attain passed-through savings.

Eagle Point has completed more than 700 solar installations totaling 17 MW. Fighting for access to a regulated utility's territory isn't new turf for Shear, who prevailed at the Iowa Supreme Court in a similar 2014 *conflict* with Alliant Energy.

While 26 states explicitly allow third-party solar PPAs, Wisconsin is one of 15 states that have not clarified whether they allow such third-party solar arrangements, according to the North Carolina Clean Energy Technology Center.

Utility Defined?

The case could force that clarification in Wisconsin — and a more strongly defined concept of a "public utility."

But WE spokesperson Brendan Conway said the law is already clear — entities cannot sell electricity to WE customers without first registering as a public utility.

"In Eagle Point's case, because we already provide retail electric service to the city, Wisconsin law prohibits Eagle Point from doing so. Not only is the agreement illegal, it shifts costs to customers who are paying for the infrastructure that provides service when needed and would allow some customers to benefit from our system without paying for a portion of it," Conway said in an emailed statement to *RTO Insider*.

| *Renew Wisconsin*

"There is no requirement under Wisconsin law that Wisconsin Electric interconnect the facilities owned by a third party who intends to provide electric service to a retail customer already served by Wisconsin Electric," We Energies argued in the PSC case in December, referring to its electric subsidiary, Wisconsin Electric Power. (The utility also provides gas service as Wisconsin Gas.)

The Sierra Club has long *encouraged* Wisconsin to clear up energy law so that third-party PPAs are explicitly allowed. The move would help expand clean and renewable energy use, the nonprofit claims.

100-Year-plus Case Law

Eagle Point acknowledges that only "public utilities" can sell power to the general public but claims it's perfectly legal for it to generate for a "restricted class" of customer.

CEO Shear is drawing on Wisconsin law and a 1911 case in which a landlord built an exclusive steam plant for tenants' and neighbors' use and was not deemed a public utility.

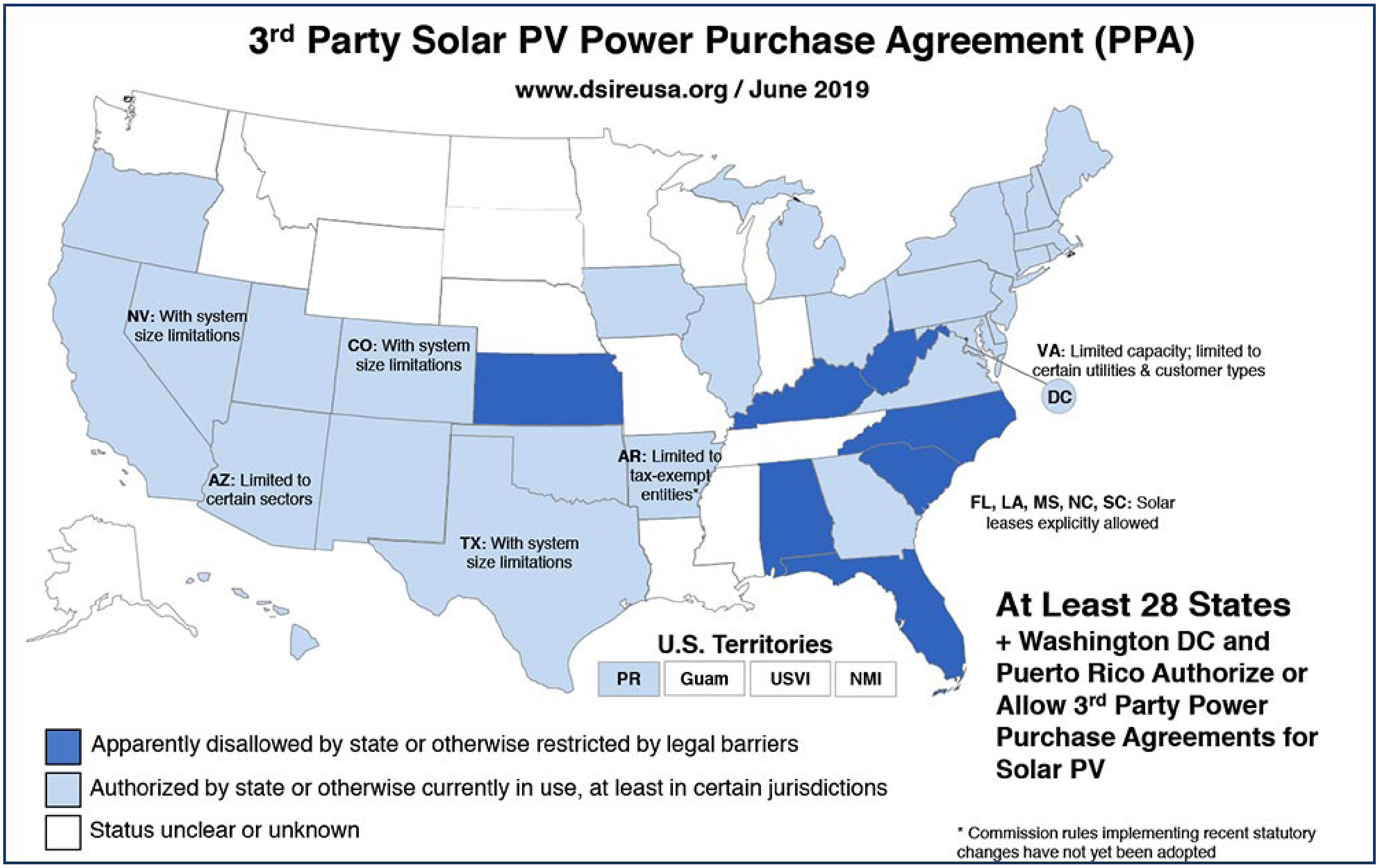
"Offering service 'to or for the public' means generating power 'intended for and open to the use of all the members of the public who may require it," the company said. "The 'public' means the public at large, not a limited subset of the public that stands in a special contractual relationship with the facility owner. By passing statutes that regulate public utilities, the Wisconsin Legislature never intended to regulate sales of electricity that serve a 'limited' or 'restricted' class of customers."

Shear also cites a 1924 ruling in which a group of neighbors formed a co-op to construct a power line; a 1932 case over a dam Ford Motor Co. built to power an assembly plant; and another landlord case in 1967 — none of which was deemed a public utility.

Eagle Point also points out that no excess electricity would flow back onto the grid, nor would the solar arrays use WE's distribution lines or other equipment to transport power.

Shear said the 1911 case has been upheld many times. "I think we have some pretty strong case law behind us," he said. "The legal

MISO News



Wisconsin is one of 15 states that have not clarified whether they allow third-party solar power purchase agreements. | *North Carolina Clean Energy Technology Center's Database of Incentives for Renewables & Efficiency (DSIRE)*

work has already essentially been done: If you have a single customer, you're not a public utility."

Shear said he considers his Wisconsin suit stronger than his Iowa case because his home state didn't have any decided cases on what constitutes a public utility.

Eagle Point also says its situation "parallels" that of a medical center that the Wisconsin PSC recently ruled could generate its own power through a subsidiary thermal company.

A representative of the Wisconsin PSC has said the commission cannot comment on pending litigation.

Unlike a regulated utility, one solar agreement with the city of Milwaukee won't make Eagle Point a "natural monopoly," the lawsuit argues.

Shear is also confident that Milwaukee will be perceived by the courts as a customer, not the public, despite it being a municipality.

"The city of Milwaukee is a single customer. … I'm not selling to the public. There's a pretty clear distinction there. I'm just making this technology available to everyone in a commercially reasonable way."

When the deal was scuttled, Shear said he was six months' deep into engineering work and meetings with the city and WE engineers.

"I purchased well over $1 million [of] equipment," he said. "I had committed my capacity to this. I wasn't working on other projects."

In total, Shear estimates he lost about a half-million dollars on the project. He also said Eagle Point missed out on a 2018 grant that would have been awarded had the project been completed by December as originally scheduled.

Shear said he's fighting WE's position to help cities access increasingly inexpensive renewable energy and meet carbon-reduction goals.

"I want to resolve this because this has chilled dozens of municipal solar deals across Wisconsin," Shear said.

Changing Energy Landscape

Shear says utilities are going to have to accept those in their service territories gaining the ability to generate their own electricity.

"This is a big deal. We Energies has to adapt and grow their business model to expect that their customers are going to be able to produce their own energy. That's the way it is from here on out," Shear said.

"They don't own the sun," he added after a beat.

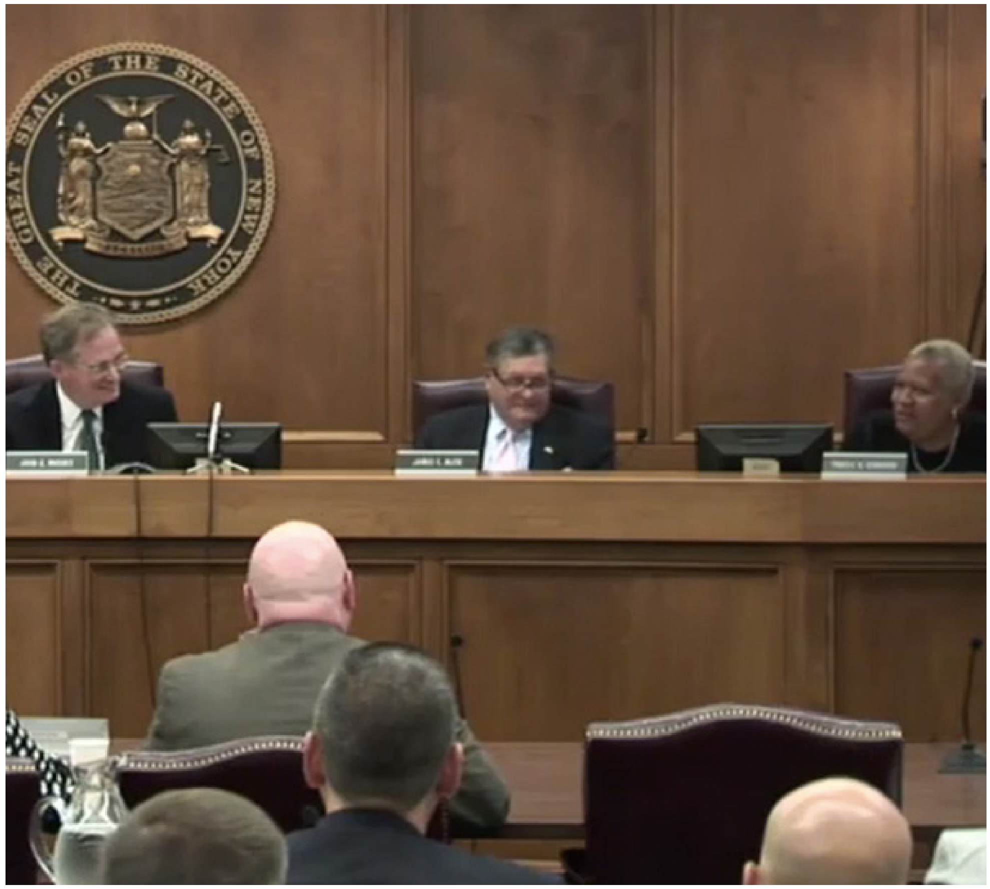
Shear expects the battle will eventually reach the Wisconsin Supreme Court.

"My operating presumption is and always has been that it's going to end up at the state Supreme Court. … While I don't speak for We Energies, I can't see them giving up. I'm not giving up either." ■

NYISO News

NYPSC OKs Westchester Plan, Expands EV Charging

By Michael Kuser



The PSC held its regular monthly session in Albany on July 11.

New York regulators Thursday approved a consumer awareness and incentive campaign for clean energy development in Westchester County, developed jointly by the county and the New York State Energy Research and Development Authority (Case *19-M-0265*).

John B. Rhodes, NYPSC

"Transitioning to a carbon-neutral economy requires all hands on deck, and New Yorkers are eager to do their part," New York Public Service Commission Chair John B. Rhodes said. "NYSERDA's Westchester County awareness program, developed in response to Con Edison's natural gas moratorium for new customers, represents a smart and strategic approach to assist Westchester's communities, businesses and residents in accessing reliable clean energy alternatives to natural gas and to become more energy efficient."

The action plan includes $165 million from Con Ed to support installation of heat pumps and energy efficiency and $32 million in financing provided by the New York Power Authority for its Westchester customers to retrofit heating systems with clean energy alternatives.

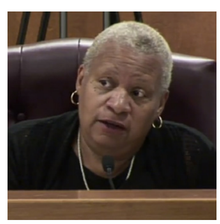
NYSERDA will also kick in $28 million to help new customers, including low-income residents, access alternative heating and cooling systems and energy efficiency services, and $25 million for energy efficiency measures for existing customers.

Diane Burman, NYPSC

"If we're being honest, what drove the action plan was the moratorium, so we need to look at what were the root causes of that moratorium ... and has the action plan alleviated any of those," said Commissioner Diane Burman, who voted against the measure.

Commissioner Tracey Edwards, attending her first session, voted for the program but said, "What I would ask is that we do a little bit more on the consumer side, the residential consumer side, because when I received the information on the workshops that had already taken place, it [was] really geared toward the business community."

Amended Electric Emergency Plans



Tracey Edwards, NYPSC

The PSC also approved amended electric emergency response plans (ERPs) for the state's major utilities (*Case 18-E-0717*).

The ERPs outline processes and procedures needed to respond to a wide array of emergencies, and this year the commission expanded staff review to include recommendations from their investigation following five large storms that occurred between March 2 and May 20, 2018.

The most substantial recommendations revolved around road clearing, damage assessment, estimated times of restoration, and utility communication with customers and municipalities, the commission said, with most improvements related to the inadequate performance of New York State Electric and Gas, Con Ed and its subsidiary, Orange & Rockland.

"All three utilities did not adequately address road closures and failed to properly coordinate and communicate with counties and localities," the commission said.

Gas Pipes: Cautionary Tale

National Grid may face a financial penalty for failing to properly train and supervise natural gas pipe installers at its two downstate gas utilities — Brooklyn Union Gas Co. (KEDNY), serving Brooklyn, and KeySpan Gas East Corp. (KEDLI), serving Long Island.

After an investigation spurred by an anonymous tip, the PSC ordered the company to explain why it should not commence a penalty action after the utilities failed to comply with the commission's safety rules related to gas infrastructure work in their service territories (Case *17-G-0317*).

The commission also alleged the companies

NYISO News

failed to inspect work completed by its contractors during construction at sufficient intervals to ensure compliance and that it allowed work to be completed by plastic fusers and plastic fusion inspectors not properly qualified to do the work.

"We will hold utilities strictly accountable when they do not comply with our gas safety rules, designed specifically to protect life and property," Rhodes said. "In this instance, staff's investigation presented credible information warranting the commission to require National Grid to respond formally to the investigation's findings."

The commission ordered National Grid to respond within 45 days and is also considering a prudence proceeding to ensure that ratepayers don't bear the costs incurred to correct hundreds of construction deficiencies.

The order starts an enforcement proceeding and is not a final determination by the commission concerning the allegations.

On top of the Department of Public Service's 2015 findings that National Grid had committed safety violations during construction of the Northern Queens Pipeline Project, in late 2016 an anonymous tipster alleged that work by Network Infrastructure, a contractor working on behalf of National Grid, did not comply with state safety regulations.

The anonymous letter also alleged that Network employees had been given the answers to online operator qualification tests. The letter alleged that, in one instance, high schoolers took the tests and snapped cell phone pictures of test questions from which answer sheets were created.

DPS staff confirmed the cheating allegations and required National Grid to re-dig much of its completed work from 2015 and 2016, which resulted in finding at least 1,500 regulatory violations, the commission said.

KEDNY has approximately 1.2 million customers and KEDLI has 590,000 customers.

EV Chargers Across the State

The PSC approved expanding its DC fast-charging infrastructure program for electric vehicles by making fast-charging plugs at newly constructed charging stations eligible for an incentive (Case *18-E-0138*).

The incentive applies if the station includes a standardized plug type of equal or greater charging capability as the other proprietary plugs being installed at the station.

"Electric vehicle deployment will play a key role in meeting the dramatic carbon-reduction goals set forth in the Climate Leadership and Community Protection Act," Rhodes said. "We must electrify the transportation sector to achieve a carbon-neutral economy."

In February, the PSC approved a $31.6 million initiative to make nearly 1,075 new, publicly accessible fast-charging plugs eligible for annual incentives. Those stations can charge a long-range EV in 20 minutes, compared to 20 hours using a typical home charger, or four to eight hours using a level 2 charger.

As of July 1, New York reported more than 4,000 EV charging stations installed statewide.

The commission denied Tesla's request that its proprietary charging technology alone be eligible for the incentives, but it said the company may earn the incentives if a standardized plug is co-located at the same site. Another company, ChargePoint, operates the most EV charging stations in the state, according to the DPS. ■

States, Regulators: Look Outside PJM for Next CEO

By Christen Smith

PJM's state advocates and regulators want the organization to focus on external candidates as it continues the search for a new CEO — someone capable of prioritizing policy goals above "comity" with neighboring RTOs and ISOs.

Leaders from the Organization of PJM States Inc., the New Jersey Board of Public Utilities, the Consumer Advocates of the PJM States, and attorneys general from Delaware, Maryland and D.C. sent *letters* last week to the head of the RTO's search committee, Board of Managers member Neil Smith, detailing what qualities former CEO Andy Ott's replacement should possess. (See *PJM CEO Andy Ott to Retire*.)

Ott announced his retirement effective June 30 after two decades with the RTO, during which time he helped launch the wholesale energy market and navigated the fallout of the GreenHat Energy default, the latter of which he described as one of his greatest challenges.

Interim CEO Susan J. Riley said last week she expects to be around "about four months" while the search committee picks a new leader — and everyone, whether inside PJM or not, is on the table.

Some stakeholders hope it's the latter of those two categories, however.

Aside from an economic and policy background and commitment to ushering in a cleaner power grid, CAPS President Kristin Munsch *said* the new CEO should want to work with states' environmental goals — not against — and build a stronger partnership with the Independent Market Monitor.

"Just as PJM recognizes the rights of states to their policies, PJM must recognize the right of the IMM to be an independent body," she said. "Arguments parsing Tariff language distract from the larger questions of how to use competitive markets to provide affordable and reliable electricity service."

Acknowledging the necessity for PJM "to constructively work" across its seams on the "shared mission of reliability, New Jersey BPU President Joseph Fiordaliso also contended that "PJM management too often elevates a desire for comity with its sister ISOs and RTOs over representing the public interests of its own constituent states.

Former PJM CEO Andy Ott | © *RTO Insider*

"This issue is particularly important to states like New Jersey, which sit directly on the seam between PJM and the New York Independent System Operator, and which have been responsible for fully one-third of all PJM transmission costs allocated over the past 15 years," Fiordaliso *said*.

He said stymying climate change must be top of mind for PJM's new leader as the RTO stands at the precipice of "tectonic shifts in their mission."

Fiordaliso said an outside candidate could serve as a "fair and neutral arbitrator" among stakeholders, noting that leaders from other RTOs and ISOs should be avoided because "the management of those organizations have struggled to balance the oft conflicting views of state and federal regulators."

"In a more tangible sense, we recommend that the search committee work to identify candidates capable of driving two (sometimes conflicting) policy agendas at the same time," he said. "This experience will ensure PJM's best-in-class management of today's electric grid and vigorous planning for the needs of tomorrow's electric grid."

The attorneys general *agree* that supporting grid innovation that complements aggressive climate change policies adopted in some PJM states will be a key focus for the new CEO.

"PJM's president should also have the economic and policy background to understand that state clean energy preferences are not out-of-market distortions to PJM interstate markets, but instead are important market corrections," the officials said in their joint letters. "These policies address pressing environmental externalities and will modernize our state economies, creating jobs as well as environmental benefits."

Smith instructed PJM members to submit all recommended candidates to the committee no later than July 19. ■

PJM Operating Committee Briefs

Grid Handled Emergency Procedures Well

PJM staff called June an uneventful month for grid *operations*, despite 23 emergency procedures — including 21 post-contingency local load relief warnings (PCLLRWs) and three hot weather alerts.

PCLLRWs are utilized in the coordination of post-contingency load shed plans between PJM and transmission owners. June's events occurred in the RTO's western transmission zones, including Commonwealth Edison, Eastern Kentucky Power Cooperative, American Electric Power, American Transmission Systems Inc., Pennsylvania Electric, and Duke Energy Ohio and Kentucky. There was one PCLLWR on June 25 in the Atlantic City Electric transmission zone for the Chestnae-Moss Mills line.

The hot weather alerts occurred June 27-29 RTO-wide.

Black Start Packages Coming Together

PJM's Janell Fabiano told the Operating Committee on July 9 that stakeholders will soon present new rules for black start resource fuel requirements.

Stakeholders began meeting in July 2018 to *reconsider* whether the existing fuel requirement of 16 hours proved sufficient given PJM's focus on resilience in recent years. The group is also considering ways to mitigate high-impact, low-frequency events across all black start resources and fuel types.

Calpine, PJM and Monitoring Analytics continue to work on three similar plans to define fuel assurance and tweak the hourly reserve requirement. Fabiano said stakeholders will bring the three finalized packages to both the OC and the Market Implementation Committee for votes in the fall. Changes will not move forward without support from both committees, she said.

Non-retail BTM Generation Business Rules

Stakeholders delayed voting on *changes* to Manuals 13 and 14D that refine responsibilities, processes and procedures related to how PJM manages non-retail behind-the-meter generation (NRBTMG). (See "BTM Generation Rules Preview," *PJM OC Briefs: June 11, 2019*.)

The revisions to Manual 13 expand upon what events trigger the use of NRBTMG to include "maximum generation emergency" and "deploy all resources" actions, which address capacity shortages or transmission security emergencies.

In Manual 14D, staff updated Appendix A to clarify generator operational requirements for the reporting, netting and operational requirements of NRBTMG.

The delay allows some stakeholders more time to review the revisions. PJM will seek endorsement at the August OC.

Generation Outages

PJM advanced changes to Manual 10: Pre-scheduling Operations absent the stability-related modifications called into question at the May 14 OC meeting. (See "Generation Outage Revisions Delayed," *PJM OC Briefs: May 14, 2019*.)

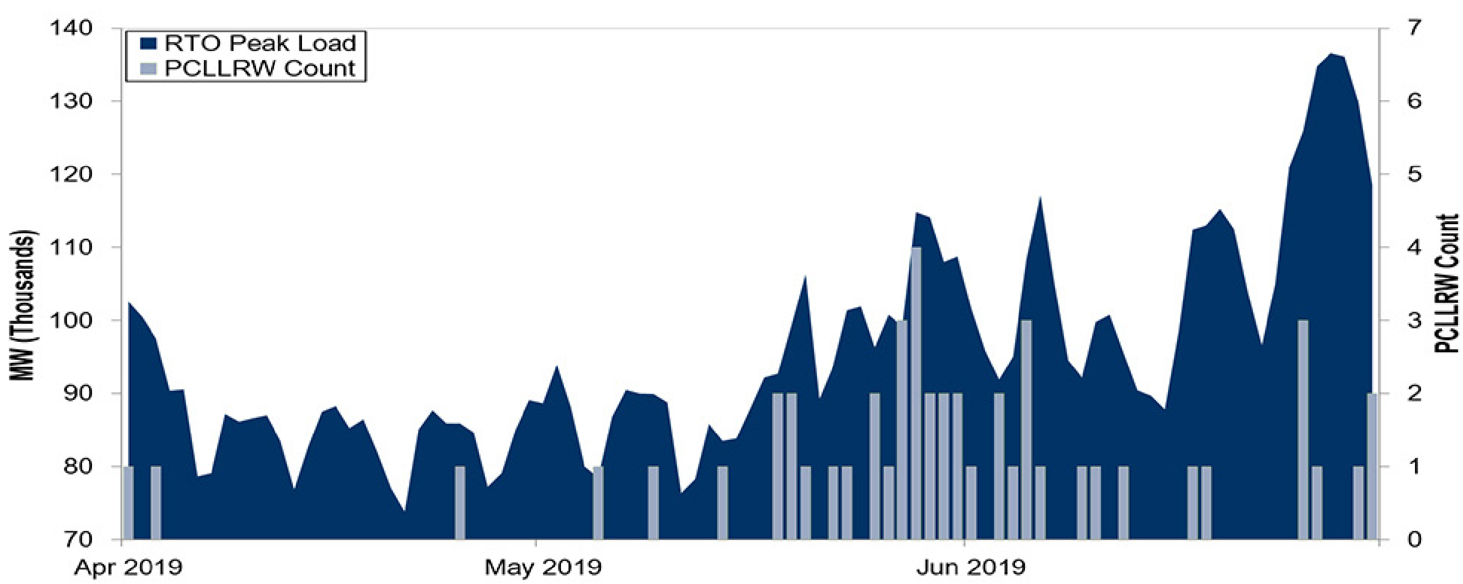
Stakeholders instead endorsed the *remainder* of the changes developed out of the periodic cover-to-cover review of the manual that clarifies outage ticket rules for deactivation and black start resources.

Manual Changes Endorsed

Stakeholders unanimously endorsed changes to the following manuals:

- Manual 39: Nuclear Plant Interface Coordination (See "Nuclear Plant Interface Coordination Updates," *PJM OC Briefs: June 11, 2019*.)
- Manual 13: Emergency Operations Updates (See "Emergency Operations Updates," *PJM OC Briefs: June 11, 2019*.) ■

— Christen Smith



Post-contingency local load relief warnings (PCLLRW) count versus peak load over the last three months. | *PJM*

Shell Demands Seat at GreenHat Settlement Table

By Christen Smith

Shell Energy wants a seat at the GreenHat Energy settlement table, saying it is "uniquely situated" in the proceeding and could bear a disproportionate financial burden based on its outcome.

In its *request for rehearing* filed July 5, Shell argued FERC erred when it dismissed more than a score of late-filed motions from intervenors seeking to participate in the unwinding of GreenHat's financial transmission rights portfolio. The company was declared in default in June 2018 after it failed to make good on its mounting losses.

"Departing from longstanding FERC policy against settlements that may have an impact on others not present during the negotiations, the commission has initiated a course of action that will allow a handful of parties to decide" the best way to liquidate GreenHat's portfolio, Shell said (ER18-2068). PJM has said having to liquidate the portfolio under existing rules could cost members $430 million or more.

On June 5, the commission gave RTO members 90 days to settle disputes about how to move forward before kicking off a paper hearing on PJM's request to clarify FERC's ruling rejecting the waiver. (See *FERC: PJM Settle Disputes Before GreenHat Hearing*.)

On July 8, Chief Administrative Law Judge Carmen A. Cintron canceled a settlement conference scheduled for July 10 "to allow more time to prepare for future conferences." Cintron said the cancellation would not affect a conference set for July 26.

Shell was among more than 20 petitioners that filed after the comment period for PJM's waiver passed. FERC rejected the late filings, saying none demonstrated "requisite good cause for late intervention."

But Shell says a PJM Tariff provision caused its tardiness, a circumstance that it says none of the other petitioners face.

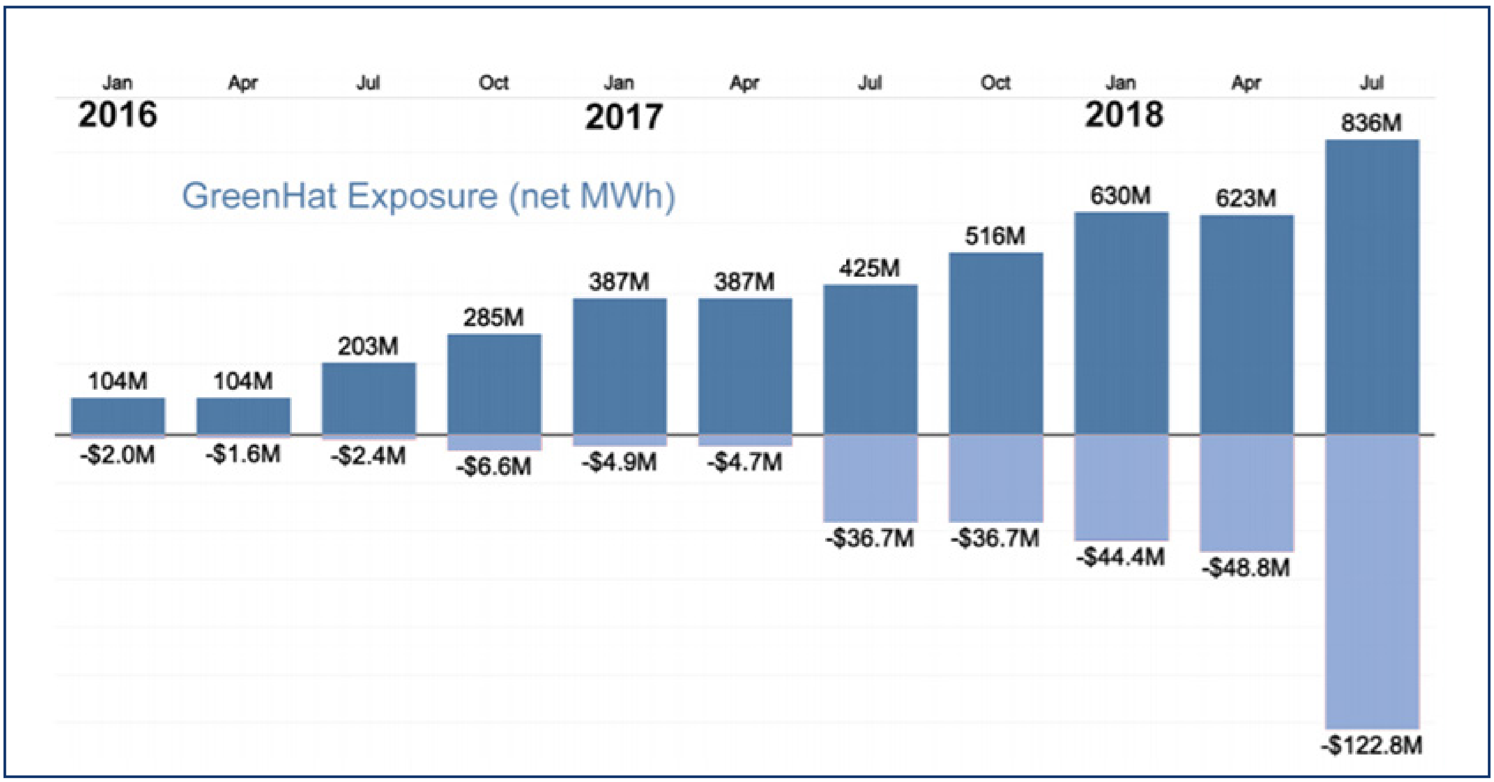
"Shell Energy entered into three bilateral transactions involving transfers of a portion of GreenHat's now defaulted FTR portfolio to Shell Energy and back to GreenHat," the company wrote. "As a result, PJM informed Shell Energy that it would seek guarantee and indemnification from Shell Energy for the portion of GreenHat's FTR portfolio that was so transferred. Liquidation of GreenHat's FTR portfolio could substantially affect the amount sought by PJM under the guarantee and indemnification claim." (See *Shell Energy Seeks to Avoid Liability in GreenHat Trades*.)

Shell says PJM didn't tell the company it would be subject to this clause until after the comment period passed and that no other party participating in the settlement discussions could "adequately represent its interests."

"Because any settlement to resolve issues related to the massive GreenHat default will necessarily impact all PJM members subject to default allocation assessment (and, in turn, ratepayers), excluding Shell Energy and others from settlement negotiations among only a few parties is unlikely to result in a settlement that is in the public interest," the company said.

Shell further argued that its participation would not "unfairly prejudice or burden" the allowed parties, none of whom opposed its intervention.

"As Shell Energy originally explained, it is not presenting new evidence or law, nor altering any previously established procedural schedule," the company wrote. "Shell Energy accepts the record as it stands." ■



GreenHat's significant growth in exposure and MTA loss | *PJM*

PJM Stakeholders Push Unified Cost Calculator

By Christen Smith

VALLEY FORGE, Pa. — PJM generators urged fellow stakeholders to support a unified opportunity cost calculator capable of wiping out the compliance risks of the dual systems currently offered through the RTO and its Independent Market Monitor.

Bob O'Connell, Panda Power Funds | © *RTO Insider*

"PJM wants the status quo with respect to its calculator and the Monitor wants its calculator, and we are still in this situation where market participants can't get one calculator to eliminate compliance risk," Bob O'Connell, director of regulatory affairs and compliance for Panda Power Funds, said during a Market Implementation Committee meeting on Wednesday.

Under current procedure, market participants can either use PJM's calculator in Markets Gateway or the Monitor's modeling system to build energy cost offers with appropriate adders that help ensure a generator will recoup losses when its resources are scheduled outside of their most economic operating intervals. Some of these opportunity costs arise when regulatory agencies impose environmental run hour restrictions, physical equipment limitations trigger operational restrictions, and *force majeure* events constrain access to fuel.

"The objective is to make the generator whole," said Glen Boyle, manager in PJM's operations analysis and compliance. "Neither PJM nor the IMM will be presenting packages, because we are OK with the status quo."

Glen Boyle, PJM | © *RTO Insider*

Clearly, stakeholders are not.

A New Path

O'Connell presented the MIC with three proposals — drafted in consultation with Dominion Energy — that streamline the calculators to varying degrees.

The first makes small changes that don't force PJM to rewrite its calculator, O'Connell said. The second revises PJM's modeling process to mimic the Monitor's, which many stakeholders prefer for its reliability. The third consolidates the former package into one single calculator, "eliminating all compliance risk," O'Connell said.

"When you use the Market Monitor's calculator, the market participant's only risk is taking the adder the Monitor provides and incorporating into its offer properly," O'Connell said. "While there is some compliance risk, it's very limited. As long as you know how to cut and paste, you're usually in pretty good shape."

The PJM calculator, however, gives the market seller more control over the modeling process, allowing more room for error and raising compliance risks — the source of O'Connell's concern when he proposed a task force to revise the calculators in March 2017, he said.

"I'm concerned we won't be able to get there [one consolidated calculator]," O'Connell said. "We basically decided to offer three packages so we could at least get to something that improves the situation a little more."

Panda and Dominion will seek endorsement of one of the proposals at the August MIC meeting, O'Connell said.

The packages come five months after O'Connell made a motion at the February Members Committee meeting to table a vote on Operating Agreement language that would force PJM to accept the IMM's calculator. (See "Calculator Vote Place in a 'Parking Lot,'" *PJM MRC/MC Briefs: Feb. 21, 2019*.)

At the time, O'Connell said the unusual motion puts the issue in a "procedural parking lot," giving members flexibility to bring up the issue on short notice in case PJM suddenly decides the Monitor's calculator is no longer valid.

O'Connell drafted the language after PJM told members last August it would reject the Monitor's opportunity cost calculator, the culmination of a yearlong dispute over the "increasingly" divergent results produced by the two organizations. (See *Stakeholder Proposal Aimed at Ending PJM-IMM Dispute*.) The PJM Board of Managers approved Manual 15 revisions in January that governed the use of the IMM calculator as an alternative, effectively reversing the RTO's earlier decision.

Boyle said Wednesday that PJM must maintain a calculator as mandated by the Tariff and will make clarifying *updates* to Manual 15 regarding immature units, dual-fuel units and application functionality. ■

PJM Market Implementation Committee Briefs

Interim CEO Steps into Role

PJM Interim CEO Susan J. Riley | *© RTO Insider*

VALLEY FORGE, Pa — Interim PJM CEO Susan J. Riley opened last week's Market Implementation Committee meeting with an optimistic message about moving the organization forward after Andy Ott's departure June 30.

"There's a lot of work to do, particularly with our markets coming out of the whole FTR/GreenHat issue," she said, referring to financial transmission rights trader GreenHat Energy's default in June last year. "I'm here to assist with that and provide perspective to PJM. We've got to make these markets safe for participants." (See *Naive PJM Underestimated GreenHat Risks*.)

Ott announced his retirement as CEO in May, marking the second top executive departure this year. (See *PJM CEO Andy Ott to Retire* and *PJM CFO Retiring in Wake of GreenHat Default*.)

Riley, a member of the Board of Managers, said she expects to serve as CEO for the next four months. She told the MIC that the organization is close to announcing the woman selected to be the RTO's first chief risk officer, per the recommendation of the independent probe into how the GreenHat default unfolded.

"We are very excited to having her come on board," she said. "There will be a lot more to come with ensuring the safety of our markets."

5-Minute Dispatch and Pricing

Stakeholders unanimously endorsed a *problem statement* that criticizes the real-time security-constrained economic dispatch (RT SCED) and market pricing processes that PJM uses to send dispatch signals to generators and calculate LMPs.

Siva Josyula of Monitoring Analytics last month said a price publishing delay on April 8 — as well as a July 10, 2018, low area control error (ACE) *event* and corresponding Manual 11 revisions — call into question the transparency of PJM's RT SCED processes.

The MIC will spend the next several months reviewing the issue and recommending necessary changes.

Order 841 Manual Revisions Endorsed

The MIC approved a slew of manual revisions related to FERC Order 841 on electric storage participation. The changes include updating *Manual 11: Energy & Ancillary Services Market Operations*; *Manual 18: PJM Capacity Market*; and *Manual 15: Cost Development Guidelines* to align PJM policies with those outlined by the commission.

Laura Walter, PJM | *© RTO Insider*

Laura Walter, senior lead economist for PJM's advanced analytics and surveillance department, said Manuals 11 and 18 will clarify that storage resources can participate in the RTO's markets and can dispatch and set price as seller and buyer. The revisions also note that stored megawatt-hours are billed at LMPs as wholesale.

In Manual 15, revisions detail business rules for cost offer development — specifically for hydroelectric resources and batteries and flywheels, PJM Senior Engineer Danielle Croop said. Staff also added definitions for efficiency factor, fuel cost, variable operations and maintenance (VOM) and ancillary service costs.

Efficiency factors measure the ratio of generation produced to the amount of electricity used to charge, Croop said. Fuel cost will use the average charging cost and will be defined in fuel-cost policies. Maintenance and operating cost inclusion and exclusion guidelines will be submitted in resources' VOM templates, she said.

Modeling Units with Stability Limitations

The MIC is gearing up to discuss whether PJM should require generators to submit outage tickets during forced curtailments stemming from nearby transmission maintenance.

Bob O'Connell, director of regulatory affairs and compliance for Panda Power Funds, presented a first read of the *problem statement* and *issue charge* he promised to bring during an Operating Committee meeting in May. His concerns arose out of proposed revisions to Manual 10 that would require generators to use outage tickets for stability-related limitations — possibly encouraging price distortion. (See "Generation Outage Revisions Delayed," *PJM OC Briefs: May 14, 2019*.)

O'Connell argues PJM's decision to remove supply from the market to address stability constraints will result in some units committing at price-based offers, rather than cost. Under the RTO's rules, only the affected generator would know of the constraint, O'Connell said, therefore gaining a competitive advantage over other units and possibly incorporating greater mark-ups into their offers.

As a solution, O'Connell suggested PJM implement a closed-loop interface around the affected resource that restricts the output to below the stated stability limit — and it must be used in each of the markets. He also encouraged the RTO to publicize stability limits on OASIS prior to contacting the affected generator.

The MIC will be asked to endorse the problem statement at the August meeting and work on possible solutions during the committee's meetings over the next few months.

Deadline Approaching for Gas Contingency Comments

PJM's deadline for comments on its new Tariff *language* for gas pipeline contingencies comes and goes July 17 — but it appears many stakeholders remain unhappy with the latest draft.

On Feb. 19, FERC rejected the member-approved mechanism that would have implemented a process for market sellers seeking cost recovery for certain gas contingencies associated with the RTO's instruction to temporarily switch to an alternative fuel or fuel source because of pipeline breaks or the loss of compressor stations (ER19-664.) The proposal included nine categories of switching costs, such as park-and-loan service charges and overrun charges. (See *FERC Rejects PJM's Gas Pipeline Contingency Proposal*.)

Thomas DeVita, PJM's senior counsel, said FERC staff dropped some hints about how to tweak the filing for better success the second time around. (See *PJM Revisits Gas Pipeline Contingency Plan*.) He said staff discouraged the RTO from submitting an itemized list of switching costs, as it did in the first filing, and instead focused on procedures surrounding "explicit authorization" to switch between pipelines and any new limitations on the amount of gas burned after the switch occurs.

Marji Philips, Direct Energy's director of RTO

Continued on page 36

PJM News

PJM Stakeholders Still Divided on Fuel-cost Policies

By Christen Smith

VALLEY FORGE, Pa. — Consensus on fuel-cost policies (FCPs) may elude PJM stakeholders as the Market Implementation Committee prepares for a vote on three divergent plans to restructure penalties and annual reviews.

The Independent Market Monitor and a collection of stakeholders want the RTO to ditch its yearly evaluation of unchanged FCPs and to consider extenuating circumstances when calculating fines for sellers who break those policies by failing "aggregate" market power tests.

Joel Romero Luna, Monitoring Analytics | © RTO Insider

"We are trying to go back to the way we did things before," said Joel Romero Luna of Monitoring Analytics. "PJM or the IMM approved a fuel-cost policy and that remained in place until one of those parties or the participant said it was not good enough anymore."

PJM *argued* that eliminating the annual review could allow ineffective policies to slip through the cracks, though it would consider a truncated analysis process as part of a compromise.

"We don't want them [FCPs] to become stale," said Glen Boyle, PJM's manager of system operations analysis and compliance. "We want them reviewed once a year."

When it comes to implementing an aggregate market power test, however, RTO staff said adopting such a process was "out of scope" of the MIC special session for retooling FCP rules.

PJM's existing rules went into effect more than two years ago after months of contentious debate. In June 2017, the Monitor announced that it had rejected fewer than 5% of 479 FCPs during its annual review, accounting for roughly 11% of generating units. (See *PJM Monitor Rejects Fuel-Cost Policies for 11% of Units*.) Sellers without approved FCPs who offer into PJM's markets currently face a penalty for doing so — though the Monitor proposes no longer allowing generators without an approved FCP to submit nonzero cost-based offers.

The Monitor wants to keep the current penalty factor when a unit fails the local/aggregate three-pivotal-supplier (TPS) test or submits an offer above $1,000/MWh. Romero Luna said the penalty should double when the unit either clears the day-ahead market or runs in real time on an incorrect cost-based offer and sets the marginal LMP, receives make-whole payments or offers above $1,000/MWh. Penalties would decrease to 10% when those two conditions don't apply.

If a generator "self-identifies" the error and neither of the impact conditions apply, the penalty would drop 50%. If one or both of the situations occur, the penalty is reduced just 25%.

"We heard the current penalty didn't have an incentive for people to self-identify errors that they made and that the penalties were too high," Romero Luna said.

Under the Monitor's *plan*, a self-identifying generator with a 500-MW output and average real-time LMP of $40/MWh would see its existing $24,000 penalty reduced to as little as $1,200.

Adrien Ford, ODEC | © RTO Insider

Adrien Ford of Old Dominion Electric Cooperative said a joint *proposal* from stakeholders shares a lot of similarities with the Monitor's plan — except that self-identified errors reduce penalties to 25% and it creates a "safe harbor" policy for "unusual situations not contemplated by the FCP."

"We followed the IMM framework while adjusting the value and adding a cap," she said. More specifically, the joint stakeholder plan applies the current penalty factor if a unit clears the day-ahead market or runs in real time on cost-based offers and is paid a balancing operating reserve or the cost offer is above $1,000/MWh — or a unit fails the TPS test for constraints. If none of these conditions apply, the full penalty is reduced 90%.

The penalty calculation is assessed for each hour of the invalid offer and is capped at the calculated net energy margin for any impacted hour, Ford said.

The MIC will vote on the packages at its August meeting, just in time for the self-imposed Aug. 7 deadline set for the special session. ■

PJM Market Implementation Committee Briefs

Continued from page 35

Marji Philips, Direct Energy | © RTO Insider

and federal services, continues to believe the entire filing is fundamentally flawed and puts an unnecessary burden on load.

"If you want to have the right market response, you will look for other market incentives so that you're not switching the cost of generation to load, because that's what's happening here," she said. "The whole purpose of competitive markets is that the generator bears the risk, not load."

She further argued that generators should be prepared to compensate during emergencies lasting 24 hours or more.

"If the conditions last longer than 24 hours, it's no longer an emergency," she said. "PJM shouldn't be shifting the burden to load because the generator didn't incorporate the risk into its CP offers. The generator guaranteed performance under CP, so it's not load's responsibility to cover the extra costs of that fuel."

O'Connell agreed that mandatory operating instructions should only last for a set period of time, but he worried that memorializing such rules could encourage unsavory market behavior.

"One thing to address … the directive expires based on the rule, then 10 minutes later PJM issues the same directive," he said. "Have we constructed a rule that can be worked around? Market participant perspective is that the market participant should be responsible for deciding what risks they care to take and what costs they care to incur, and if PJM overrides it, PJM should pick up the tab."

It's a sentiment Philips said she agrees with completely. ■

— Christen Smith

PJM News

PJM PC/TEAC Briefs

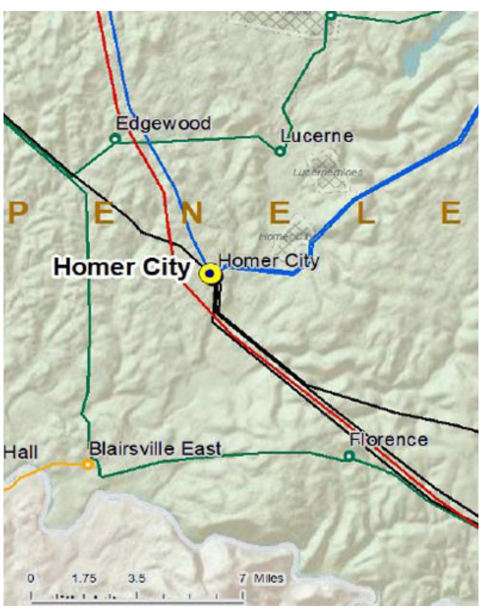
Offshore Wind Update

VALLEY FORGE, Pa — PJM's Merchant Transmission and Offshore Wind Task Force will soon bring potential rule changes for offshore wind development to the Planning Committee for consideration, RTO staff said Thursday.

John Reynolds, of PJM's resource adequacy department, said stakeholders have so far offered three packages that address how transmission developers for single non-controllable AC lead lines could obtain capacity interconnection rights (CIRs) without committed generation.

The task force formed in February after the PC approved a problem statement and issue charge that would pave the way for existing and future offshore wind projects to develop throughout PJM, where researchers believe the potential is "big." (See "PC Moves Forward on Offshore Interconnection Rights," *PJMPC/TEAC Briefs: Feb. 7, 2019* and *Big Prospects for Offshore Wind in PJM*.)

Under existing rules, merchant transmission developers are only eligible to obtain transmission injection and withdrawal rights for DC facilities or controllable AC facilities connected to a control area outside the RTO. And because PJM does not offer CIRs to non-controllable AC lines, it is unable to perform stability or short-circuit analyses, as is typically done when a committed generation source exists.



FirstEnergy has identified a special protection scheme for the 51-year-old Homer City North 345/230/23-kV transformer in Pennsylvania. | *FirstEnergy*

Two of three *packages* introduce the concept of transferrable CIRs (xCIRs). In one plan, PJM would base the xCIRs on thermal studies only, while the second would allow requests for xCIRs based on all standard studies using a generic generator model. Both plans would make the rights transferrable to a generator project in the queue one year after the execution of the interconnection study agreement (ISA).

A third plan would modify the generator request to allow delayed submission of its data and use generic modeling instead for the feasibility and impact study. The official data would be due no later than 90 days into the study.

"These three are not the only ones we expect to have," Reynolds said.

The task force has three more meetings scheduled before it returns to the PC for a first read of any draft language in September.

1st Read of Cost Containment Rules Coming in August

Mark Sims, PJM | *© RTO Insider*

Mark Sims, PJM's manager of infrastructure coordination, told the PC that staff will present Manual M14F draft language for a first read in August, concluding months of educational updates and coordination with the Independent Market Monitor.

The language will detail PJM's expanded cost containment process, which will include an updated hybrid fee structure. Sims previously told the PC that PJM's old tiered approach, approved in 2014, doesn't account for the increased cost of the new comparison framework that involves an independent consultant's review and legal and financial analyses. (See "New Fee Structure for Cost Containment Needed," *PJM PC/TEAC Briefs: May 16, 2019* and "PJM Developing Hybrid Fee Structure," *PJM PC/TEAC Briefs: June 13, 2019*.)

Staff will seek endorsement of the language at the September PC and Markets and Reliability Committee meetings.

Unchanged Load Model Selection Endorsed

Stakeholders unanimously endorsed PJM's load model *selection* for the 2019 reserve requirement study (RSS) after staff said it remained unchanged from the year before.

Patricio Rocha Garrido, of PJM's resource adequacy department, said the load model of 2003-2012 remains the best choice for studying the 2023/24 delivery year. Analysis shows minor deviation in megawatt distance between 2018 and 2019, but Rocha Garrido described this as "insignificant enough" to not alter the model.

PJM also recommends switching its peak week to a different period in July so that it occurs in the same month as the "world" peak, but not on the same dates — which historical data suggests is unrealistic. The "world" load models include dates from the neighboring MISO, NYISO, TVA and VACAR regions.

Dominion, FirstEnergy Supplementals

FirstEnergy has identified protection schemes using a certain vintage of relays and communication equipment that have a history of maloperation on its Shawville-Shingletown 230-kV and Elko-Shawville 230-kV lines in the APS/Penelec transmission zone.

The 51-year-old Homer City North 345/230/23-kV transformer in western Pennsylvania faces increased probability of failure because of obsolete parts, leaks, deteriorated control cabinet components, high levels of heating gasses and moisture, and type "U" bushings. Likewise, the 34.5-mile Armstrong-Homer City 345-kV line is deteriorating from woodpecker damage, top and bayonet rot, and weatherization.

Dominion Energy wants to add a new delivery point for Mecklenburg Electric Cooperative in Boydton, Va., to support a new data center campus with a total load in excess of 100 MW. The requested in-service date is April 1, 2020.

The company said its Chickahominy 500/230-kV, 840-MVA transformer has been identified for replacement as part of its ongoing transformer health assessment process. Dominion said it's the last known Westinghouse shell transformer — built in 1987 — on its system. These transformers are considered suspect because of previous transformer failures that reduced basic insulation level ratings and forced remanufacturing. ■

— Christen Smith

SPP News

SPP Seeks Slimmer Stakeholder Group Structure

By Tom Kleckner

SPP has launched an *initiative* to trim the number of stakeholder groups in its organizational structure, saying it will improve the RTO's effectiveness.

Staff are currently gathering feedback from members on various proposed combinations of merged working groups and committees and how best to ensure important work is not lost in the shuffle.

SPP is targeting 14 working groups and the Seams Steering (SSC) and Balancing Authority Operating (BAOC) committees. Exceptions include the committees that report to the Board of Directors and Members Committee, the Market Monitoring Unit, and the Credit Practices (CPWG) and Cost Allocation (CAWG) working groups. The CPWG reports to the Finance Committee, and the CAWG reports to the standalone Regional State Committee.

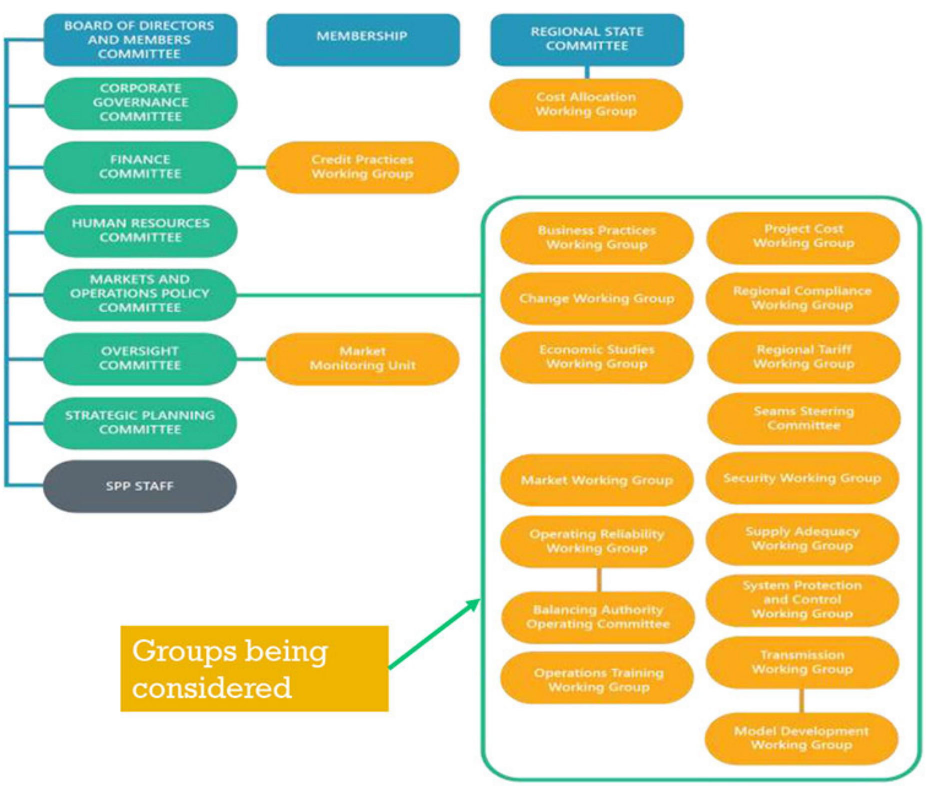
"With the organization's focus on value and affordability to our stakeholders, we're looking at a variety of potential measures to streamline processes, improve effectiveness and provide the highest degree of value possible," SPP Vice President of Engineering Lanny Nickell said in a statement.

Nickell said the effort originated in the Value and Affordability Task Force (VATF), which was formed in January to review the cost recovery of transmission investments as well as the ongoing benefit from those investments and SPP's operation. (See "Altenbaumer Continues to Exert his Influence," *SPP Strategic Planning Committee Briefs: Jan. 16, 2019*.)

He said the task force requested an assessment of SPP's organizational structure "that considers whether we can achieve more value by consolidating and improving coordination among groups and reducing meetings and travel across our sizeable footprint."

Staff have been gathering feedback on four proposed combinations:

- The BAOC, SSC, Operating Reliability (ORWG) and Operations Training (OTWG) working groups;
- The SSC and the Transmission, Economic Studies and Project Cost working groups;
- The Business Practices, Regional Compliance, Regional Tariff, Security and System Protection and Control working groups; and
- The Business Practices, Change, Market and Supply Adequacy working groups.



| SPP

Two of the combinations involving the SSC would see the committee disbanded, with its responsibilities picked up by either the Operating Reliability, Economic Studies or Transmission working groups. Staff have also suggested in one scenario the OTWG be disbanded, with an advisory panel or the ORWG picking up its training responsibilities.

"The discussions are in the early phases," SSC Staff Secretary Clint Savoy told his group during its Wednesday meeting. "In my personal opinion, I believe we should operate as if the Seams [Steering] Committee will continue."

Staff has also been gathering general suggestions from members on SPP's organizational group structure. Stakeholders have suggested reducing the number of face-to-face Markets and Operations Policy Committee (MOPC) meetings and using conference calls to address less contentious Tariff changes.

The MOPC meets quarterly two weeks before the board meetings and is responsible, through its organizational groups, for developing and recommending policies and procedures related to SPP's technical operations.

Stakeholders also suggested improving the working groups' effectiveness by having longer meetings with more work, coordinating meetings with similar groups, creating more "meaningful, action-oriented" agendas and facilitating information sharing through focus groups.

Nickell will update the MOPC on the effort during its July 16-17 meeting in Des Moines, Iowa. MOPC Chair Holly Carias, with NextEra Energy Resources, and Vice Chair Denise Buffington, with Evergy companies KCP&L and Westar, will also play a part in the presentation.

The VATF is to weigh in with its own feedback by July 31. The MOPC is scheduled to see draft recommendations during its October meeting, and the Corporate Governance Committee (CGC) will see them in November. The CGC will then recommend changes to the board in December or January, with the changes implemented in 2020. ■

SPP News

FERC OKs New SPP Interconnection Process

By Tom Kleckner

FERC has accepted SPP's proposal to refine its generator interconnection procedures by instituting a three-stage study process (*ER19-1579*).

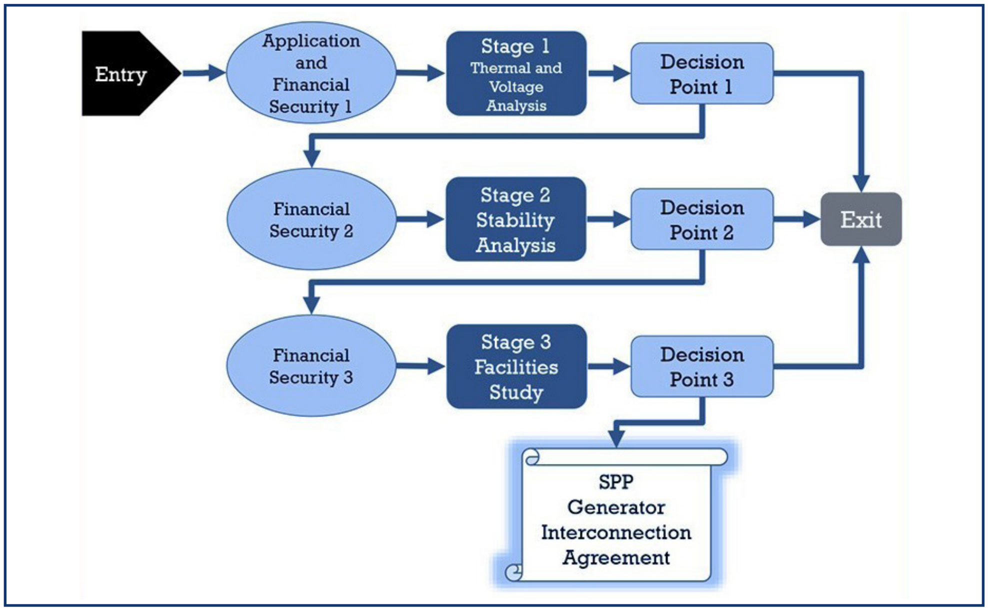
The RTO's Tariff revisions adopt a three-phase process of thermal and voltage analysis, stability analysis, and facilities study. They also change the eligibility for refunds of financial security.

The commission rejected concerns from Enel Green Power and EDF Renewables that SPP did not have the staff and resources to accomplish all the revisions' components.

"We are not persuaded to substitute our judgment for SPP's in determining the level of staff and resources that SPP needs to implement its proposal," the commission wrote in the June 28 order. It pointed out that the reforms might reduce redundancies and result in the "more efficient use of administrative time" that could be devoted to the new study process.

The changes include the elimination of the feasibility and preliminary queues, changes to the amount and timing of security deposits, publishing study models earlier in the process, and allowing penalty-free withdrawals when costs increase above certain thresholds. They became effective July 1.

The Tariff revisions were approved by SPP stakeholders in January following several years of development. The RTO filed its request in April. (See "Stakeholders Approve Streamlined Generator Interconnection Process," *SPP Markets & Operations Policy Committee Briefs: Jan. 15, 2019*.)



Proposed GI study process (3-stage) | *SPP*

In its filing, SPP said it had more than 440 interconnection or modification requests, totaling 81 GW of new generation capacity, in its interconnection study queue.

Enel and EDF argued it was unjust and unreasonable to "subject interconnection customers to higher and potentially nonrefundable financial security and a longer queue process" if SPP was unable to efficiently handle the process studies.

FERC disagreed, saying SPP's proposal to separate the security deposit into three payments, which are due before each of the three phases and become "further at-risk as the interconnection customer progresses through the queue … should help dissuade more speculative projects from entering later study phases, which should decrease the number of late-stage, disruptive withdrawals."

The commission also found the security deposit's financial outlays were not "excessive."

"Under SPP's design, the total financial security an interconnection customer will pay is roughly 20% of its estimated network upgrade cost responsibility, which is the total payment required for SPP's existing initial payment," FERC said. ■

SPP to Pay NERC Penalty from Staff Comp Funds

By Tom Kleckner

SPP this month reiterated its plans to recover the costs of a NERC penalty for reliability violations by dipping into its employee compensation pool (*ER19-97*).

In a heavily redacted filing shared with stakeholders at 4:47 p.m. on July 3 — just before the Independence Day holiday — the RTO said its Board of Directors determined the best way to recover the penalty's costs was to "offset the cost with funds that were approved and allocated to the SPP employee compensation pool," rather than charging members and market participants.

SPP paid the fine, which NERC approved in the RTO's role as a registered entity, last year out of a 2017 surplus "that was sufficient to pay the full amount of the monetary penalty."

The RTO said recovering the penalty cost from authorized employee compensation funds "essentially holds members, market participants and customers harmless from the cost of the reliability penalty."

The amount of the fine and the reason for the penalty have not been disclosed. SPP requested confidential treatment for the filing as privileged material and/or critical electric/energy infrastructure information "in order to mitigate potential risks to the reliability of the bulk power system under SPP's control." Seven of the 29 pages in SPP's filing were fully redacted and two pages were partially redacted.

SPP told *RTO Insider* that company policy keeps it from commenting on "such matters."

"Anything we could say publicly is already stated in the filing," spokesman Derek Wingfield said.

In FERC Order 672, the commission said that NERC violations "generally will be made public after the matter is filed … as a notice of penalty or resolved by an admission that the user, owner or operator of the bulk power system violated a reliability standard or a settlement or other negotiated disposition."

But SPP noted the order also allows a filer, if it believes information on the violation "could jeopardize the security of the bulk power system if publicly disclosed," to "fully support" its confidentiality claim in the nonpublic version of its proposal to recover penalty costs.

SPP added the language in its filing after FERC last year denied its request for waivers from regulations guiding the confidential treatment. The commission said SPP must allow intervenors to sign nondisclosure agreements to access information that the RTO believes should be withheld from the general public. FERC said its CEII regulations "recognize that intervenors in a commission proceeding … may need access to information that the applicant believes should be withheld from disclosure to the general public in order to participate effectively in the proceeding." (See *FERC Rejects SPP Confidentiality over NERC Fine*.)

SPP is a NERC registered entity in the Midwest Reliability Organization and Western Electricity Coordinating Council. It is required to comply with NERC reliability standards for its roles as a balancing authority, planning authority/planning coordinator, reliability coordinator, reserve sharing group and transmission service provider.

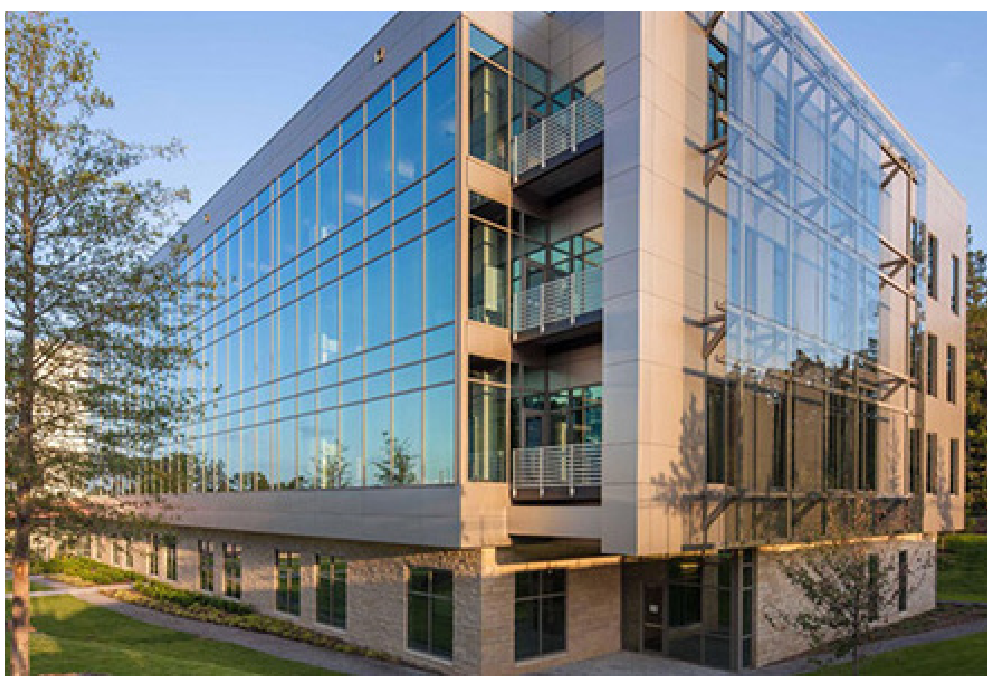
Under Attachment AP of SPP's Tariff, the RTO may seek recovery of reliability penalty costs by either directly assigning them to the responsible members or market participants or by allocating the costs to all members or market participants.

As justification for its decision to pay the penalty from its employee compensation fund, SPP cited FERC's 2008 "Guidance Order," in which the commission said RTOs could tie employee compensation to compliance with reliability standards as one possible way of "prevent[ing] the incurrence of penalties."

The RTO cited the order's statement that "bonuses and other incentives received by senior management could also be made contingent on penalty-free operations" and that in reviewing RTO filings, FERC will consider whether the RTO has implemented "personnel policies that place incentives on employees and management to comply with the rules or risk-adverse actions."

SPP said using the existing surplus to pay the reliability penalty "promptly" was an appropriate and reasonable action. "Doing so enabled SPP to pay the penalty in a timely manner as required without having to expend additional time, effort and resources to file for commission authorization to allocate the costs … prior to paying the penalty, and then invoicing and collecting the funds from the same entities who contributed to the 2017 surplus" through their payment of its administrative charges, the RTO said.

"The reduction of the funds that would otherwise have been paid to employees as compensation in 2018 was reflected as a surplus in 2018 that was part of the true-up required under Schedule 1-A, which reduced Schedule 1-A rates for 2019 by a comparable amount," SPP said. ■



SPP's headquarters in Little Rock, Ark. | *ACE Glass*

SPP News

SPP Seams Steering Committee Briefs

Revised Seams Study with MISO yet to Bear Fruit

SPP and MISO are finalizing evaluations of potential interregional projects and determining whether any can be mutually beneficial, SPP staff told the Seams Steering Committee last week.

However, it appears the 2019 Coordinated System Plan (CSP), which has been revamped to study seams transmission issues previously identified in the RTOs' regional planning processes, will be unable to identify any interregional projects. Two previous CSPs, conducted under different processes, failed to select interregional projects as well.

SPP Interregional Coordinator Adam Bell told the SSC on Wednesday that both parties have evaluated more than 50 potential interregional projects and shared possible solutions to resolve joint needs.

But only one project with noted issues by both RTOs' regional processes is still being analyzed. Three other projects with seams needs in either SPP's 2019 Integrated Transmission Planning (ITP) study or MISO's 2019 Transmission Expansion Planning (MTEP) process are still being evaluated.

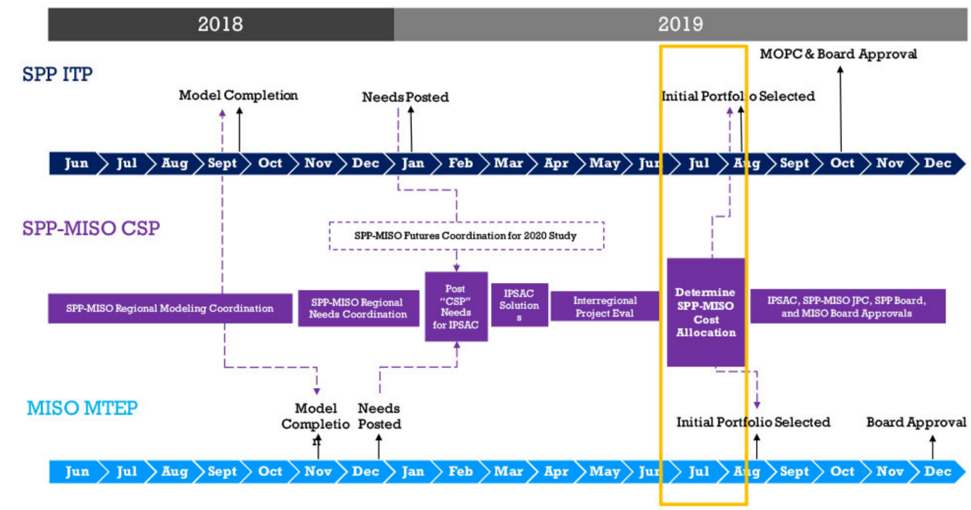
The 2019 CSP marks the first study since the RTOs agreed to revise the process last year. A proposal to remove a joint modeling requirement in favor of individual regional analyses and other changes to the MISO-SPP joint operating agreement was filed with FERC in May (*ER19-1896*). (See *MISO, SPP to Ease Interregional Project Criteria*.)

Initial stakeholder feedback was underwhelming.

"I'm just worried we'll be stuck in this situation every time we do one of these things going forward," Advanced Power Alliance's Steve Gaw said. "The problem has always been the regional model."

Adam McKinnie, Missouri PSC | © *RTO Insider*

"Different results were not an unanticipated outcome. This is exactly what we were afraid of," the Missouri Public Service Commission's Adam McKinnie said. "This should be something that both sides come up with an agreement on, yet we're back to the same process when we get to joint planning."



| *SPP*

Jeff Knottek, planning director at City Utilities of Springfield (Mo.), pointed to the Neosho-Riverton flowgate along the Kansas-Missouri border, a frequent constraint that has accounted for 40.8% of the market-to-market settlements between the RTOs ($26.9 million of $66.1 million since March 2015).

The congested flowgate was identified as a CSP joint need by both regional planning processes, but MISO's MTEP 19 results show negative or insignificant APCs, Bell said. None of the more than 25 solutions is being considered for approval in the CSP, he said. SPP is still regionally evaluating the flowgate.

"Obviously, [MISO's planning models] aren't reflecting operational reality," Knottek said. "The $26 million, almost $27 million on this one flowgate is not getting MISO's attention. Where do we go?"

"The joint planning process is absolutely an avenue we should look at it for addressing seams needs," Bell said. "SPP is showing significant benefits from resolving Neosho-Riverton. SPP is showing benefits to SPP for doing that."

"SPP needs to fix it, but I don't think we should pay for it ourselves," Knottek responded.

Bell said the conversation needs to be held at the RTOs' next Interregional Planning Stakeholder Advisory Committee *meeting* on July 31.

The lack of interregional projects between SPP and MISO is also likely to be a subject of conversation when the Seams Liaison Committee meets July 21 in Indianapolis during the National Association of Regulatory Utility Commissioners' Summer Policy Summit. The committee, composed of state regulators in both RTOs, is trying to improve the grid operators' interregional coordination.

M2M Settlements Reach $66M in SPP's Favor

MISO racked up a $3.6 million tab in May's market-to-market (M2M) settlements with SPP, pushing its overall bill to $66.1 million. It was the eighth-highest total for a month since the RTOs began the M2M process in March 2015.

Five permanent flowgates accounted for nearly $2.7 million of the total, binding for 315 hours. Temporary flowgates were binding for 835 hours, resulting in a $914,000 settlement to SPP.

An operations congestion management task force under the Operating Reliability Working Group has begun a general review of flowgates, "driven by a desire to better our practices," SPP's Will Ragsdale said.

The group is also looking at M2M power swings, he said, with the "main resolution" being updating the M2M software. ■

— Tom Kleckner

Company Briefs

AWEA Hires Morton to Lead Offshore Wind Advocacy

The American Wind Energy Association this month announced the hire of **Laura Smith Morton** to lead policy and regulatory efforts for the U.S. wind industry's rapidly emerging offshore sector.

In her new role as senior director, Morton will take the helm of AWEA's offshore wind program as the industry prepares to build its first large-scale projects off the Eastern seaboard. Morton has more than 10 years of experience in offshore wind policy and regulatory issues, both as an attorney and through senior roles at the Department of Energy, Council on Environmental Quality, and the National Oceanic and Atmospheric Administration.

More: *AWEA*

Orsted's Lincoln Clean Energy Buys 103-MW Wind Project in SD

Lincoln Clean Energy, a US unit of Ørsted, has purchased a 103-MW wind project in Butte County, S.D.

LCE acquired the project from Pattern Energy Group at an undisclosed price. The facility will be built in Butte County with its completion scheduled for the fourth quarter of 2020. The company has another project, the 230-MW Plum Creek wind farm in Nebraska, which is also expected to become operational next year.

More: *Renewables Now*

Revelation Energy Files for Bankruptcy Protection

Coal-producing company Revelation Energy and its affiliate Blackjewel have begun the bankruptcy reorganization process in the U.S. Bankruptcy Court for the Southern District of West Virginia.

Revelation listed 24 metallurgical coal mines and processing and prep facilities in Virginia, Kentucky and West Virginia as principal assets. The Appalachian mines have an estimated 600 million reserve tons of coal. The Energy Information Administration said in 2017 that the companies' combined output made them the country's sixth-largest coal producer.

According to court filings, Kentucky state officials are owed more than $6 million in taxes. In Virginia, officials are owed $1.6 million in taxes. The companies estimate they owe $156 million for goods and services across all properties.

More: *Ohio Valley Resource*

Federal Briefs

Chubb Bans Coverage for Coal, a 1st for Big US Insurance Firms

Insurance provider Chubb said it will no longer sell insurance to new coal-fired power plants or new policies to companies that derive more than 30% of their revenues from thermal coal mining.

The company, which is based in Switzerland but does a lot of business in the U.S., will also stop making new investments in companies that have a big exposure to thermal coal mining or coal-based energy production.

"Chubb recognizes the reality of climate change and the substantial impact of human activity on our planet," CEO Evan Greenberg said.

More: *Los Angeles Times*

FERC Sets Conference on Tx Line Ratings

FERC will hold a technical conference Sept. 10-11 to discuss dynamic and ambient-adjusted transmission line ratings.

The commission said the staff-led conference "will explore what transmission line rating and related practices might constitute best practices, and what, if any, commission action in these areas might be appropriate."

The commission announced the conference following its Notice of Inquiry on transmission incentives (*PL19-3*). Responding to the NOI, several commenters told the commission last month that it should incent transmission owners to use dynamic line ratings and other advanced technologies to increase the capacity of existing infrastructure. (See *Tx Incentives NOI Brings Calls for Broader Reforms*.)

More: *AD19-15*

Health Groups Sue over ACE Rule

The American Lung Association and the American Public Health Association are challenging EPA's American Clean Energy rule, the Trump administration's replacement for the Obama administration's Clean Power Plan.

"In repealing the Clean Power Plan and adopting the ACE rule, EPA abdicates its legal duties and obligations to protect public health under the Clean Air Act, which is why we are challenging these actions," the two groups said in a statement. "EPA has legal authority and obligation under the Clean Air Act to protect and preserve public health and welfare, including by regulating carbon dioxide pollution from coal-fired power plants. However, it is simply not lawful for EPA to use its legal authority in ways that will increase dangerous air pollutants and harm the health of Americans."

Trump's replacement rule is designed to give states more time and authority to decide how to implement new technology to lower net emissions from coal-fired plants. The administration argues the CPP was too extreme.

More: *The Hill*

Moody's says Climate Change Could Cost $69T by 2100

The consulting firm Moody's Analytics said climate change could inflict $69 trillion in damage on the global economy by the year 2100, assuming warming hits the 2-degree Celsius threshold.

Citing a report from the Intergovernmental Panel on Climate Change, Moody's said the warming of 1.5 C (2.7 F) would still cause $54 trillion in damages by the end of the century. The report predicts rising temperatures will "universally hurt worker health and productivity" and more frequent extreme weather events "will increasingly disrupt and damage critical infrastructure and property."

More: *The Washington Post*

Trump Slaps Tariffs on Solar Panels in Major Blow to Renewable Energy

The U.S. will impose tariffs of as much as 30% on solar equipment made abroad, a move that threatens to handicap an industry that relies on parts made abroad for 80% of its supply. The Solar Energy Industries Association has projected tens of thousands of job losses in a sector that employed 260,000.

The first 2.5 GW of imported solar cells will be exempt from the tariffs, President Trump said. The president approved four years of tariffs that start at 30% in the first year and gradually drop to 15%. He said the idea behind the tariffs is to raise the costs of cheap imports and "level the playing field" for those who manufacture the parts domestically.

More: *Time*

US Won't Impose Rule to Protect Against Coal Ash Spill Costs

The Trump administration said it will not require electric utilities to show they have money to clean up hazardous spills from power plants despite a history of toxic coal ash releases contaminating rivers and aquifers.

EPA officials also said that modern industry practices and recently enacted regulations are enough to shield taxpayers from potential cleanup costs. It comes after EPA reversed a related proposal under President Barack Obama that would have imposed new financial requirements on the hardrock mining industry.

Utilities and other companies in 2017 produced more than 111 million tons of coal ash, according to the American Coal

Ash Association. Much of the ash is recycled or used for industrial purposes such as concrete additives, but huge volumes end up in long-term storage. Coal ash disposal went largely unregulated until a 2008 spill at a Tennessee Valley Authority power plant dumped waste into two nearby rivers, destroyed homes and brought national attention to the issue.

More: *The Associated Press*

State Briefs

ARIZONA

APS Settles Claims for Customers who Died After Power Shutoff

Arizona Public Service, which has been sued twice in the last decade after customers died when their power was cut because they didn't pay their bills, has settled with the victims' estates in both cases. APS did not identify the customers or how much they owed.

One woman whose power was cut in June last year was found dead in her home in July, while another woman was found dead in December 2011 after APS cut her power in November. The utility disclosed the deaths in the wake of an additional fatality in Sun City West last fall when it cut off power to a 72-year-old who had been behind on her bills for five months.

State regulators have since enacted emergency rules barring most state electric utilities from disconnecting power to customers who are late on their bills from June 1 through Oct. 15, when soaring desert heat can be lethal.

More: *The Arizona Republic*

Regulators Close Complaint Against APS, Leave Rates Unchanged

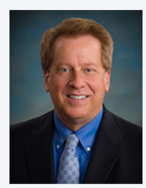
For the second time this year, utility regulators ended a challenge to a rate hike Arizona Public Service enacted in 2017 that drew thousands of customer complaints and a petition for a reconsideration. The decision means APS' rates will not change.

Rather than reverse the rate hike, the Corporation Commission voted 4-1 to uphold it and said it will address APS' rates in a new case it ordered the utility to file by Oct. 31. The four commissioners that voted to keep the rates said they were interested in ensuring the rates are fair to customers, but reversing the hike presented legal issues.

More: *The Arizona Republic*

ACC OKs New Limits on Campaign Contributions to Commission Candidates

The Corporation Commission approved a new code of ethics last week, including new limits on how much anyone with business before it can donate to candidates running for the commission.



The language crafted by Commissioner **Boyd Dunn** technically does not keep current and would-be commissioners from taking campaign money from utilities and others who are trying to convince the panel to approve or reject a pending issue. However, it does say if a commission candidate takes campaign money from someone who has business before the commission, they cannot vote on that matter when it goes before the panel.

More: *Tucson.com*

LOUISIANA

Entergy Louisiana to Raise Rates

Entergy customers in two sections of the state saw an increase in their electricity bills in June and will see another in September. The raises are for a new power plant and the fading effects of federal tax reform that had benefited customers. Together, the increases will lift customers' bills between $5.68 and $7.10/month depending on where they live.

The first increase is for the $869 million St.

Charles power plant that went online last month. The rate hike is expected to generate $109.5 million in one year. By September, customers will see another hike, which is tied to federal tax reform. Rates will go up between $2 and $4 as tax reform credits wind down, depending on where customers live, but the state can require a refund at a later date. The extra revenue collected would generate $118.6 million in the first year.

More: *The Advocate*

NEW YORK

Con Ed Apologizes for Manhattan Blackout

Consolidated Edison apologized on Sunday for a power failure that left a large part of the country's most densely populated urban area steaming in the dark for five hours, as utility executives and elected officials continued to seek an explanation for New York City's latest electrical shutdown.

Officials of Con Ed said there was "a significant electrical transmission disturbance" at 6:47 p.m. on Saturday that left 72,000 of its customers on the West Side of Manhattan without power until late into the night. But they provided scant insight into the underlying cause of the failure, which coincidentally came on the 42nd anniversary of one of the most infamous blackouts in the city's history.

The sudden loss of power disrupted service on several subway lines and shut down many of the city's most popular sources of entertainment, including Carnegie Hall and 26 Broadway theaters, and even cut off the performer Jennifer Lopez, mid-song, during a sold-out concert at Madison Square Garden.

More: *The New York Times*

SOUTH DAKOTA

Regulators Approve 2 South Dakota Wind Farms

The Public Utilities Commission has approved the construction of two wind farms that will produce up to 551 MW of power.

One project will be a 300-MW wind farm developed by Crowned Ridge Wind. The $400 million facility will cover 53,190 acres and include 130 turbines. It is expected to be operational by 2020.

The second project will be a 92-turbine farm in the central part of the state. The $300 million, 251-MW farm would cover about 27,000 acres in Hyde County.

More: *Kallanish Energy*

TEXAS

Xcel Energy Planning Refund for Customers

Xcel Energy customers will receive a one-time, $16 million refund in October related to several months of lower costs for natural gas used to fuel area power plants.

If approved by the Public Utility Commission, residential customers using 1,000 kWh/month would receive a one-time credit of $14.53. The refund will be based on the amount of electricity used in September. Customers also received a fuel-cost refund in January that amounted to $11.76 on a typical bill.

More: *KVII*

Longroad Secures Funds for 243-MW Wind Farm

Developer Longroad Energy Holdings has started building a 243-MW wind farm after reaching a financial close on the project.

Located in Knox County, the wind farm will be installed at a cost of approximately $335 million and will consist of 67 Vestas turbines ranging between 2 and 4.2 MW each. It is scheduled to become operational by July next year.

The project already has a power purchase agreement in place for 83 MW with DaVita, while 111 MW of its output will be sold to Crown Holding.

More: *Renewables Now*

WASHINGTON

Puget Sound Energy Steps Closer to Constructing 16-mile Tx Line

A Bellevue hearing examiner has ruled in favor of Puget Sound Energy's "Energize Eastside" project, bringing the utility one step closer to construction on a portion of a 16-mile power line project. The company says the project is needed to provide reliable power to people on the Eastside, which hasn't had a major upgrade to its system's capacity since the 1960s.

The ruling approved Pugent's conditional-use permit for one phase of the $150 million project that would build high-voltage lines from Redmond to Renton. The permit is limited to south Bellevue, where the utility hopes to build a new substation and add 3.3 miles of 230-kV lines.

More: *The Seattle Times*

WISCONSIN

Ratepayers to See Refunds Thanks to Lower Energy Costs in 2018

Four of the state's largest utilities will refund more than $25 million to ratepayers this fall as a result of lower-than-expected energy prices in 2018. Lower natural gas prices, the addition of renewable generation and a stronger wholesale electricity market were among the reasons cited for the savings.

Madison Gas & Electric customers should see the largest refund, which should range between $3 and $20 based on the rates approved by the Public Service Commission. Alliant over-collected about $4.9 million, which will result in refunds of about 0.5 cents/kWh. Wisconsin Public Service and Xcel Energy reported over-collections of $7.1 million and $3.7 million, respectively, and will issue refunds of about 0.9 cents and 0.7 cents/kWh, respectively.

More: *Wisconsin State Journal*