RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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CAISO Declares Emergency as Fire Derates Major Tx Lines

By Hudson Sangree and Robert Mullin

CAISO declared a Stage 2 energy emergency Friday evening as an out-of-control wildfire in Oregon nearly shut down one of two major transmission pathways between California and the Pacific Northwest while significantly reducing transfer capacity on the other.

By Saturday morning, the Bootleg Fire in south-central Oregon had doubled in size to 77,000 acres and was burning under the Pacific AC Intertie (PACI), three parallel

Continued on page 11

The fast-moving Bootleg Fire in Oregon derated the California-Oregon Intertie Friday. | *U.S. Forest Service*

Is Decarbonization an 'Existential' Challenge for RTOs?

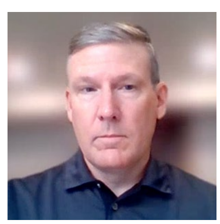
Clark, Duane See 'Post Marginal Price' World

By Rich Heidorn Jr.

Vince Duane spent almost 17 years as general counsel at PJM, the nation's biggest RTO. But he now says the RTOs' market model — based on single-price clearing auctions and locational marginal prices — no longer works in a world of renewable resources with little or no operating costs that don't respond to price signals.

Former PJM General Counsel Vince Duane | © *RTO Insider LLC*

In a new *paper* Duane and former FERC Commissioner Tony Clark, a senior adviser for law firm Wilkinson Barker Knauer, challenge what they call the "the prevailing orthodoxy … that the road to the decarbonized, advanced technology grid of the future goes through a Regional Transmission Organization." Duane, ousted from PJM in the wake of the GreenHat Energy default, is now principal of a consulting firm, Copper Monarch.



Former FERC Commissioner Tony Clark | *© RTO Insider LLC*

"The cracks in the foundations of RTOs are not

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Consumer Groups Seek Congressional Study of Organized Markets (p.9)

PJM Board Approves MOPR Rollback

| *U.S. Department of Agriculture*

By Michael Yoder

The *PJM* Board of Managers on Wednesday approved the RTO's proposed replacement for the extended minimum offer price rule (MOPR-Ex), setting up a final decision on the contentious capacity market issue at *FERC*.

At a special Members Committee meeting last week, stakeholders strongly supported PJM's *proposal* in an 87-18 vote, for a sector-weighted score of 4.18/5. The PJM proposal was one of nine proposals voted on at the meeting but the only one to receive majority support. (See *Stakeholders Back PJM MOPR-Ex Replacement*.)

In a letter issued by the board on Wednesday,

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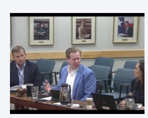
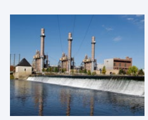


PUC Debates Answers to ERCOT's Reliability Issues (p.12)



Discord Persists over MISO Seasonal Capacity Accreditation (p.16)

MISO, SPP Solicit Ideas on Allocating Joint Tx Costs (p.27)

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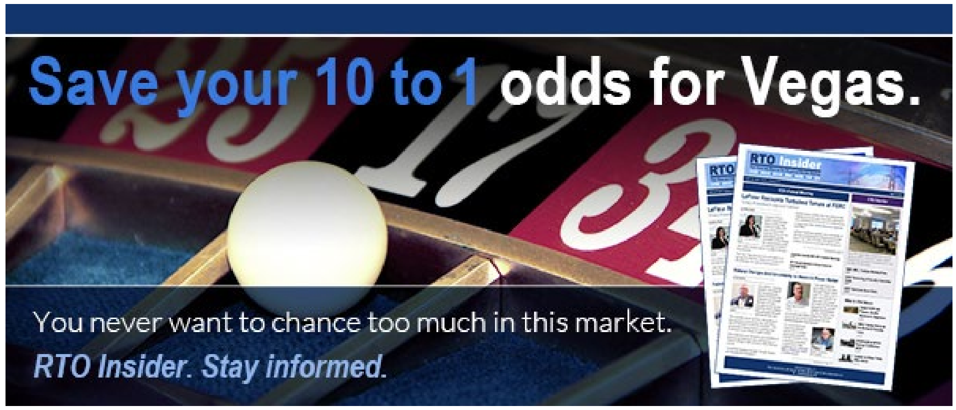
***NetZero Insider* is now live!**
See p.20 for this week's coverage.

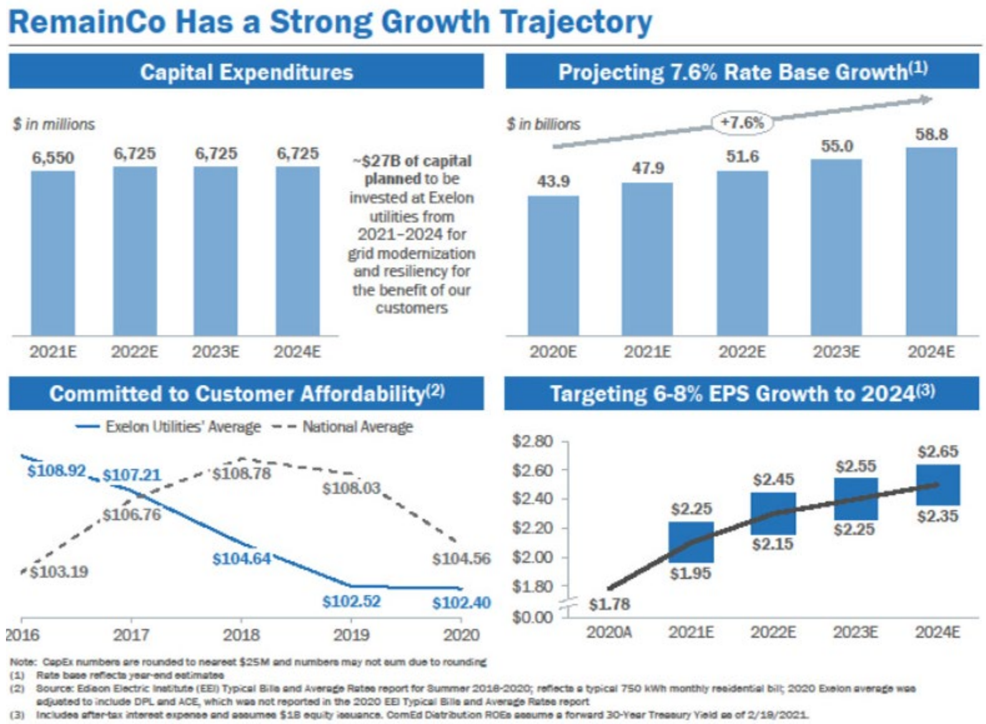


Counterflow

By Steve Huntoon

New Ball and Chain for Renewable Energy

More than 20 years ago it was agreed in PJM, and approved by FERC, that new generators would pay the full capital cost of transmission system upgrades (network upgrades) needed for interconnection.[1] That was, and remains, one of the cornerstones of PJM. It's a basic "but for" test that ensures, as FERC observed more than 20 years ago, that the most economic generation is interconnected.[2]



| Exelon

The New Ball and Chain

The PJM transmission owners have now proposed to FERC to eliminate that and replace it with a TO option to rate base the cost of such upgrades and charge every generator a monthly formula rate for 20 years (*ER21-2282*). Generation interconnection customers would face the double whammy of putting up security for the full capital cost of network upgrades, while *also* paying the monthly formula rate for 20 years.[3]

The analogy to utility service for retail customers would be customers having to put up security equal to *pro rata* shares of total utility rate base, while *also* paying the utility monthly bill with an embedded return on rate base for the next 20 years.

Needless to say, the PJM TOs' proposal would compound the costs and risks of interconnection, with adverse consequences for new wind and solar projects.

PJM Tariff Violations

The PJM TO proposal violates the PJM tariff. Since at least 2007, the PJM tariff has stated: "No Network Upgrade … shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned."[4]

Because the PJM TO proposal would rate base network upgrades, such upgrades could no longer be Customer-Funded Upgrades for which a generator could have "cost responsibility."[5] Thus, PJM and the PJM TOs could not impose cost responsibility upon generator customers — violating the fundamental principle of "but for" cost responsibility. And begging the question, if generators do not pay for network upgrades, who does?

Moreover, in one fell swoop the PJM TOs would strip generators of the financial rights (Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights and Incremental Capacity Transfer Rights) that they are entitled to from network upgrades they pay for. The PJM tariff does not allow generators to receive financial rights for rate-based network upgrades.[6] Taking away those rights would violate the PJM tariff, and the many FERC orders accepting and approving these rights over the last 20 years.[7]

The Commission has succinctly summarized both rules: "PJM's tariff provides that a customer cannot fund upgrades and cannot receive financial rights for projects that are included in a utility's cost-of-service."[8]

Nowhere do the PJM TOs explain how they can unilaterally eviscerate these PJM tariff provisions approved by the Commission.

Perverse Incentive Created

The PJM TO proposal would create a perverse incentive for TOs to inflate the scope and costs of network upgrades in order to inflate rate base. Generation interconnection customers would be in weak position to defend against inflated scope and costs because of the TO near monopoly on critical system information and because the consequence of resisting inflated scope and costs would be project delay or failure.

A Windfall for Existing TO Affiliated Generation

Raising interconnection costs and risks, and piling on the perverse incentive to inflate scope and costs, discourages new entry and thus provides a windfall for existing TO-affiliated generation. It would be highly inequitable to reverse a 20-year cornerstone of PJM to provide a windfall for TO-affiliated generation. This is independent of whether TOs also would discriminate in favor of their *new* affiliated generation.

PJM TOs' Nonexistent Risks

The PJM TOs' arguments for their proposal are insubstantial in theory and unsubstantiated in reality.

The gist of their case for changing the paradigm of the last 20+ years is that they face "untenable financial pressure" from increased risks because of an increase in network upgrades because of increased generation interconnections, principally renewable energy generation (page 8). Surely such an existential threat would be disclosed to shareholders in

Counterflow

By Steve Huntoon

SEC filings. Nope. Not there.[9]

And, in fact, new network upgrades paid for by interconnection customers *decrease*, rather than increase, virtually all of the risks listed by the PJM TOs. Let's take "operational and safety risks" where the PJM TOs cite "transformer fires at substations" (page 14). In this case the relevant network upgrade would be replacing an older, smaller transformer with a new, larger transformer which would of course *reduce* fire risk.

The PJM TOs do not identify a single event associated with network upgrades, among the many thousands of them over the last 20 years, that caused a loss to TO shareholders.

And as for transmission risks generally, the PJM TOs provide no examples of actual loss to shareholders and a paucity of events that somehow could have produced such a loss. The totality of their specific events are:[10]

- Dump truck drove through 230-kV tower.
- Fighter jet pilot ejector seat nicked 230-kV line.
- NERC imposed $2.5 million in penalties in 2020 (across the entire country).
- A switching station was built on contaminated land.[11]
- Hurricane Isaias caused an outage to 50,000 customers lasting five hours.
- A tornado might have caused 3,798 customers to lose power (but didn't).

In other words, risk is basically nil.

PJM TOs Ignore Insurance

Under the interconnection service agreements in the PJM tariff, PJM TOs are required to carry commercial general liability insurance of not less than $1 million per occurrence and excess/umbrella insurance on top of that of not less than $20 million per occurrence.[12] The PJM TOs don't mention insurance, much less explain why insurance wouldn't cover any risks.

PJM TOs' Business Model

The PJM TOs claim that owning and operating facilities that are not rate based adversely affects the TOs' "business model" (pages 14-15). This "business model" was agreed to by the PJM TOs more than 20 years ago. After 20 years investors know — or should be presumed to know — what they are and are not investing in.

A review of the largest TOs' presentations to shareholders this year reveals rosy claims of continued growth in rate base and similar metrics.[13] Here is Exelon (NASDAQ:EXC) telling shareholders of its "Strong Growth Trajectory" for the utility business, and projecting future utility rate base to increase 7.6% per year, along with a 6-8% increase per year in earnings per share.[14]

Wrong Denominator for Alleged Risks

The PJM TOs say that if the historical percentage of network upgrades actually built is applied to projects in the PJM queue, and added to past network upgrades, that the total dollars would be about 4% of PJM TOs' current combined net transmission plant (page 18). They call this a "material and significant portion of transmission assets." Assuming, for the sake of argument, that past network upgrades should be counted, and that there are actual risks to shareholders associated with network upgrades, the PJM TOs have used the wrong denominator. The significance of any risk to shareholders is relative to total utility rate base, not just transmission.

With few exceptions, shareholders do not invest in transmission by itself. The Exelon slide shows that Exelon reports total rate base to shareholders. Taking Commonwealth Edison, the largest Exelon utility subsidiary as an example, its transmission plant is only 19.2% of its total utility plant — the lion's share is distribution plant.[15] Using Commonwealth Edison as a go-by, the PJM TOs' 4% of transmission is less than 1% of total utility plant (19.2% of 4%). Tiny.

Assuming TO Risks to be Alleviated by this Filing, TO Rates of Return Should Be Commensurately Reduced

Assuming for the sake of argument that there is some material risk associated with network upgrades, there should be a commensurate and concurrent reduction in the TOs' authorized rate of return if FERC were to relieve TOs of that risk.

In Conclusion

Renewable energy has enough challenges without adding this one. ■

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[1] PJM Interconnection, L.L.C., 87 FERC ¶ 61,299, at page 17 (1999) ("…generators will be required to pay the full cost of grid expansion…").

[2] Id. ("… this type of proposal forces the developer to consider the economic consequences of its siting decisions when evaluating its project options, and should lead to more efficient siting decisions.").

[3] Transmittal Letter, page 27, and section 4 of the proposed Network Upgrade Funding Agreement.

[4] Tariff definition of "Customer-Funded Upgrade, then section 1.7A.01, filed December 18, 2006, in PJM Interconnection, L.L.C., Docket No. ER07-344-000, accepted by Letter Order issued February 8, 2007.

[5] Id. ("Customer-Funded Upgrade" shall mean any Network Upgrade … for which cost responsibility (i) is imposed on an interconnection customer…")

[6] Tariff sections 231.6, 233.6, and 234.6.

[7] Starting with the PJM filing in PJM Interconnection, L.L.C., Docket No. ER00-941-000 (December 29, 1999), accepted by letter order dated March 30, 2000. A recent FERC order involving a generator's incremental capacity transfer rights is Radford's Run Wind Farm, LLC. v. PJM Interconnection, L.L.C., 171 ¶ FERC 61,025 (2020).

[8] PJM Interconnection, L.L.C., 153 FERC ¶ 61,286 at P 25 (2015).

[9] Exelon, which provides the affidavit for the PJM TO filing, says nothing in its most recent SEC form 10-K filing about supposed increased risks from increased network upgrades. https://investors.exeloncorp.com/static-files/ab8f2e58-fb68-4f1c-9197-bdca30371726 (pages 30-46).

[10] Affidavit of David W. Weaver, P.E., pages 10, 14, and 20.

[11] This is not identified as a material risk in the most recent SEC form 10-K of Public Service Electric and Gas Company (NYSE:PEG), https://www.ezodproxy.com/pseg/2021/10k/images/PSEG-10K2020.pdf, pages 136-142.

[12] Attachment O, Interconnection Service Agreement, Appendix 2, sections 13.1 and 13.2; Attachment P, Interconnection Construction Service Agreement, Appendix 2, sections 11.1 and 11.2.

[13] E.g., Dominion Energy (NYSE:D) forecasts 13% compound annual rate base growth over next five years for Dominion Energy Virginia. https://s2.q4cdn.com/510812146/files/doc_financials/2020/q4/2021-02-12-DE-IR-4Q-2020-earnings-call-slides-vTC1.pdf, slide 18. AEP (NASDAQ:AEP) forecasts 7.4% compound annual rate base growth over next five years for its utilities. https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/JPMConferencePresentation06-22-21.pdf, slide 21.

[14] https://investors.exeloncorp.com/static-files/378e54d7-56c0-46e2-a73b-744501822ec0 (slide 14).

[15] Commonwealth Edison Company, FERC Form 1 for 2020, page 207, lines 58 and 100.

FERC/Federal News

NREL: International Tx Critical for Emission Reductions, Resource Adequacy

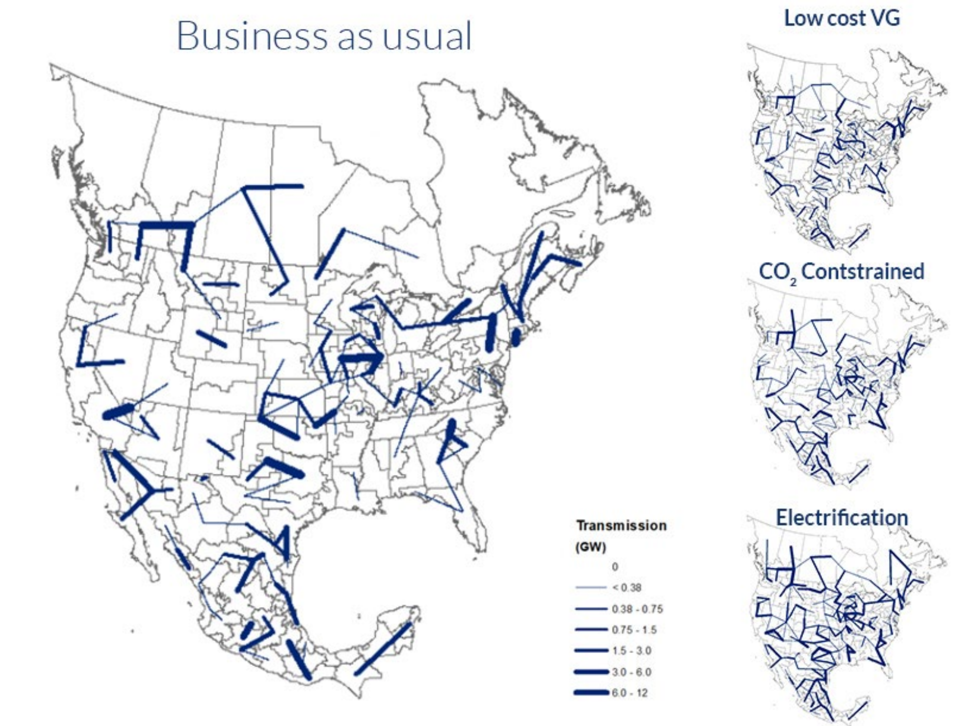
By K Kaufmann

A new study from the National Renewable Energy Laboratory says that the most effective way to cut at least 80% of greenhouse gas emissions from North America's power systems by 2050 will be to put as much low-cost wind and solar on the grid as possible, electrify everything, and build hundreds of gigawatts of new transmission capacity.

The North American Renewable Integration Study (*NARIS*) also envisions a small but significant amount of those new transmission lines running across U.S. borders with both Canada and Mexico.

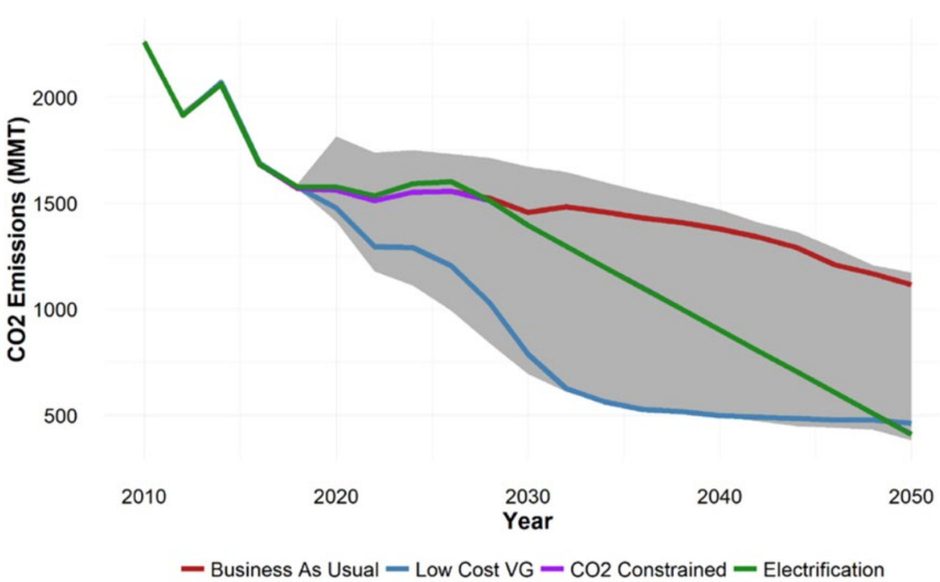
"Our big-picture, take-home messages are that we can maintain [resource] adequacy while going to these high [renewable] contribution scenarios," said Gregory Brinkman, a senior engineer at NREL and principal investigator on the study. Another key takeaway: "Cooperation and transmission expansion are really, really valuable," he said.

Brinkman said such findings are not particularly unexpected or shocking. Rather, the value of the report lies in its efforts to look at North America's power systems holistically and its extensive modeling of the opportunities for system efficiencies and cost savings that may be available with different low-cost renewable, emission-reduction and electrification scenarios, and the transmission buildouts each will require.



The core scenarios in the NARIS report show that the cleaner the power, the more new transmission will be needed. | *NREL*

For example, the study finds that ramping up low-cost wind and solar over the next decade could provide deeper cuts in carbon emissions in the near term than either targeting an 80% drop in carbon emissions or electrifying transportation.



Ramping up low-cost wind and solar is the quickest, most effective way to cut carbon emissions, according to the NARIS report. VG = variable generation. | *NREL*

The report also estimates net benefits of new cross-border transmission at $10 billion to $30 billion between 2020 and 2050, based on total capital and operational costs, Brinkman said. The corresponding benefits of building out interregional transmission in the U.S. could pencil out at $60 billion to $180 billion, the report says. Those benefits do not include "externalities" such as the social and health benefits of lower emissions, Brinkman said.

The report, which includes parallel U.S. and Canadian versions, was released alongside a memorandum of understanding on cross-border cooperation signed at a June 24 meeting between U.S. Energy Secretary Jennifer Granholm and Canadian Minister of Natural Resources Seamus O'Regan. The *nonbinding MOU* includes a long list of potential areas for "sharing knowledge and exploring options" and best practices, such as vehicle electrification, grid reliability and cybersecurity, and improving energy access and resilience for remote and Arctic communities.

While the MOU commits neither country to providing any funds for collaborative projects or to even regular meetings, it is founded on mutual interests and needs that will likely intensify in the coming decades.

FERC/Federal News

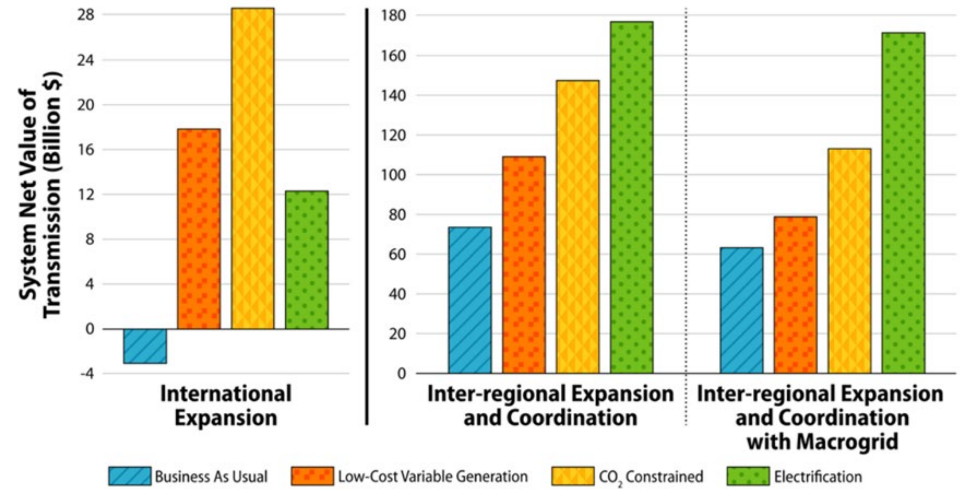
"No two countries in the world have their energy sectors as closely linked as Canada and the United States do," O'Regan said in a joint announcement of the MOU, emphasizing the economic benefits of cross-border energy exchanges between the two countries. According to the *U.S. Energy Information Administration*, Canada is the largest energy supplier to the U.S. and, after Mexico, the second largest market for U.S. energy exports.

In dollar terms, EIA pegged U.S. energy imports from Canada at more than $80 billion in 2019, about four times the exports from the U.S. to Canada.

Granholm framed the MOU as a bilateral commitment to "ensure that all pockets of North America have access to affordable, clean energy. We can't tackle the climate crisis alone," she said. "We must work together to accelerate the flow of low-carbon electricity across our borders."

Exactly how much energy will be crossing borders and how much transmission will be needed to ensure reliability and resource adequacy are more difficult to gauge. One of the weaknesses of the report is that it measures new transmission in terms of megawatts of capacity, not miles. Putting low-cost solar and wind on the grid could require about 100 GW of new capacity on the transmission system versus 200 GW required for electrification of buildings and transportation.

New wires going between Mexico and the U.S. would only need 3 to 8 GW of capacity, and U.S.-Canada lines would need 10 to 20 GW, the report says. Mapping out new transmission needed to increase renewables, cut emissions and electrify buildings and transportation, the report shows an increasingly thick web of new lines connecting regions across the U.S. itself.



Building new international and interregional transmission could provide up to $180 billion in net benefits. | *NREL*

Slightly Outdated Data

The self-acknowledged limitations of the NARIS report are significant, as seen in the four basic scenarios it covers.

The business-as-usual pathway is based on state and federal legislation enacted as of October 2018, meaning many of state emissions-reduction targets enacted in the past three years are not part of the modeling. Similarly, the low-cost variable generation (VG) scenario uses 2018 prices to model the costs of its high penetrations of wind and solar, again not capturing the ongoing cost reductions.

It is also the only model to envision a growing role for distributed rooftop solar, 160 GW by 2050 versus 60 GW in all other options.

The report's carbon-constrained scenario works not toward a 2050 target of net zero emissions, but an 80% target in the U.S and Mexico and 92% in Canada. As a result, gas-fired generation remains online even in the report's most aggressive pathway for electrifying transportation and building energy consumption. NREL's Brinkman said the gas generation there, and in the business-as-usual and low-cost VG models, would be primarily for backup power.

Another problem: The scenarios' modeling of solar and wind output is based on weather data from 2007 to 2014, and the impacts of climate change, or the extreme weather events of recent years, are not included.

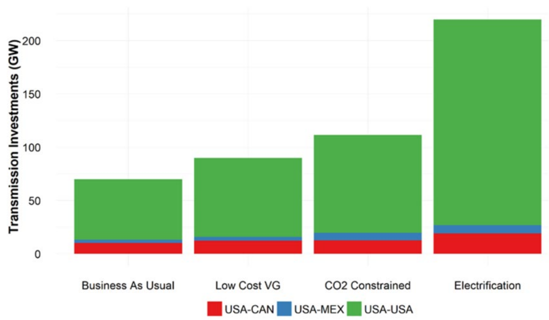
Brinkman said the decisions on weather inputs were based on the need for "high-quality data," defending the report's findings as "robust" and not likely to change with future research.

"Climate change is really tough to model in terms of its impact on potential demand patterns and also potential wind and solar patterns," he said. "It's really important that we get all three of those things consistent with each other, because they are highly correlated."

But the impacts of climate change could also affect the role of hydropower in the different scenarios, especially in Canada, where hydro is one of the country's primary sources of exportable renewable power. Drought in the Western U.S. has already cut hydropower resources there — the *Hoover Dam* is currently running at about 66% efficiency — and similar reductions could occur in Western Canada.

At the same time, *one study* shows increased precipitation and snow melt could boost hydropower output in the eastern part of the country. Such an increase could bode well for a new transmission line, the *Champlain Hudson Power Express*, being developed to bring up to 1,250 MW of hydro power from Quebec to New York. The Canadian government also recently issued a final permit to begin construction of its portion of the *New England Clean Energy Connect* transmission line, which would bring hydro from Canada across Maine and into Massachusetts.

Both international and interregional connections will be essential for resource adequacy going forward. By 2050, the report shows such transmission will be critical for most U.S. grid operators to meet power and capacity shortfalls. More than 150 TWh of power could be moving across the Canadian-U.S. border, in both directions, the report says. In the low-cost VG scenario, for example, 32% of energy exports are from the U.S. to Canada. ■



The most aggressive electrification scenario could require new transmission with up to 200 GW of capacity, most of it in the U.S. | *NREL*

FERC/Federal News

Is Decarbonization an 'Existential' Challenge for RTOs?

Clark, Duane See 'Post Marginal Price' World

Continued from page 1

just cosmetic," they write, saying "regulators and the RTOs themselves need to reassess wholesale markets from the ground up as the electricity delivery system transitions to a grid much different from the one of the past."

The authors explicitly challenge nine former FERC commissioners who wrote a joint *letter* last month urging the commission to expand organized markets to the West and Southeast to aid decarbonization efforts and save ratepayers money. "Organized markets are more essential than ever as our nation decarbonizes the power sector," they wrote. "As the pace of decarbonizing the grid accelerates, we are convinced that the time for organized market expansion is now." (See *Ex-FERC Officials Urge Commission to Expand Organized Markets*.)

Clark and Duane don't dispute "the rationale behind the original RTO paradigm, and its historic benefits." They also agree that the grid will continue to see increases in renewable energy and that the footprints of the largest RTOs and ISOs are helpful to maximizing the value of such assets.

But they say they disagree with "unbridled RTO boosterism" because the markets' model is "misaligned with public policies that seek to advance grid decarbonization."

They cite "lethargic interconnection queues offering little cost predictability [and] capacity markets that frustrate a state's policy preference to increase renewable resource penetration."

RTO markets are constrained, they say, by their inability to tolerate shortages, demand's limited responsiveness to price signals, structural market power and the "non-linear economics and idiosyncratic behavior" of generators with different operating characteristics and performance parameters.

Single-clearing price auctions assume that electricity is a commodity, with one kilowatt hour fungible to the next, they note. But that assumption no longer holds, they contend, with renewables' insignificant operating costs and intermittence.

They are also critical of RTO price formation, saying it "combines abstract art with impenetrable science."

Both inflexible baseload nuclear plants and

Former FERC Commissioner Tony Clark and former PJM General Counsel Vince Duane answers questions about their paper challenging the RTO model in an *interview* with *RTO Insider* Editor Rich Heidorn Jr. | © *RTO Insider LLC*

wind and solar plants act as price takers.

Other inflexible plants, such as those with minimum commitment blocks, are ineligible to set clearing prices.

"Taking this liquidity off the table means that LMP outcomes are not as competitive as many might assume," leaving fossil units, usually natural gas, to set clearing prices, they write. Ironically, they say, "in order for a renewable resource to obtain positive revenue from selling its energy in an RTO market, it must rely on a carbon-emitting fossil resource to set a positive LMP."

Yet RTOs depend on price signals to ensure sufficient supply to maintain reliability. "Having a supply stack that effectively thumbs its nose at price" undermines that construct, they say. "Non-dispatchable intermittent resources will inject energy when it's sunny or windy without regard to the RTO's price signal.

"What happens when price is no longer an effective tool for fulfilling the tasks that RTOs were created to complete?" they ask. "If an increasing portion of the grid is characterized by socialized fixed charges and generation that neither sets prices nor responds to price signals, the impact will be profound."

They cite "lethargic interconnection queues offering little cost predictability [and] capacity markets that frustrate a state's policy preference to increase renewable resource penetration."

—Former FERC Commissioner Tony Clark and former PJM General Counsel Vince Duane

They acknowledge that "breakthroughs in storage technology, or a very different paradigm for participation of demand … might save the RTO's single-clearing price auctions." But they are dubious, contending that "direct retail 'price responsive demand' has, by and large, never lived up to its promise."

And while they cite the "pragmatic appeal" of

FERC/Federal News

having RTOs centrally plan transmission for areas best suited for wind or solar generation, they say it "upends a lot of the design purpose of LMP."

"Does this mean RTOs can't serve as a vehicle to advance decarbonization? No. But we are inclined to think RTO wholesale electricity markets, which are a defining feature, will have to be re-thought from the ground up," they write. "This isn't going to come easily or quickly — particularly considering structural and governance features of the RTO," a subject they promise to explore in a future paper.

"Given these existential challenges to the RTO model," they write, "policy makers should be cautioned against embracing RTOs as the only way to achieve future energy goals, especially in the absence of an identifiable fix to their structural weaknesses."

Q&A

Clark and Duane answered questions about their paper in a July 12 interview with *RTO Insider* Editor Rich Heidorn Jr. Here are some of the highlights, edited for clarity and brevity.

RTO Insider: *You explicitly challenge nine former FERC commissioners who wrote a joint letter last month urging the commission to expand organized markets to the West and Southeast to aid decarbonization efforts and save ratepayers money. The former officials wrote that "more than 80% of renewable generation has been deployed in the organized market regions, and emissions are falling faster in such regions." That seems like a counterfactual to your thesis. Why are they wrong?*

Tony Clark: Well, I think they're wrong for a number of reasons. … Simply expanding a model, which is really struggling under the weight of the grid transition as it's happening right now, would seem to be problematic. But secondly, I don't know that I would necessarily agree with the underlying assumption that it's RTOs that had been responsible for [the growth of renewables]. I think state public policies are a big part of it. Some of the mega trends that are in the industry are part of it. But if you look outside of the organized markets, you see a lot of retention of things like nuclear power … which is very difficult to do in some of the more restructured regions.

… I'm certainly not anti-RTO at all. I mean, I had authorized some of my utilities to join them when I was on the [North Dakota Public Service] commission. But I think there's also an understanding that they arise out of particularly historical context, and there are reasons that certain areas of the country for reasons of geography and market construct and resources that they had available, haven't joined to this point. And it would seem to me to be a mistake to simply mandate that that model be spread everywhere. And in fact, that will probably just become a flashpoint in the FERC-state relationship, if it were to happen.

RTO Insider: *Some might say that you guys are carrying water for the monopoly utilities, such as those that are supporting the Southeast Energy Exchange Market. So I have to ask you this: Was this funded in part or in total by any of WBK's, or Copper Monarch's clients? And if so, who?*

Tony Clark: In terms of clients, we, of course, don't disclose our client list. I would say in terms of why we write things like this, we hope it's provocative; we hope that it starts a discussion — a needed discussion — and hope it's taken in that vein.

Vince Duane: These are very much thoughts that I have had for quite a few years. And I think any of my … former colleagues at PJM, at the executive level would say, "Yeah, that sounds a lot like what Vince has been talking about for quite a while now." I have spent 17 years of my life working with the organized markets. And I think there's a particular genius associated with locational marginal pricing. And what troubles me most is that we seem to have forgotten just how central price is to the RTO functions, not just the market and economics, but even controlling day-to-day security. … And it has distressed me for quite some time seeing us chip away at that. … We just have to ask ourselves a very honest question, which is: Are we going to continue to adhere to this form of competitive model? And if so, can we realistically expect it to survive in light of the policy directions we're taking? And it's not just about pursuing renewable resources, it's about the way we're pursuing them, which is to support and subsidize. If we were having a discussion about carbon pricing at a federal level and the RTO model, I think you'd get a very different answer, at least from me.

> **"If an increasing portion of the grid is characterized by socialized fixed charges and generation that neither sets prices nor responds to price signals, the impact will be profound."**
>
> —Former FERC Commissioner Tony Clark and former PJM General Counsel Vince Duane

RTO Insider: *I was just about to ask you about that. Your paper is about 7,000 words long … yet, there's not even a single mention of carbon pricing, which some say would address the RTO-climate disconnect. Why did you not address that?*

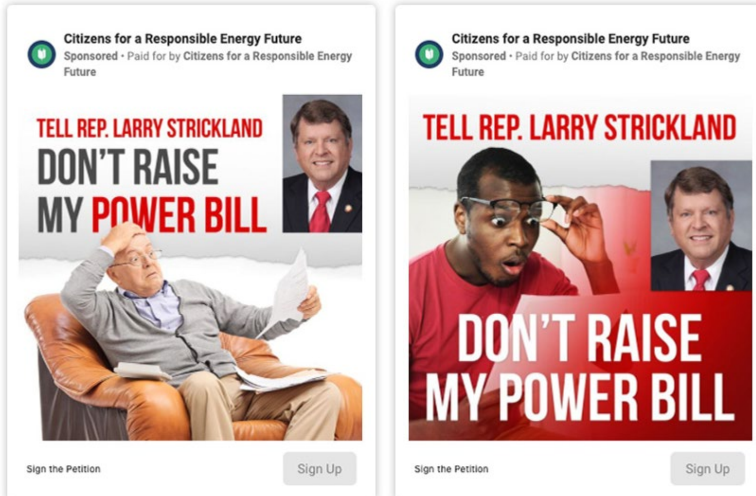
Vince Duane: It was perhaps a bit of a myopic focus, on my part, anyway, on the direction that policy has been heading, both at the state and at the federal level, and at the regulatory level with the commission in Washington over the last several years. And while there has been talk about carbon pricing — and I think there's a widespread view as to the logic of it — there's also, I think, a widespread perception that for political practical reasons, what have you, it's just not as an attainable objective in the short-to medium-term. But you know, you're correct … I would say, we would be having a very different discussion about ISO/RTO markets and the overall model, if we were talking about carbon pricing.

Tony Clark: It does strike me that if carbon pricing is to be the policy and incorporated into the RTOs … you would need to then strip away some of the other sort of out-of-market constructs and subsidies and things like that. I personally don't know that just layering a price on carbon, on top of a quote-unquote "market" that is riven with a lot of other distortions really accomplishes what you hope it would do. It would just add a price on a really complicated market that doesn't need any more complexity and may not fix the underlying problem.

Vince Duane: I would just prefer to see the ISOs carry a much more straightforward message than, frankly, I believe they have, which is a message that says we need to be talking about carbon pricing … because our efforts to accommodate the supportive mechanisms and subsidy mechanisms that create non-bypassable charges and distort price have fundamental and unsustainable implications to what we think you all liked about ISOs, which was the ability to run a central, non-discriminatory open dispatch and harness competitive forces and put risk on those that are best able to manage. That's the kind of thing that's in the balance. And it distresses me that ISOs have become, I think, so wary of expressing that kind of opinion that you don't hear it. So I've kind of enjoyed the opportunity, post-PJM in my career, to be able to say some of these things, because … at the end of the day, we want to see a debate on these issues, because we think they're being swept under the rug. ■

Consumer Groups Seek Congressional Study of Organized Markets

By Rich Heidorn Jr.



Duke Energy has supported Citizens for a Responsible Energy Future, a group fighting legislation proposed by North Carolina Rep. Larry Strickland (R) that would direct the North Carolina Utilities Commission to study potential power market reforms. | *Citizenz for a Responsible Energy Future*

Eleven public interest and consumer groups asked congressional leaders Thursday to order an independent study of FERC policies on wholesale markets, saying regulators need to understand the "relationship between market structure and the cost and reliability of electricity."

The groups said there is no objective data on the impact of FERC's policies, begun more than 20 years ago, to open wholesale markets to competition. "Many states also expanded competition at the retail level in search of consumer savings. This was a bold and unprecedented experiment in electricity regulation, but the impacts on customer bills appear to have been mixed," the groups said, citing a 2015 *working paper* by the National Bureau of Economic Research (NBER).

The paper concluded that electricity restructuring improved generation efficiency, but that "electricity rate changes since restructuring have been driven more by exogenous factors — such as generation technology advances and natural gas price fluctuations — than by the effects of restructuring."

The groups — including the R Street Institute, Electricity Consumers Resource Council (ELCON), Public Citizen, industrial customers in Pennsylvania and Louisiana, and conservative groups such as *Heritage Action for America* — said the study should be conducted by the Government Accountability Office (GAO) "or other independent oversight organization" and that Independent Market Monitors for each RTO and ISO should also be involved. The request came in a *letter* to the chairs and ranking members of the Senate Committee on Energy and Natural Resources and the House Committee on Energy and Commerce.

In 2008, GAO called on FERC to do more to analyze RTO benefits and performance, *reporting* that "there is no consensus about whether RTO markets provide benefits to consumers or how they have influenced consumer electricity prices."

The groups said when they asked FERC for a meeting on the issue, "FERC staff replied that 'the commission is not inclined at this time to commission that type of broader study.'" A FERC spokesperson declined to comment.

Although FERC has issued several reports on RTO *performance metrics* between 2010 and 2017 and NBER has *reported* that RTOs reduce production costs, "these lines of analysis are incomplete and do not address the central question of the impact of RTOs on customer bills," the groups said.

"We need regulators who base their policy decisions on objective data and real-world impacts rather than assumptions by advocates," they said. "The study we request should investigate the cost impacts of federal policy regarding market structure, namely the net benefits to retail consumers resulting from the formation of Regional Transmission Organizations (RTOs) and Independent System Operators. At minimum, it should examine how existing RTO market structures have impacted the cost of electricity to retail consumers. We also ask that the study explore the reliability impacts of wholesale market structure and, if resources allow, develop a set of best practices regarding RTO expansion."

Potential RTO expansion in the West and Southeast and efforts to decarbonize the grid and electrify transportation "make it more important than ever that policymakers investigate the impacts of wholesale market policies on retail customers now," they wrote.

They cited Duke Energy's financing of a *public relations campaign* opposing a Southeast RTO as a "Really Terrible Option" that would raise customer's bills.

Duke (NYSE:DUK) is one of the utilities that asked FERC in February to approve the Southeast Energy Exchange Market (SEEM), an expansion of existing bilateral trading, as an alternative to an RTO. (See *Clean Energy Groups Pan Southeast Utilities' SEEM Proposal*.)

"The assertions made by both sides can and should be examined objectively using real-world data," the letter said. "If both sides are right about the economics — that is, if there are substantial production cost savings from RTOs at the wholesale level, yet retail customer bills in RTO regions continue to climb — then Congress, FERC and the states owe it to consumers to understand the disconnect and address it."

The group said the variation among market structures in the U.S. — including utilities subject to traditional monopoly regulation, municipal and cooperative utilities and federal power marketing administrations — "presents a great opportunity to study the pros and cons of different arrangements."

PJM and MISO each have reported savings of $3 billion to $4 billion annually, while SPP has put its savings at more than $2 billion. CAISO has estimated more than $1 billion in savings through its Western Energy Imbalance Market since 2014.

"Government studies published more than a decade ago regarding wholesale markets claimed to lack the necessary data," ELCON CEO Travis Fisher said in a statement. "The time is right to revisit these issues with fresh data so we can have an informed debate about the impacts of wholesale markets on consumers." ■

Drought Puts Hoover Dam Hydropower at Risk

Southwest, California Suffer from Historically Low Reservoir Levels

By Hudson Sangree

Prolonged drought is threatening hydropower production throughout the West, including at the iconic Hoover Dam on the Colorado River, which provides power to Las Vegas and other cities in Arizona, California and Nevada.

The level of Lake Mead, behind the dam, has dropped to its lowest since the lake filled in the1930s. If it keeps dropping, the dam, with a maximum capacity of 2,074 MW, could cease generation altogether — a first.

At a conference on reliability held Thursday by CAISO, the California Public Utilities Commission and the California Energy Commission (CEC), Mark Cook, manager of Hoover Dam with the U.S. Bureau of Reclamation, said the lake is now at 1,070 feet above sea level. The dam will stop generating power at 950 feet above sea level because its 17 turbines run too problematically at such low flow levels, he said.

"That's where we predict that everything is going to run rough enough that we're just not going to be able to produce any electricity," Cook said.

"All of our units have a rough zone in them," he said. "There's a band … in the middle of the operating region, where we don't like to operate very long because it's rough and vibrates and [it's] hard on the equipment."

With every foot that Lake Mead drops, the dam loses about 6 MW of generating capacity, he said.

Hoover Dam is generating about 1,500 MW, 25% less than capacity, Cook said.

"Hoover typically generates 4,500 GWh a year," he said. "In the last year it was down to more like 3,500 GWh, and so it's in the neighborhood of a 22% decrease [in] … energy output over the course of the year."

The drought in the Southwest, which some call a "megadrought," has been going on for years. California has been in a severe drought since last year, and normally wet Oregon has seen less precipitation, too. (See *Western 'Megadrought' Curtails Hydropower*.)

Hydropower generation in California, which normally meets about 14% of peak summer load, will drop by at least 1,000 MW — one-tenth of in-state production — starting this month due to low reservoir levels, said Angela Tanghetti, a CEC electric generation specialist. Generation could be further limited by wildfires in the rugged terrain where most dams operate, she said.

Hoover Dam is generating a fraction of its capacity because of a prolonged Western drought. | *Shutterstock*

Pacific Gas and Electric, which operates dozens of dams in the Sierra Nevada and foothills, expects to see a big dip in generation this summer. Its 16 large reservoirs account for 95% of its hydro generation, and the storage in those reservoirs is at its second lowest level in the past 40 years, said Eric Van Deuren, director of power generation engineering at PG&E.

The only dryer year was 2015, but only slightly, and 2021 could eclipse it, he said.

"As to the amount of water available in terms of the total generation, we are forecasting for our system …. approximately 45% of historic annual generation, which is pretty much the same number as the percent of precipitation … that we saw within the hydro area."

Snow water content in California peaked at 60% of normal in 2021 after a similarly dry winter last year, CAISO said in its annual summer resource assessment. The average water level in large reservoirs was 70% of normal earlier this year. (See *CAISO Could See More Outages this Summer*.)

FERC focused on the California hydropower crisis in its *Summer Energy Market and Reliability Assessment*. Snowpack, the state's main source of dry-season water, was critically low at 6% of normal levels May 11. Earlier-than-normal runoff will worsen the situation, FERC said. (See *FERC Summer Assessment Spotlights Western Drought Risks*.)

CAISO has said low in-state hydro could cause problems meeting peak demand this summer. In a meeting last month hosted by the U.S. Energy Association, CAISO CEO Elliot Mainzer said the hydropower situation adds volatility to resource planning and needs to be accounted for.

Whether drought conditions will abate or continue in future years is a big unknown, Mainzer said.

"The uncertainty … is absolutely something that we now need to bake into our planning," he said. ■

CAISO/West News

CAISO Declares Emergency as Fire Derates Major Tx Lines

Continued from page 1

500-kV lines that transport hydropower from Columbia River dams to population centers in California.

"Fire is on the AC Intertie right-of-way," Bonneville Power Administration spokesman Doug Johnson told *RTO Insider*.

The U.S. Forest Service called the fire's behavior "extreme."

"The fire will continue to move unchecked in all directions, with unstable air conditions and extremely dry fuels," it said. "Energy release components in fuels are at an all-time high."

The 500-kV PACI lines owned by BPA, PacifiCorp and Portland General Electric, partially originate at the BPA-operated John Day Dam on the Columbia River. From there they extend south, traveling through the fire zone, and connect to the Captain Jack and Malin substations just north of the California border. The lines then split off to feed power to customers of Pacific Gas and Electric, the Western Area Power Administration and multiple municipal utilities in Northern and Central California, including the Sacramento Municipal Utility District.

BPA derated the Oregon portion of the PACI from 4,450 MW to 428 MW by 7 p.m. Friday. Around the same time, the southbound segment of the Pacific DC Intertie (PDCI), which sends power from the Columbia River Basin to Southern California through Nevada, was derated to less than half its 3,100-MW capacity, while the northbound segment was shut down altogether. Co-owned by BPA and the Los Angeles Department of Water and Power, the PDCI cuts a similar course as the PACI through much of Oregon but lies farther to the east.

The unexpected limits on imported electricity forced CAISO to issue a grid warning and to later declare the emergency as solar power waned but demand remained high amid triple-digit temperatures in interior California.

Sacramento, for example, hit a high of 106 degrees shortly before 6 pm. Friday and 113 degrees after 5 p.m. Saturday, breaking the record of 112 on the same day in 2002.

CAISO said its initial warning indicated "that grid operators anticipate using electricity reserves [and activating] demand response programs to decrease overall demand."

"The ISO has been requesting additional energy from its neighbors and may call upon dispatching emergency demand response programs from 6 p.m. to 8 p.m., which is the peak and net peak," CAISO spokeswoman Vonette Fontaine said Friday. "That reduction in demand may be sufficient to avoid further emergency levels and avoid outages."

At 6:32 p.m., however, CAISO suddenly skipped a Stage 1 emergency and proceeded straight to Stage 2.

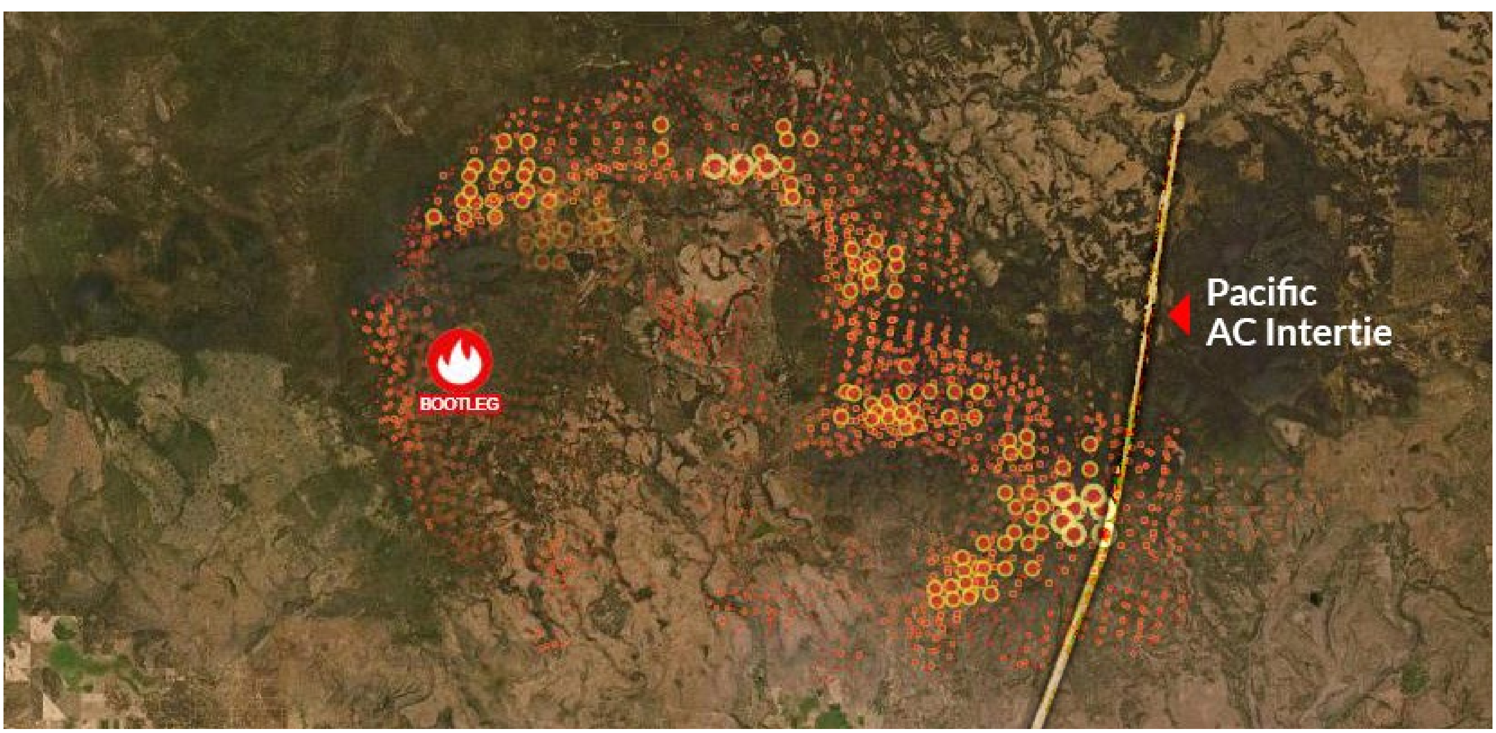
The emergency announcement stated that the ISO "has taken all mitigating actions and is no longer able to provide its expected energy requirements." CAISO avoided escalating to Stage 3, which could have led to rolling blackouts like those the ISO ordered last August amid a severe Western heat wave.

On Friday afternoon California Gov. Gavin Newsom signed an emergency proclamation to free up additional capacity, citing the loss of 4,000 MW of electricity supply.

At that time, the derate had not yet affected real-time operations of the Oregon portion of the line, BPA's Johnson said.

But the loss of supply appeared to be driving volatility in CAISO's real-time market, as prices at the Captain Jack and Malin nodes breached $1,000/MWh Friday evening.

At the same time, real-time prices at CAISO's NP-15 hub — the pricing point for Northern California — spiked to about $1,035/MWh, while the southern SP-15 hub topped $990/MWh. ■



Fire and smoke engulfed part of the Pacific AC Intertie in southern Oregon. | *NOAA Esri Earthstar Geographics*

ERCOT News

PUC Debates Answers to ERCOT's Reliability Issues

Work Session Yields Wealth of Information for New Regulators

By Tom Kleckner

The Texas Public Utility Commission's rookie electric utility regulators last week stood in front of the proverbial fire hose, wielded by ERCOT staff, market participants and the grid's Independent Market Monitor, as they try to get a grip on how best to respond to February's disastrous winter storm.

In what the PUC billed as the first of many general information work sessions "directly oriented" around Texas' recent legislative session, the commissioners heard from the market's stakeholders as they explored ERCOT's current ancillary services design and scarcity pricing mechanism, forward prices and their effect on investment decisions, and future technologies.

"This is a forum for a discussion of what's working, what's not working and how do we make it better," Chairman Peter Lake said in opening the conversation during the July 1 meeting. "No one should take anything said up here as being written in stone or some grand intention of future action."

But last week, Texas Gov. Greg Abbott gave the PUC marching orders when he *directed* it to "immediately" take action to increase generation capacity and ensure the grid's reliability.

Saying the PUC has the ability to "redesign segments of the market," he urged streamlining incentives to develop and maintain "adequate and reliable" sources of power. He suggested natural gas, coal and nuclear power, all of which were offline during the storm and contributed to ERCOT's inability to meet record demand.

At the same time, Abbott ordered the market to allocate reliability costs to generation resources that can't guarantee availability, a jab at wind and solar power. Similar language was struck from legislation that Texas lawmakers passed during their recent session.

Abbott also told the PUC to order ERCOT to establish a maintenance schedule for non-renewable generators and to accelerate development of transmission projects that increase connectivity between dispatchable generation plants and "areas of need."

The PUC has been completely revamped since the storm's freezing temperatures almost collapsed the grid. The commissioners at the time have all been replaced by industry outsiders Lake and Will McAdams. Lori Cobos, the newest commissioner, comes from the Office of Public Utility Counsel and sat on ERCOT's Board of Directors.

The commission will expand to five regulators before September, the result of one of the numerous bills recently passed by the Texas Legislature, which adjourned May 31. The centerpiece was *Senate Bill 3*, an omnibus bill that focused on weatherizing facilities and increasing administrative and civil penalties. (See *Texas Legislators Finish Work on Electricity Market — for Now*.)

Former PUC and FERC Chair Pat Wood pointed to SB3's Section 18 as the legislation's key language, calling it "the gem of Senate Bill 3." The section focuses on ERCOT's reliability responsibilities and directs the grid operator to determine and procure the ancillary or reliability services necessary during extreme weather conditions and during non-dispatchable power production.

Texas PUC Chair Peter Lake (center) sets the work session's stage for Commissioners Will McAdams and Lori Cobos. | *Texas Admin Monitor*

ERCOT News

Pat Wood shares his thoughts with the PUC. | *Texas Admin Monitor*

The bill's language defines non-dispatchable generation as any generation facility whose output "is controlled primarily by forces outside of human control" — in other words, renewable resources.

"Section 18 is the forward lane to how we make sure we fix the things that happened in February," Wood said. "But more importantly, this grid is shifting faster than any grid in the world. We have these resources shining and blowing on us. There's not a state like this. We've got to get this right."

Wood said that in the future, nuclear, wind and solar energy will be setting prices. "That other 20% is going to be really spiky and really pricey," he said, depending on how the grid's intermittent resources respond.

NRG Energy's Bill Barnes told the commissioners that competitive power markets have long struggled with addressing the "inherent conflict" between reliability and markets. Allowing the market to work "means you have to take risks," he said, none more so than relying on the energy-only market's high scarcity prices that drive investment cycles.

"One of the disadvantages is involuntary firm load shed may occur more often than found acceptable. The requirement of a workable energy-only market is customers, regulators and policymakers must be willing to tolerate price spikes and firm load shed," Barnes said, quoting a *2012 Brattle Group study* on ERCOT investment incentives and resource adequacy.

"February told us we don't," he said.

Barnes, NRG's chief Texas lobbyist, called for improving financial incentives for reliability and resource adequacy, "specifically, financial incentives for dispatchable resources."

He noted that ERCOT's most recent capacity, demand and reserves report indicates the grid operator has 65 GW of thermal capacity at its disposal. That means renewables are needed to meet demand when it exceeds 65 GW. That makes the management of variable resources' reliability key to resolving ERCOT's "root problem," Barnes said. "Products that help procure additional ancillary services when you have low wind and low solar ... are really what we think we need to supplement the existing market design."

Bill Barnes, NRG | *Texas Admin Monitor*

Barnes also called for additional changes to the market's operating reserve demand curve (ORDC), which he called the No. 1 tool for maintaining ERCOT's core market structure.

The ORDC was added to the market in 2014 following a report *filed* with the PUC by William Hogan, research director of Harvard University's electricity policy group. It creates a real-time price adder to reflect the value of available reserves. It has been tweaked in recent years as coal-fired generation was retired, shrinking ERCOT's reserve margin. (See *Texas PUC Responds to Shrinking Reserve Margin*.)

"We believe ORDC reform is so important," Barnes said. "What drives investment? The forward [price] curve. What sets the forward curve? Prices. What sets the prices? The ORDC."

IMM Director Carrie Bivens delivered a 101 presentation on ERCOT prices, beginning with the baseline energy price set by the marginal generating unit's marginal cost, usually set by a gas-fired resource. The ORDC and reliability deployment price adder are then added on, yielding the total system price.

"So, the feature of the market design is no one wants to offer more than the marginal price," Lake said.

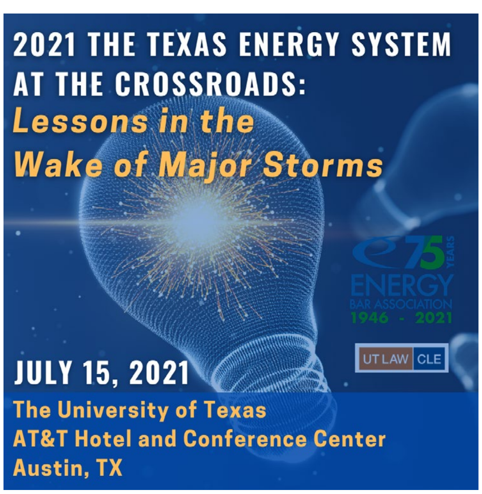
"If you're never in scarcity, then you don't need more generation. If you're in long-term scarcity conditions, that's a signal we need more generation," Bivens responded.

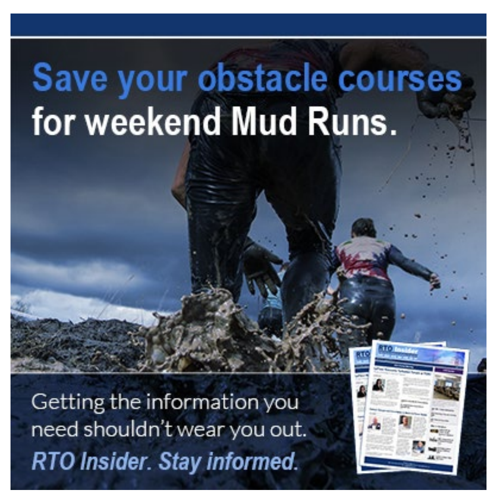
She explained that ERCOT's real-time prices are incenting fast-responding resources, such as gas turbines and energy storage. With the grid's current 15.7% reserve margin, the market is saying combined cycle units are not needed, Bivens said.

"The market is incenting investment," said Katie Coleman, who represents Texas Industrial Energy Consumers, referring to the mountain of wind and solar resources in ERCOT's interconnection queue. "It's not the type of investment you want, because we can't always rely on it."

Cobos noted that the PUC has only "certain knobs we can turn" to drive scarcity prices, a reference to the ORDC, price adders and the ancillary services market. "We'll have to work with what we have now."

"SB3 has some pretty big knobs in it," Lake said ■.





ISO-NE News

ISO-NE, NEPOOL Continue to Conceptualize Capacity Market Sans MOPR

By Jason York

ISO-NE and stakeholders kicked off a two-day NEPOOL Markets Committee meeting Wednesday with a session strictly devoted to discussing removing the minimum offer price rule (MOPR) from the RTO's capacity market.

The RTO *presented* its current thinking about the elimination of the MOPR and addressed stakeholders who sought clarity on two key issues discussed at the June 8-9 MC meeting: the rationale for proposing to eliminate the rule, and regional risk-related concerns with its removal. It aims to file a proposal to eliminate the MOPR with FERC in the first quarter of 2022 so that changes are in place for FCA 17, scheduled for February 2023.

Regarding the first issue, ISO-NE cited undercounting contributions to resource adequacy. High-cost resources developed to meet states' policy objectives do not clear the Forward Capacity Auction when the MOPR is applied, which is inefficient over time and results in excess regional investment, absent any reform, it said.

It is a different situation from when the MOPR was developed a decade ago, according to ISO-NE. The original rationale for the rule was its ability to deter the development of high-cost, uneconomic resources.

As for the risk-related worries, the RTO said there is uncertainty for future capacity prices and the potential for inefficient retirements.

Investors in new and existing resources making capital expenditures face greater risk over future capacity prices without the MOPR. ISO-NE said that Potomac Economics, its External Market Monitor, will address this issue at the next MC meeting in August.

Imprecise measurement of technologies' actual contributions to resource adequacy in the qualification processes and low-offer supplies without a MOPR could push premature retirement of resources whose flexibility, dependability and/or sustainability may be more valuable with high renewable penetration. ISO-NE said reliability risks are challenging to quantify. While addressable with new energy and ancillary service market designs, the RTO's present concerns remain as inefficient retirements are irreversible.

The RTO is evaluating using the FCA market-clearing engine to simulate potential clearing impacts of the MOPR's elimination and expects to have more specifics for stakeholder input in August to provide preliminary results for review in September.

Stakeholders Offer Ideas

Calpine and Vistra offered their initial conceptual approaches dealing with the removal of the MOPR.

Brett Kruse of Calpine *discussed* changing the market rule for capacity supply obligations (CSOs) by reducing capacity resources' combined notification, start-up and minimum run and down times to 24 hours from 72 hours. Kruse said that regardless of what happens with the MOPR, ISO-NE should revise the rules for CSOs to reflect system needs better.

Kruse said CSOs are a tariff provision from the original Forward Capacity Market settlement in 2005 in which ISO-NE wanted to ensure that several limited generation resources exited the market. However, the requirement is administrative, and there was no analysis used to support it, he said. In 2005, the RTO wanted more flexible resources, because they are inherently more valuable. The need for flexible resources is more pronounced now than in 2005, and Kruse said that 24 hours is better for system reliability than 72 hours.

He added that the EMM reinforces a similar resource reliability assessment of the resources that may be affected by this potential rule change in its 2020 state of the market *report*.

Vistra's Andrew Weinstein *said* that the capacity market must better accommodate state policy goals. While narrowing the MOPR is inevitable, durable capacity market design requires buyer- and seller-side market power mitigation. Weinstein said that eliminating the MOPR without replacement buyer-side market power mitigation is risky given FERC and court precedent.

Weinstein said that a Competitive Auctions with Sponsored Policy Resources (CASPR) transition that substantially accommodates state-subsidized resources while preserving investor confidence and avoiding cost shifts could be appealing as a permanent solution. He added that tying renewable technology resource exemption amounts to CASPR's success will ensure the design is focused on material participation in the FCA by subsidized resources.

It would also give ISO-NE time to develop a durable market design, including effective load-carrying capability, a carbon solution and the required buyer-side mitigation rules that would need to be much narrower and more targeted than existing ones. ■

| *Shutterstock*

ISO-NE Presents Revised Design for Order 2222 Compliance

By Jason York

ISO-NE's revised *proposal* for FERC Order 2222 compliance was the singular focus for the NEPOOL Markets Committee on Thursday as it wrapped up a two-day meeting.

The RTO presented changes to energy and ancillary services (EAS) market participation, metering and telemetry requirements, distributed energy resource aggregation (DERA) registration coordination and Forward Capacity Market (FCM) participation.

Throughout its presentation, ISO-NE also responded to stakeholders who presented at the MC meeting in June.

Changes Outlined

Regarding EAS markets participation, the RTO added a demand response DERA model and expanded the existing participation models to allow for aggregations. The initial proposal did not allow demand response DERs to aggregate with other types of DERs.

ISO-NE said the demand response DERA model might include demand reduction, energy injection and energy withdrawal capabilities. The model also leverages most of the market features from the existing DR resource model to provide compensation for demand reductions based on Order 745 requirements.

The grid operator's updated proposal now aligns the metering and telemetry requirements for aggregations with existing requirements for non-aggregated assets. This model ensures metering equivalence between aggregated and non-aggregated resources for market products being bought and sold, real-time situational awareness, accuracy, precision and latency. In addition, the utilization of existing meter data collection systems will also facilitate cost-efficient implementation.

Response to AEE

At the June MC meeting, Advanced Energy Economics *said* device-level metering is necessary for Order 2222 compliance and suggested that third-party meter readers be included in the design. AEE also noted that submeters are allowed for passive demand resources and that third parties are used to report revenue quality metering (RQM) and telemetry for active demand resources.

Data used for settling passive or active demand resources do not impact energy market settlement and are not subject to reporting by the meter readers.

Passive demand resources, including energy efficiency resources, and some behind-the-meter distributed generation, also do not participate in the energy market. Active demand resources, like DR resources, are economically dispatched, but any payment for demand reductions is funded through mechanisms outside of the market. The metered load reported for settlement includes any demand reductions achieved by demand resources, so the measurement of and payment for demand reductions must occur outside the market.

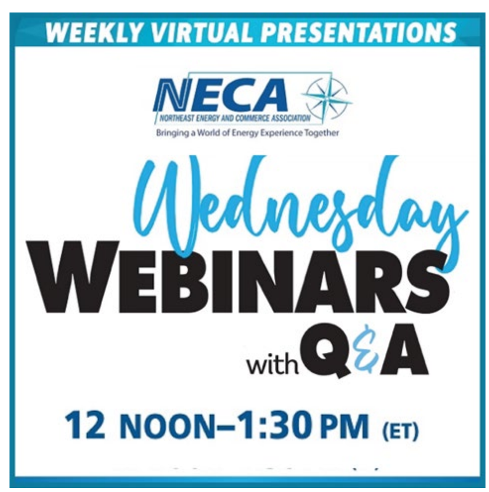
In New England, Participating Transmission Owners (PTOs) are responsible for reading the meters for energy market assets, based on the Transmission Owners Agreement and Manual M-28. For that reason, ISO-NE said it is not authorized to conduct meter reader functions or permit the use of a third-party meter reader, which would have to be approved by the relevant PTO. PTOs are responsible for providing RQM for generation, tie lines and load. Cost recovery of metering infrastructure is subject to state review and approval.

Because of these differences across utility territories and jurisdictional issues, the RTO said it does not find it appropriate to mandate a specific metering approach that requires reconstitution or parallel metering of behind-the-meter DERs.

Next Steps

The MC and other technical committees will continue discussion of the RTO's proposal in August. In September, ISO-NE will present the final draft of its proposal and initial tariff redlines. Stakeholders who want to pursue alternative approaches should indicate their intentions to present at the October technical committee meetings.

Any remaining design refinements to the RTO's proposal, continued review of tariff redlines and potential stakeholder amendments will occur in November. NEPOOL's technical committees will hold votes on ISO-NE's proposal and stakeholder alternatives at the technical committees in December, and the Participants Committee is slated to vote in January ahead of the Feb. 2, 2022, filing deadline with FERC ■.



MISO News

Discord Persists over MISO Seasonal Capacity Accreditation

By Amanda Durish Cook

The seasonal accreditation of MISO capacity resources continues to be a point of contention among the RTO, its Market Monitor and the stakeholder community.

MISO restored some of the bite to its accreditation proposal when it announced Wednesday that the riskiest 3% of hours will be assigned an 80% weight in accreditation, while the non-risky hours will have the remaining 20% weight. MISO's Independent Market Monitor recently warned board members that MISO's leniency in the accreditation proposal would do nothing to strengthen resource availability.

MISO last month softened its accreditation proposal to include availability during non-risky hours in addition to the tightest 3% of hours in a year as the basis for accreditation. (See *MISO Softens Capacity Accreditation Proposal*.) The RTO wants to file in September to introduce a seasonal capacity accreditation based on generators' availability over the last three years. The seasonal accreditation will be used in a four-season capacity auction and corresponding reserve margin targets. The RTO plans to begin holding four independent seasonal auctions by the 2023/24 planning year.

"We're very motivated for a September filing," Executive Director of Market Strategy and Design Scott Wright told stakeholders during a Resource Adequacy Subcommittee teleconference on July 7. However, MISO agreed to a stakeholder request to collect a round of stakeholder feedback on the 80/20 weighting.

Noblesville Station in Hamilton County, Indiana | *Duke Energy*

MISO selected the riskiest 3% of hours for the Midwest and South regions separately. Included were hours that contained maximum generation events and warnings and other hours across seasons with tight operating conditions. The RTO excluded all hours that contained a more than 25% supply margin. The 25% threshold means some seasonal accreditation will be based on fewer than the 65 hours that make up 3% of a season.

"Stakeholders need to be personalizing the impact on their portfolios as a result of the changes," Wright said.

Monitor has Harsh Words

During a July 8 Market Subcommittee meeting, Monitor chief David Patton said he will likely register a protest with FERC over MISO's accreditation filing, which he said would award a bloated capacity credit to inflexible and slow-moving resources.

"It's important to provide adequate credit to resources that can respond with short lead times or are always on," he said. "It's one of the reasons we're unhappy with MISO's filing."

Patton said generators with up to two-hour lead times are "probably close enough" to the response time of an online unit. He also proposed a sliding scale for the capacity credits of units with lead times up to 12 hours.

The Monitor said MISO's current proposal is risking creating a system that doesn't reward the most efficient contributors to reliability.

"It's such an important proposal that we ought to be doing the right thing, not the popular things," he said. "I'm concerned that stakeholders are worried that this accreditation proposal is going to harm them. … If you own gas resources or pumped storage or anything that's flexible, you should really be advocating for a more principled accreditation."

Patton added that MISO's proposed suite of resource adequacy solutions is "a poor way to deal with the fact" that MISO's Planning Resource Auction provides paltry compensation for capacity. He repeated his longstanding recommendation that the RTO use a sloped demand curve instead of a vertical demand curve in the PRA.

MISO Analysis Shows Less Capacity, Lower Requirements

The grid operator said an analysis of the new accreditation method showed a system-wide reduction in accredited capacity, which is offset by lower seasonal reserve margin requirements. It said nearly all local resource zones should have adequate capacity to cover seasonal clearing requirements. Senior Manager of Resource Adequacy Coordination Lynn Hecker said the only exception is wintertime in Mississippi's Zone 10, which stands to face a smaller seasonal capacity supply and lower capacity import limits. MISO said Zone 10 could find itself about 700 MW short of its winter requirement.

Mississippi Public Service Commission counsel David Carr called for a special meeting between MISO and the PSC to discuss the RTO's transfer limit analysis using the seasonal values and the potential shortfall it found. Hecker said MISO could schedule such a meeting.

He said the RTO found that thermal capacity resources will see the biggest changes in wintertime under the seasonally adjusted accreditation. It also found that about 35% of thermal capacity units in the winter experience an increase in accreditation, while 65% have their accreditation decreased.

MISO is still deciding whether it will still use its effective load carrying capability (ELCC) values for intermittent generation in a seasonal capacity paradigm. Wright said ELCC already gets at some of what the grid operator is trying to accomplish for thermal generation in its seasonal capacity filing.

The RTO also took stakeholders by surprise by including September back in its fall definition, rather than summer. Stakeholders have said warmer Septembers coupled with fall maintenance outages are a breeding ground for maximum generation emergencies.

Hecker said MISO may reevaluate the merits of a September in the summertime categorization.

Stakeholders also asked how the RTO will split up calls for load-modifying resources by season. Beginning in the 2022/23 planning year, demand response resources receive a 100% credit if they can be available within six hours or less to 10 calls or more in a planning year, while resources that can respond to five to nine calls receive an 80% accreditation. Until then, LMRs must respond the requisite five times per year.

Hecker said MISO is considering dividing a minimum of "10 or so" calls for LMRs by season. ■

MISO News

MISO Market Subcommittee Briefs

MISO Defends June Emergency Declaration

Stakeholders last week questioned MISO's decision to call an emergency to access load modifying resources on June 10 as it contended with above average temperatures and forced outages.

A premature northern heatwave during the end of spring generator maintenance season set off a brief maximum generation emergency in MISO's North and Central regions. MISO ultimately asked for about 2.5 GW in load reduction and received about 5 GW more than requested. (See *MISO Leadership Says Tx Expansion, Market Redefinition 'not Optional'*.)

Jason Howard, MISO manager of day-ahead commitments, said the RTO managed the emergency reliably. He said it began taking steps June 7 to prepare for tight operating conditions.

"One of the attributing factors is 32 GW in outages, 22 GW of which was unplanned and derates," Howard said at a Market Subcommittee meeting July 8. "This is an unexpected number of outages."

Howard said some northern points of the footprint experienced temperatures that were 15 degrees above average. He also said MISO's data showed that imports would be sparse during the day.

MISO Senior Director of Operations Planning J.T. Smith said MISO operators realized by 10 a.m. that units' emergency outputs wouldn't cover a projected shortfall and that LMRs were needed.

Several stakeholders said they weren't convinced that MISO exhausted the full ability of its non-emergency units and imports before turning to emergency-only resources.

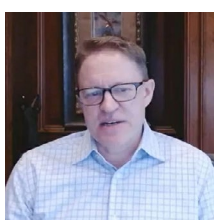
Some questioned the two-hour notification time, which was enshrined in the MISO tariff last year in response to stakeholder calls for more warning ahead of emergencies. Under the new rule, MISO *must* declare an emergency "at least two hours prior to the anticipated emergency event."

Smith said MISO couldn't bank on an increasing supply of non-firm imports at the time. He also noted that MISO's resource adequacy construct means that LMRs exist to cover summer peak load.


MISO control room | *MISO*

"We were really right on the cusp. … We have more than 10 GW of capacity sitting behind a Max Gen step 2a call," Smith said.

"The reason why we call ahead of time is we will exhaust our short-lead time LMRs very quickly, and we'll never use the two, four, six-hour [lead time] LMRs," MISO Executive Director of Market Operations Shawn McFarlane said.


David Patton | *FERC*

MISO Independent Market Monitor David Patton said it's not surprising that the unseasonably hot weather and outages sent MISO into a tailspin.

Patton said MISO should use more realistic assumptions when calculating reserve margins.

"We keep reporting margins that seem high and seem to cover everything," he said.

But Patton said MISO doesn't fully account for unscheduled summer outages and derates.

"The reality is we have outages and derates that average 10 GW," he said.

MISO's current 19.3% reserve margin is above 2021's 18.3% requirement, Patton said, but likely forced outages reduce the margin to 17.1%. If MISO modeled a more realistic scenario that included expected outages and derates, a 2,300-MW transfer limit between MISO South and Midwest and, accounted for its LMRs with long lead times, the expected reserve would fall to 10 to 13%, he said.

But that still leaves abnormally hot conditions unaccounted for, Patton said. If MISO assumed high demand from a sweltering day, the margin could drop to 1% or less.

MISO's frequent maximum generation events are "really not as big a mystery as it appears," Patton said.

However, Patton said MISO's saving grace is non-firm imports during times of need from its neighbors.

"It's why we probably don't need to carry as much capacity as other areas," he said.

Howard agreed that MISO has a high dependence on imports and said unusual weather patterns can throw imports into doubt.

Market User Interface Launch Delayed

MISO is delaying the launch of its new market user interface, part of the RTO's market plat-

MISO News

form replacement.

MISO IT Senior Director Curtis Reister said the notifications feature of the new interface has problems that the vendor is working on. He said MISO will delay the planned July 6 parallel operations of both the old and new interfaces for an unspecified amount of time.

"We don't have a new [start] date. We want to give ourselves time to apply this patch," Reister told stakeholders. He said MISO will use the time to ensure the solution works before opening the interface to stakeholders.

He said MISO still plans four months of parallel operations and will delay the old user interface's retirement date. Market participants use the market user interface to submit bids and offers in the MISO markets.

The new interface test environment has been open for testing by market participants since April. Parallel operations of the new and old interfaces were originally expected to take place July through October.

Reister said MISO will know more about the length of the delay in mid-July.

The new market platform will *accommodate* 30-minute reserves and energy storage participation and provide better modeling for combined cycle units. MISO has put those products on hold because its current monolithic platform isn't sophisticated enough for them.

Monitor Says Congestion Worsening

The Monitor also appeared before the Market Subcommittee to again warn of MISO's increasing congestion costs.

"There's a trend in MISO of increasing congesting that we don't think is going to slow down," Patton said. The Monitor told MISO's Board of Directors in June that the grid operator needs to address increasingly expensive congestion. (See *MISO Monitor Warns of Ramping Needs, Tx Congestion*.)

Patton told stakeholders that congestion is a major "cost generator" in MISO, with congestion costs doubling from last spring to Spring 2021.

MISO is on track to incur $2 billion to $2.5 billion worth of congestion costs this year, he said.

"That's a level of congestion we haven't seen on an annual basis over the last three years," he said.

He added that Spring 2021's average real-time congestion was the highest it's been since 2014, owing to a 58% year-over-year increase in natural gas prices, higher market-to-market congestion with SPP and PJM, and growing wind output.

"As wind generation ramped in the fall of 2020 and the spring of 2021, we saw huge amounts of congestion on constraints … in the Midwest region," Patton said.

The Monitor said in some intervals, wind generation can serve up to 40% of the RTO's Midwest load. ■

—Amanda Durish Cook

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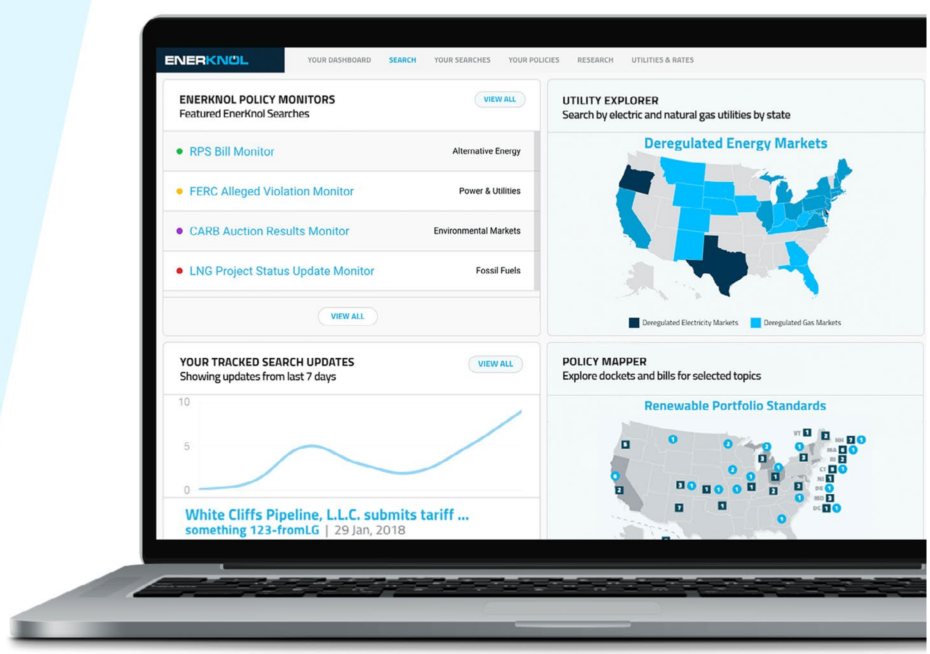

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NYISO News

NY Utilities, ESCOs Offer Tweaks to CCA Rules

By Michael Kuser

Investor-owned utilities and energy service companies (ESCOs) in New York picked apart state recommendations on community choice aggregation (CCA) made in an April white paper, supporting some and rejecting others (*14-M-0224*).

The Department of Public Service staff *paper* made recommendations to resolve program challenges, remove barriers to data access and better incorporate distributed energy resources into CCA programs.

The Municipal Electric and Gas Alliance (*MEGA*), an ESCO serving upstate New York, *said* it supports program standardization and uniformity in elements of the CCA program rates but disapproves of the recommendation to adopt a 5% cap on commodity product offerings.

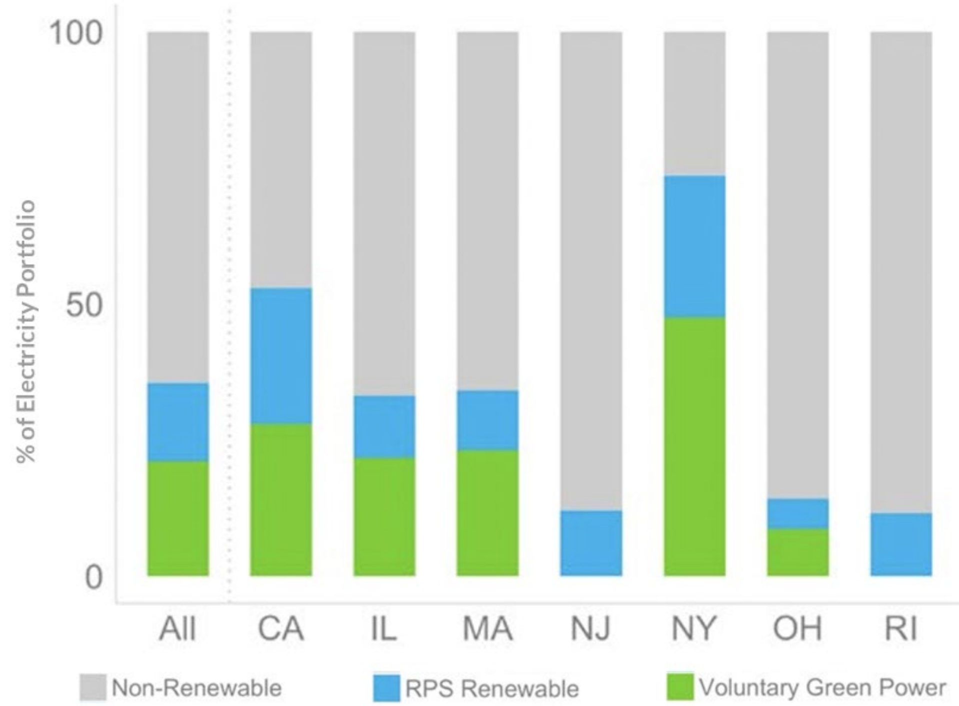
"The fundamental calculation of the 'price to compare' is flawed, [and] to use a baseless price construct and impose a 5% cap is nonsensical. More importantly, it is disconcerting that staff is considering imposing an artificial limit to a free and competitive supply market," MEGA said.

DPS staff recommendations include standardizing CCA program filing requirements; streamlining the filing process; modifying existing requirements; and adopting additional requirements.

NRG Energy *said* it generally agrees with the department's proposal to develop a uniform filing structure, but not with the recommendation that all program participants be enrolled in the same rate, regardless of when they join the CCA, unless they voluntarily choose a different option.

"NRG prefers the ability to enroll new participants on a different rate due to seasonality and price risk ... [and] does not necessarily agree with the proposal surrounding the price to compare," the company said.

"First, the price to compare in New York is not a fair apple-to-apples comparison. Utilities adjust and true up their rates after the fact, making it impossible for ESCOs to compete with the rate," NRG said. "As a result, including the price to compare on a customer's bill will be misleading and not an accurate summation of the value they are receiving from participating in the CCA program."



Voluntary green power shares of CCA electricity portfolios by state in 2019 | *NREL*

Make-work Complaints

The state's IOUs *said* they support standardizing guidelines, processes and procedures for CCA programs; "however, some staff recommendations are infeasible and cannot be cost-effectively implemented at this time. Others require additional collaboration to develop necessary program rules and details, especially as it relates to integrating community distributed generation (CDG) on an opt-out basis."

The IOUs recommended, to ensure consistency, using the quarterly 12-month trailing average price to define the price to compare for the CCA market. But they requested further discussion among stakeholders regarding the public-facing display of such information "to determine whether using the current 12-month trailing prices is sufficient, how to best present residential and nonresidential service classification information most clearly, and what effect displaying the price has on the different programs."

The utilities also opposed the recommendation that during a CCA program opt-out period, the utility be required to maintain a record of every customer that contacts them to opt out or to have an ESCO enrollment block placed on their account for the purpose of CCA program opt-out.

"There are little to no benefits in requiring" utilities to track customers in such a way, and this additional tracking and reporting is "needless" because enrollment in the CCA will not happen if the customer has requested a block on their account during the opt-out period, the IOUs said.

Additionally, the utilities urged the Public Service Commission to address conceptual design elements before either extending the ability to combine opt-out CDG with CCA or allowing opt-out CDG-only programs.

The IOUs said design elements that need to be considered include compensation that reflects reduced developer costs of the opt-out CDG model; potential inequities among municipalities; utility data considerations; customer protections; and implementation and administration changes for opt-out CDG.

MEGA said that "pairing CCA programs with opt-out CDG savings provides a powerful tool given the challenges with procuring affordable 100% green electric supply for CCA communities. By pairing the programs, communities that are hesitant to potentially increase resident electric bills with 100% green supply can access a guaranteed savings program through opt-out CDG."

If New York state is invested in incentivizing and growing CCA programs, the two programs should remain paired, MEGA said, noting it "does not support standalone opt-out CDG but recommends that these programs operate in tandem to enable greater renewables access and affordability."

The IOUs cautioned that creating a set of blanket requirements for as yet undefined new offerings may not be achievable considering the potential number of permutations that could arise, instead recommending the commission establish "an ongoing framework under which it will consider authorization of new CCA programmatic offerings."

Consumer Protections

NRG also urged the commission to make further improvements to the filing process. The system does not currently work with many of the newer browsers that corporations are using, and older browsers do not always work with corporate firewalls and other protections.

The company made specific requests regarding both the aggregated dataset and the customer-specific contact information set.

"Sometimes the rules may seem appropriate on paper; however, when actually implementing the program, they are not practical in nature," NRG said.

The aggregated dataset should provide the customer's bill cycle and period codes, rate class and NYISO ICAP tags and zones, as these fields are necessary for ESCOs to accurately price customers and prepare a bid. The bill cycle and period codes are the most important pieces of information for timing purposes, NRG said.

In addition, NRG said it does not believe that municipalities are authorized to impose gross receipts tax (GRT) on customers taking service under CCA programs.

"Any suggestion that NRG and other ESCOs should increase their charges to CCA customers and then make payments to such municipalities 'in lieu of' GRT would violate Rule 28 of the commission's CCA rules, which expressly provides that 'municipalities may not collect funds from customer payments to cover lost sales tax revenues,'" NRG said.

The Coalition for Community Solar Access (CCSA) *said* it supports the commission's requirements to always provide savings, to not include a credit check, and to ensure necessary outreach and education.

Regarding an April *petition* from software company Ampion for PSC approval of a program similar to a traditional CCA that supplies only a CDG product — one not integrated with other CCA products — the solar coalition encouraged the commission "to review the petition from the same lens it has reviewed this matter: ensuring the customer choice, customer engagement, consumer protection and customer benefits are at the center of all consideration." ■

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Long-delayed Solar Project Breaks Ground in Central Wash.

NYISO News

BOEM Reviews Empire Wind COP Environmental Impact

Record of Decision Not Due Until 2023

By Michael Kuser

Labor unions, environmentalists, state residents and energy professionals told federal officials Thursday they largely support the 2-GW Empire Wind project in the New York Bight. A clam fishery representative, however, accused the developer and state and federal governments of being insensitive to their special needs.

The Bureau of Ocean Energy Management (BOEM) on July 8 held the second of three public hearings, as the agency begins to review the project's environmental impact with data from the developer's construction and operations plan (COP). BOEM has scheduled the third *hearing* on July 13 at 1 p.m. for the project of Norwegian state-owned energy company Equinor Wind US.

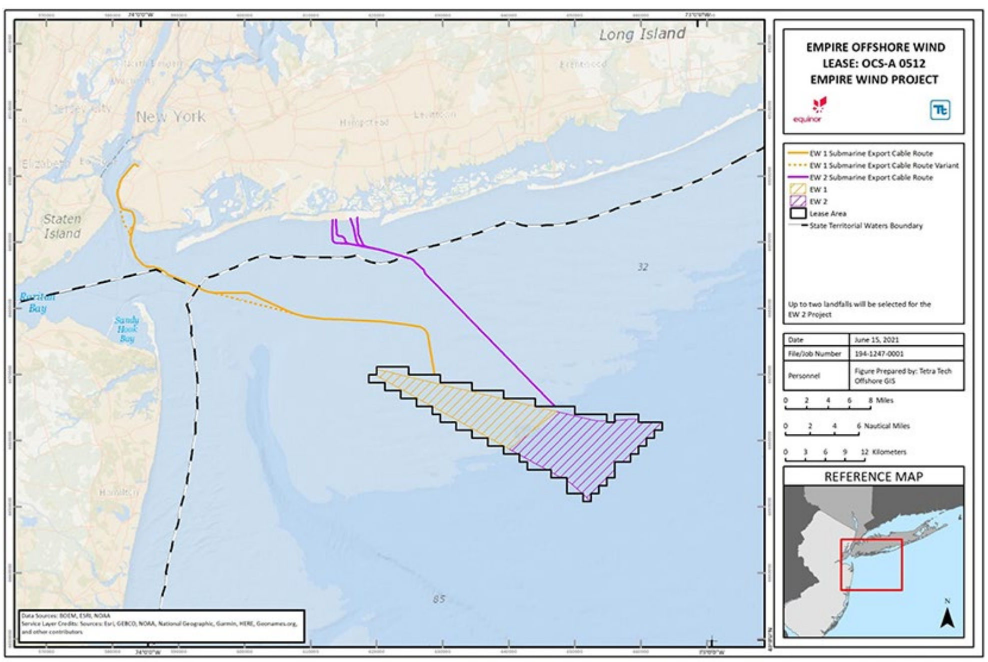
"As we emerge from the COVID crisis ... the economy, environmental justice and climate change are interwoven with offshore wind development," said Mariah Dignan, the Long Island organizer for Climate Jobs New York (CJNY), a coalition of labor unions representing 2.6 million working New Yorkers. "We have a once-in-a-generation opportunity to put ourselves on the path to a low-carbon future, while creating new quality careers that provide family-sustaining wages and benefits for communities across the nation."

Laura Morales, Empire Wind | *BOEM*

Empire Wind consists of two separate projects, 810-MW Empire Wind 1 and 1,260-MW Empire Wind 2, awarded under different state solicitations and which will be electrically isolated and independent from each other, according to Laura Morales, Empire Wind's environmental permit manager. The facilities will connect via offshore substations to separate points of interconnection onshore, she said.

Michelle Morin, BOEM | *BOEM*

BOEM will issue a draft environmental impact statement next summer and expects to issue a final decision of record in mid-2023, said Michelle Morin, chief of BOEM's environmental branch for renewable energy. Comments for this round of review should be submitted no later than July 26.



Empire Wind 1 and Empire Wind 2 will be electrically isolated and independent from each other, connecting via offshore substations to separate points of interconnection onshore. | *Tetra Tech*

Equinor plans to bring the Empire Wind project into service by 2025.

Clams and Piles

The clam industry would be negatively affected by installation of thousands of wind turbines in the mid-Atlantic and New England, said David Wallace, who spoke on behalf of the North Atlantic Clam Association.

The clam industry is unique in that it's a directed fishery "that can only exist with being able to drive piles deep into the substrates and soft bottom without a lot of heavy rocks."

OSW technology has developed since Equinor first acquired the lease in December 2016 for $42.5 million. The developer's new COP proposes reducing the number of turbine foundations from 240 to 176, spacing turbines at least 0.7 nautical miles apart, and laying out the array in a Southwest-Northeast orientation that considers the dominant net fishing activities in the lease area, Morales said.

The Army Corps of Engineers insists on burying the export cables at least 15 feet below the seabed, she added.

Clammers have "proposed on numerous occasions to separate those turbines two nautical miles apart in straight lines, so that we could operate within those turbine arrays," Wallace said "However, we have found that none of the developers are interested or willing to spread their turbines out ... we are not interested in being collateral damage to very high rates of electric utilities."

Stakeholders at a public hearing on the 800-MW Vineyard Wind project last July urged BOEM to approve the 1-nautical-mile turbine spacing advocated by developers and recommended by the U.S. Coast Guard, which the agency did earlier this year. (See *Developers Seek 1-Mile Spacing for Vineyard Wind*.)

The Empire Wind 1 export cable will make landfall in Brooklyn at the South Brooklyn Marine Terminal. After the energy is converted to AC, it will run through a cable underground to the point of interconnection, which is the Gowanus Substation, across second Avenue, Morales said.

For Empire Wind 2, the developer is looking at landfall alternatives to host two separate export cables to the point of interconnection at Oceanside, on the National Grid property in

NYISO News

Island Park.

Tom Barracca, a career energy professional based in East Meadow, New York, said he was involved as a program manager in the 2002 Long Island Power Authority (LIPA) offshore wind study co-sponsored by the New York State Research and Development Authority.

"Although the offshore wind economics and technology wasn't there 20 years ago, it is today, and Equinor and the Empire Wind team have done a tremendous job in planning these projects and making the necessary studies and due diligence," Barracca said.

Supportive of the plan to deliver 2,000 MW of clean power into Consolidated Edison (NYSE: ED) territory, Barracca said the plans to feed into the LIPA load pocket in southwest Nassau County are especially useful for the region.

"As many people might know, there's an aging power plant [the 610-MW E.F. Barrett Power Station] in Island Park that's been upgraded many times and is still operating," Barracca said. "National Grid is committed to make the best use of that, but quite frankly, it's time for renewable power to be brought into Long Island and into New York City, and Empire's plan to inject clean power into those load pockets is perfect timing."

Urgent, Scenic Views

BOEM heard from members of the public about urgent action on climate change and the viewshed off New York's coast.

"[A]fter yet another record-breaking and deadly month of heat waves, it seems to me that our absolute No. 1 priority for all energy projects should be simply, 'Do they help us get to a carbon-neutral future?'" said Tara Noble, a lifelong New York resident.

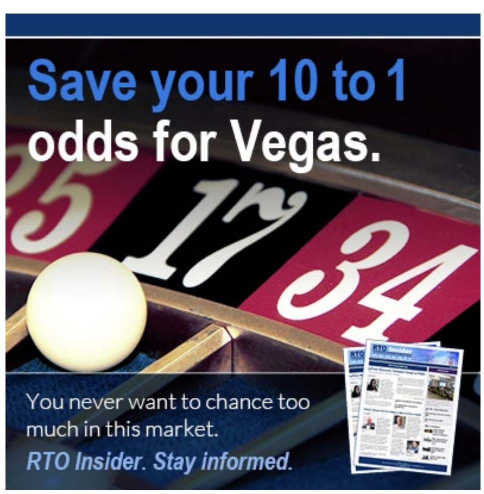
If the answer is yes, she added, "we are obligated to pursue them without delay."

The visual impact of the turbines is of deep concern to artist and Long Beach, N.Y., resident Michael Halpern.

Seeing wind turbines on the horizon would disturb him emotionally, aesthetically and spiritually, interfering with his visits to his late mother's memorial bench on Riverside Boulevard, Halpern said.

The wind turbines, he said, would take "the magic of going to the beach away," and when he paints, he added, "I'm not going to be looking out at eternity and God's presence, I'm instead going to be looking at an industrial wasteland."

While "not totally against clean energy," Halpern said, he supports building solar panels and "wind turbines in specific places, but not here off the coast of Long Beach and New York City." ■



NYISO Q1 Prices Return to Pre-Covid Levels

By Michael Kuser

NYISO energy markets performed competitively in the first quarter of 2021, and energy prices rose 40% to 143%, primarily because of higher gas prices, the ISO's Market Monitor reported.

All-in prices ranged from $22 to $69/MWh, up from the very low values observed in the first quarter of 2020, but "consistent with prices we saw in quarters before last year," Market Monitor Pallas LeeVanSchaick of Potomac Economics told the Installed Capacity/Market Issues Working Group Wednesday in presenting the State of the Market *report* for the first quarter.

Congestion increased because of larger gas price differences between regions and lengthy transmission outages along the Central-East interface and into Long Island.

"We saw capacity prices rose significantly in New York City as a result of the higher locational capacity requirement (LCR)," LeeVanSchaick said. Prices also increased outside the city "but were still quite low."

Oil-fired generation rose notably from late January to mid-February as gas prices in East NY rose to the oil price level because of cold weather conditions. However, the weather was not severe enough to put significant strain on the gas supply and oil inventories.

Spot capacity prices averaged $0.61/kW-month in Long Island, the G-J Locality and Rest of State, and $8.68/kW-month in New York City in the quarter.

The rest-of-state prices rose sharply in percentage terms, but prices were very low in 2020-Q1. The price rose primarily because of supply offer changes. The spot price rose substantially from $0.06/kW-month in January to $0.89/kW-month in February and March, with unsold capacity rising to ~580 MW.

Reliability commitments rose modestly in NYC because of higher load and more transmission outages, leading to higher bid production cost guarantee (BPCG) uplift. But LeeVanSchaick said NYISO and Con Edison have made procedural changes for N-1-1-0 requirements in the city in recent years, which have improved the efficiency of these commitments and reduced uplift.

"They have reduced the incidence of commitments that were not necessary for reliability," he said. "For example, previously, we had seen instances where they committed a unit for 24 hours when it was only needed for two or three hours."

Emission Signals

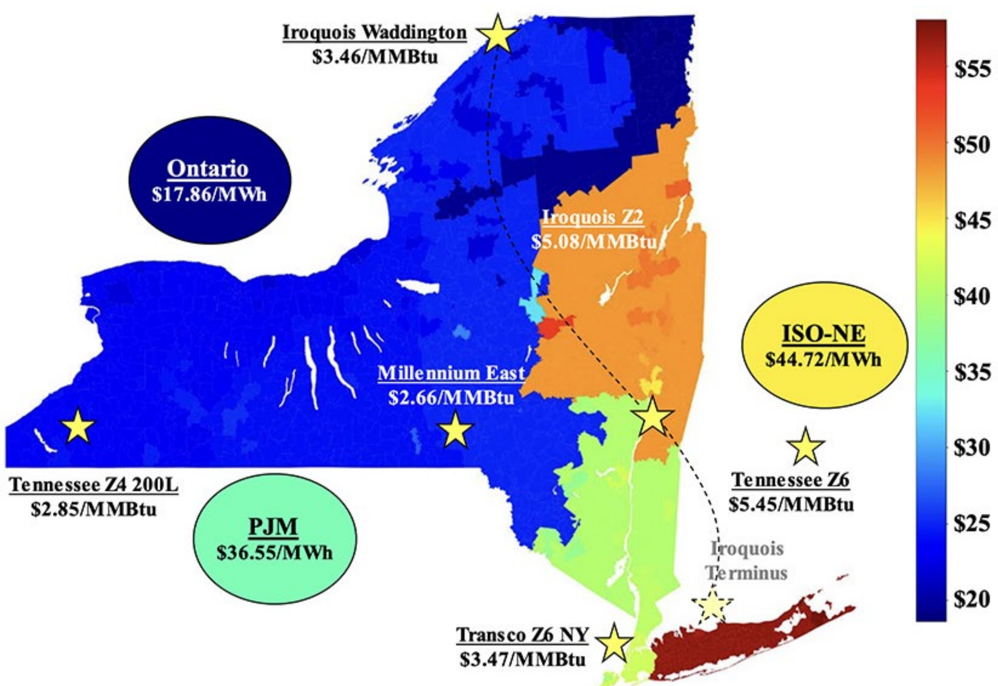
Nuclear and hydro generation fell by an average of 1 GW collectively from a year ago, reflecting the retirement of Indian Point 2 and more frequent freezing conditions. Consequently, gas-fired generation rose by more than 7% despite higher natural gas prices.

Gas-fired steam turbine generation rose by 660 MW on average. Most of the increase occurred on Long Island, where steam turbines were used more often during lengthy transmission outages to serve load, satisfy reserve needs, and support contractual requirements to export to New York City.

However, gas-fired combined cycle generation fell by 250 MW in the Hudson Valley. Increased gas pipeline constraints limited production from gas-fired units in the region during many cold days in the quarter.

Oil-fired generation on Long Island rose significantly on many days in January and February as cold weather drove gas prices to the level of oil prices.

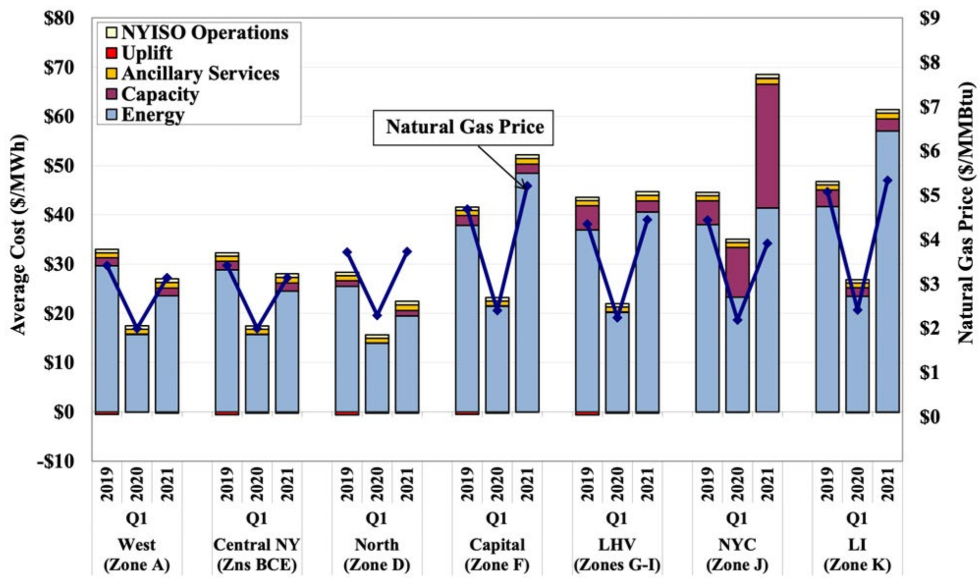
These changes led to increased CO_2, SO_2 and NOx emissions from the same period a year ago, despite the retirement of coal generation in 2020. Long Island accounted for most of the increases in emissions, which are an anomaly



NYISO system price diagram | *Potomac Economics*

NYISO News

from long-term trends and show how difficult it will be going forward to achieve incremental reductions in emissions from power generation, LeeVanSchaick said.



The graph summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes components of energy, capacity, uplift and ancillary services. | *Potomac Economics*

Congestion Patterns

Day-ahead congestion revenues totaled $179 million, up 222% from the first quarter of 2020. The increase was driven by higher gas prices, especially in February, and lengthy transmission outages along the Central-East interface and into Long Island.

The Central-East interface accounted for the largest share (77%) of day-ahead congestion revenues in the first quarter of 2021.

Long Island accounted for 7% of congestion, primarily on 345-kV paths from upstate to Long Island because of lengthy transmission outages. NYC congestion was relatively low, accounting for only 5% of total congestion in the first quarter of 2021.

NYC congestion has been relatively low in recent years since generation there has become more economic because of lower Transco Zone 6 NY gas prices relative to gas prices in other parts of East NY.

NYISO has greatly reduced the use of out-of-market (OOM) actions to manage low-voltage transmission constraints in the past two years by modeling most 115-kV constraints in the day-ahead and real-time market models, he said. OOM actions to manage lower-voltage network congestion were most frequent in the North Zone (13 days) and Long Island (10 days) this quarter.

Oil-fired peakers were dispatched out-of-market on eight days for 69-kV constraints in Long Island. NYISO began to represent certain 69-kV constraints on Long Island in the market models in mid-April 2021, which should improve the efficiency of congestion management and investment incentives.

Reliability commitments in NYC accounted for roughly 84% of all reliability commitments in the quarter and rose 19% from a year ago. The increase reflected higher load levels and more transmission outages in the 345-kV system and around the Freshkills load pocket.

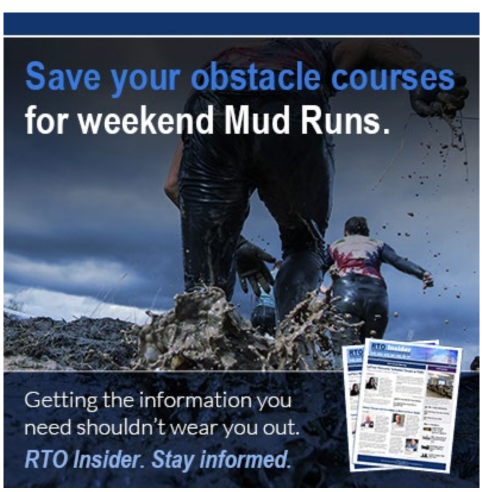
Nonetheless, NYISO and Con Ed have implemented several procedural changes for N-1-1-0 reliability commitment in NYC load pockets in recent years.

For instance, since January 2021, NYC load pocket requirements assume the use of 300-hour ratings rather than normal transfer limits after the second contingency, which have improved the efficiency of these commitments and lowered the associated uplift.

Performance Test

NYISO routinely audits 10- and 30-minute non-synchronous reserve providers to ensure that they can provide the services that they sell. However, units that perform well during audits may still perform poorly during normal market operations, and it may be appropriate to suspend or disqualify poor performers, LeeVanSchaick said.

Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs (~$105K of uplift in 2021-Q1), LeeVanSchaick said. ■



DC Circuit Rejects FERC Logic on PJM 10% Adder

By Michael Yoder

The D.C. Circuit Court of Appeals on Friday rejected FERC's logic for approving a 10% cost adder in PJM's capacity market but without vacating the commission's 2019 ruling (*No. 20-1212*).

Circuit Judge Karen LeCraft Henderson wrote the opinion for the three-member panel, ruling that the commission's approval of the 10% adder was not just and reasonable and that it "did not provide a satisfactory explanation for its approval, which reasoned decision-making requires."

FERC approved the adder and other revisions to PJM's capacity market rules in an April 2019 order following the RTO's quadrennial revision. (*ER19-105*). (See *FERC to PJM: Clarify Allowable Costs for Energy Offers*.)

A *report* by The Brattle Group the previous year had suggested PJM change its capacity reference resource from a combustion turbine plant (CT), the standard used since the beginning of the capacity market, to a combined cycle plant.

Despite recommending the combined cycle plant, Brattle also acknowledged the rationale for staying with a "[combustion turbine]-based curve if PJM and stakeholders are highly risk-averse about ever procuring less than the target reserve margin." PJM ultimately decided to keep the CT as its reference resource but updated the energy and ancillary services (E&AS) markets revenue estimate by increasing the value of the reference resource's estimated offer to supply energy in the energy market by 10%.

The Sierra Club and consumer advocates for Delaware, Maryland and D.C. challenged the commission's approval of the 10% adder and the continued use of the CT reference resource. FERC denied the petitioners' request for rehearing. (See "Next Steps," *FERC: RGGI, Voluntary RECs Exempt from MOPR*.)

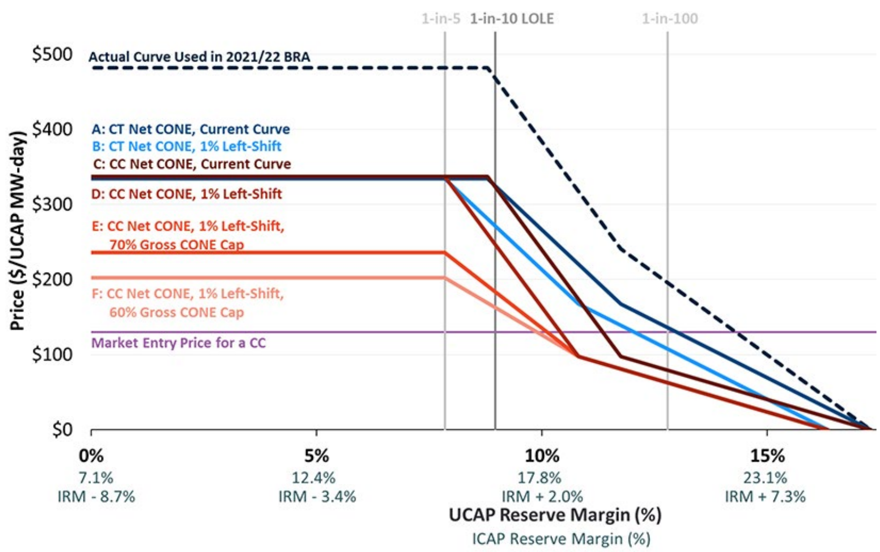
Use of Adder Unlikely

In her ruling, Henderson said evidence brought to FERC indicated that CTs may not utilize the 10% adder in their energy market offers.

The court cited research by economist James Wilson that found that if the reference resource incorporated the 10% adder, its net E&AS revenues would decline by up to 32% because it would reduce its competitiveness in the energy market. Wilson also said that most CTs "would face the uncertainties that underlie the 10% adder 'relatively rarely, if at all.'"

PJM's Independent Market Monitor said that many gas-fired generation resources, like the reference resource, exclude the 10% adder from their offers.

Brattle said its research found "mixed reactions" as to whether combustion turbine plants would face costs requiring an offset from the 10% adder. In the report, Brattle recommended that "PJM investigate this further and consider applying the 10% cost offer adder."



Analysis from 2018 by The Brattle Group showed that its updated calculations for cost of new entry (CONE) shifted the curve substantially down. Using Brattle's recommendation to use a combined cycle as the reference technology would also move the curve to the left. | *The Brattle Group*

The court said if no or few CTs ever use the 10% adder, then it "makes little sense" to include the adder for a hypothetical combustion turbine plant's E&AS revenue estimate.

"The net [cost of new entry] should estimate the costs and revenues of the reference resource based on accurate market signals and data," the court said. "Whether the type of supplier the reference resource is based on would utilize the 10% adder, then, is a relevant consideration. Simply because suppliers are permitted to utilize the 10% adder — and recognizing there are good reasons for them to be so permitted — we do not think it reasonable to assume the suppliers will utilize the 10% adder, especially when the evidence here indicates that the use of the adder would run counter to a combustion turbine plant's economic interest."

The court said FERC found that utilizing the 10% adder "improves [the] accuracy" of the E&AS revenue estimate. But it said the commission did not assess whether CTs would utilize the 10% adder or explain why such an assessment would be unnecessary.

"The commission's response to the contrary evidence can be described as little more than a hand wave," the court said. "It approved the use of the 10% adder because the adder's general use was already approved as just and reasonable and because including the adder would make the E&AS revenue estimate 'consistent with existing energy market rules.'"

The court did side with FERC in approving PJM's proposal to keep the CT as its reference resource. The petitioners suggested the use of a CT as the reference resource is unjust and unreasonable because a combined cycle plant would be "more just and more reasonable."

But the court said it's not its role to ask "whether a regulatory decision is the best one possible or even whether it is better than the alternatives." It said FERC found that combustion turbine plants "continue to serve a role in PJM's region," with more than 1,600 MW of CT capacity built in the RTO since the capacity market was adopted.

"The commission articulated a satisfactory explanation for its decision that the use of a combustion turbine plant as the reference resource is just and reasonable and substantial evidence supports that decision," the court said. ■

PJM News

PJM Board Approves MOPR Reform

Continued from page 1

Chair Mark Takahashi said voters selected PJM's proposal because it "accommodates state policy and self-supply business models," addresses "attempted exercises of buyer-side market power (BSMP)," and creates a "sustainable market design" by "keeping clearing prices consistent with supply and demand fundamentals."

The board cited the "overwhelming member support" of PJM's proposal during the critical issue fast path (CIFP) stakeholder process and the final vote as another reason for its selection. The board in April *directed* the RTO to use the CIFP process, which was designed to resolve controversial time-sensitive issues, marking the first time it was implemented.

PJM officials said they plan to work "diligently" to ensure the RTO files with FERC in time to have the changes incorporated into the 2023/2024 delivery year base residual auction scheduled for December. (See *PJM Proposes Shifting MOPR Determinations to FERC*.)

PJM CEO Manu Asthana said that, through the CIFP process, stakeholders "successfully tackled a complex issue in a compressed time frame, achieving both a workable solution and broad consensus behind that solution."

"This proposal ensures that our capacity market accommodates state policy and self-supply business models, avoids customer costs of double-procurement, addresses attempted exercises of buyer-side market power and creates a sustainable market design by keeping clearing prices consistent with supply and demand fundamentals," Asthana said.

PJM's Proposal

The PJM MOPR proposal calls for "maximiz[ing] transparency and market confidence" through identification of BSMP by the RTO and the Independent Market Monitor. It also proposes to "further clarify the actions of a state" that may "improperly interfere with bidding in PJM's capacity market and FERC's rate-making authority."

Market participants will be asked to sign attestations declaring they are not exercising market power or receiving state funds tied to clearing in the auction. PJM and the IMM will conduct "fact-specific, case-by-case reviews" if market power is suspected, and referrals will be made to FERC for a final determination.

The new rules will eliminate both the expanded MOPR created by FERC's December 2019 ruling and PJM's prior MOPR, which was limited to new natural gas resources.

In its letter issued Wednesday, the board said discussions involved several items stakeholders had included in the *matrix*, including a request to delay a MOPR filing to FERC, the creation of an emerging technologies MOPR exemption, considerations related to self-supply proposals and increased reporting on capacity auction results.

The board said it ultimately decided against amending the PJM proposal because it "could alter the members' intent as expressed in the vote" held on June 30. The letter said stakeholders can start further discussions on issues as they begin Phase 2 of capacity market discussions.

"We would like to sincerely thank the many stakeholders who invested time and energy to provide essential diversity of thought throughout this process," Takahashi said. "We view the stakeholder process as a true strength of the organization, as it provides a venue for viewpoints across the industry to be heard and deliberated upon."

PJM's Response

Adam Keech, PJM | © RTO Insider LLC

Adam Keech, PJM's vice president of market design and economics, said the MOPR proposal boiled down to three key points driving its design.

First, PJM wanted to ensure the proposal was "focused in" on BSMP, including attempts to exercise such market power.

The existing MOPR resulting from the December 2019 FERC ruling was too "broad" and went beyond the BSMP parameters, Keech said. Early in the CIFP process, he said, PJM received stakeholder feedback expressing the desire to refocus the MOPR on BSMP "the way it has been intended to since its inception and prior to the expansion" in December 2019.

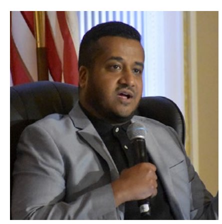
Keech said the second driving principle was to accommodate state policy and self-supply business models. He said the existing MOPR "puts up challenges" for entities using those types of models and that PJM wanted to avoid creating "barriers" as long as they're not attempting to exert BSMP.

The third proposal driver was to make market rules "sustainable," Keech said, with PJM looking to move away from market designs that attempt to "reconstitute clearing prices" that aren't consistent with the set of resources that cleared the auction.

"We felt in order to make the market rules sustainable, we had to make sure the markets adhere to the strict economic principles of making sure the prices reflect the supply and demand conditions in the market," Keech said.

Keech said the PJM proposal advanced overwhelmingly because of the work done with stakeholders inside and outside the CIFP meetings, incorporating input, considerations and concerns while still focusing on the RTO's three main drivers.

"It was a lot of work, a lot of listening and a lot of revisions to the proposal to try to address everybody's concerns and give them confidence that their concern would be addressed with the proposal but not to the detriment of the effectiveness in terms of mitigating buyer-side market power," Keech said.



Asim Haque, PJM | © RTO Insider LLC

Asim Haque, PJM's vice president of state and member services, said in just three months members "tackled one of the most high-profile energy policy issues in the country." Haque said PJM was "grateful" for the engagement by members in the expedited stakeholder process.

Haque said there was no trepidation in taking on the CIFP process even though it had never been implemented, saying the process was "highly negotiated" in Manual 34 and had a clear template for how to advance to the next steps.

PJM received "pretty clear signals" from FERC that some sort of MOPR reforms needed to be advanced quickly, and he knew the stakeholder body "would meet that call," he said.

"Our stakeholders really stepped up and were participants in all of the different critical issue fast path stages and certainly met and exceeded our expectations of participation," Haque said. ■

SPP News

MISO, SPP Solicit Ideas on Allocating Joint Tx Costs

By Amanda Durish Cook

While MISO and SPP continue to search for joint transmission projects that might ease crammed interconnection queues, they're opening the floor to stakeholder suggestions on allocating the projects' costs.

The RTOs surprised some stakeholders during a Wednesday teleconference by not coming equipped with a draft cost-sharing plan for seams projects that might result from their ongoing joint targeted interconnection queue study. The grid operators are trying to identify interregional transmission projects that could lighten their interconnection queues.

As part of the study, MISO and SPP late last month zeroed in on two expensive project clusters that would eliminate most flowgate congestion. The $424 million and $728 million options traverse South Dakota, Minnesota and Missouri. (See *MISO, SPP Name Projects to Help Queue Troubles*.)

SPP Vice President of Engineering Antoine Lucas said the novel study is an opportunity to wipe out "common barriers" to generation projects along the MISO-SPP seams. He also said the RTOs don't yet have a detailed proposal on how new transmission construction will be funded.

"We're not here today to discuss design-level ideas on cost allocation," Neil Robertson, SPP's interregional relations senior engineer, said.

Robertson said MISO and SPP could devise other benefit metrics beyond adjusted production costs, such as increased voltage support, accomplished renewable goals, heightened reliability beyond constraint relief, and greater interregional transfer capability.

"The transfer capability is a critical component of maintaining reliability," LS Power's Pat Hayes said. "I think the benefits are clearly measurable."

Apex Clean Energy's Richard Seide said he was disappointed the RTOs didn't bring possible cost allocation proposals to the table.

David Kelley, SPP's director of seams and tariff services, said MISO's and SPP's existing FERC-approved cost allocations haven't yet yielded any project construction on the seams.

"What we are looking for are stakeholders to come with their cost allocation ideas in a manner that would be acceptable to both generation and load," Kelley said. "We're not going to drive the discussion and tell you how projects are going to be allocated."

"What we'd really like is to develop a proposal … with the interests of those who will be sharing the costs," Lucas added.

Other stakeholders said the cost allocation discussion failed to address that the RTOs are still accepting project suggestions to ease their three most congested 345-kV flowgates on the Kansas-Missouri border near Kansas City. The three constraints are not addressed in the two project clusters.

MISO and SPP asked stakeholders to submit written ideas on cost allocation approaches.

"Any idea that can be thrown into the mix would be helpful," Robertson said. ■

| *Shutterstock*

Company Briefs

ACORE Welcomes New Members to its Board of Directors

The American Council on Renewable Energy (ACORE) last week announced the appointment of two new members to its board of directors: Urvi Parekh of Facebook and Martin Torres of BlackRock.

Parekh leads Facebook's renewable energy team, which is responsible for the selection, negotiation and management of renewable energy projects to meet the company's 100% renewable energy goal.

Torres is the head of the Americas for the renewable power group within BlackRock Real Assets and is responsible for leading investment and portfolio management activities in the region.

More: *ACORE*

GM Invests in US Lithium Project

General Motors last week announced it will make a "multimillion-dollar investment" to help develop Controlled Thermal Resources' Hell's Kitchen geothermal brine project near the Salton Sea in California.

The project could produce about 60,000 tons of lithium — enough to make roughly 6 million EVs — by the middle of 2024 if all goes as planned, said CTR CEO Rod Colwell. That would make the project the largest U.S. producer of lithium.

More: *Reuters*

Solar Financier Sunlight Lists on New York Stock Exchange

Shares of Sunlight Financial, the No. 2 provider of loans for residential solar in the U.S., began trading on the New York Stock Exchange this week.

Sunlight will merge with Spartan Acquisition Corp., a special-purpose acquisition company sponsored by investment firm Apollo Global Management. The deal is expected to bump Sunlight's valuation to $1.3 billion.

In addition to funding more than $4 billion in home solar loans since mid-2016, Sunlight expects to exceed $120 million in annual revenue this year.

More: *Canary Media*

Federal Briefs

Colonial Pipeline Could Face Daily Fine After Massive Fuel Leak

Colonial Pipeline could face daily fines of up to $200,000 per violation if it fails to improve the way it detects leaks in its U.S. pipeline system, according to a recent settlement with the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).

The agreement orders Colonial to find and use a better leak detection system across its entire network, citing several newly disclosed leaks over the years. A massive gasoline leak found in Huntersville, N.C., in August was called one of the worst in the state by then-Department of Environmental Quality Secretary Michael Regan, who now heads the U.S. EPA. The company eventually reported that almost 18 times more gasoline leaked from its pipe than its original estimate.

A PHMSA spokesman wouldn't say why the agency didn't issue a fine for the spill as part the settlement but pointed to the agreement, which calls for daily fines of up to $200,000 per violation.

More: *The Charlotte Observer*

EPA Recommends Army Corps of Engineers Not Grant MVP Stream Permit

The EPA recommended that the Army Corps of Engineers not grant Mountain Valley Pipeline a critical permit to cross several hundred streams in Virginia and West Virginia.

"EPA has identified a number of substantial concerns with the project as currently proposed, including whether all feasible avoidance and minimization measures have been undertaken, deficient characterization of the aquatic resources to be impacted, insufficient assessment of secondary and cumulative impacts and potential for significant degradation, and the proposed mitigation," EPA Wetlands Branch Chief Jeffrey Lapp wrote in a May 27 letter.

Among areas of concern are the Upper Roanoke watershed, which would experience 200 of the project's proposed 719 stream impacts, and the Middle New watershed, which would see nearly 100 impacts.

More: *Virginia Mercury*

More Than 75 Companies ask Congress to Pass Clean Electricity Standard

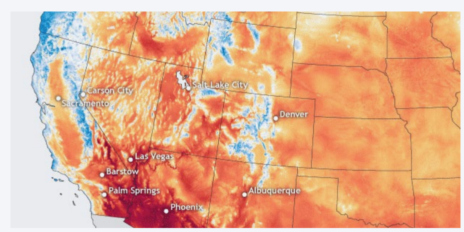
More than 75 major U.S. companies, including Apple, Google, Lyft and Salesforce, signed a letter last week urging Congress to adopt a federal clean electricity standard.

The companies urged the government to adopt a standard that achieves 80% carbon neutrality by 2030, with a goal of completely emission-free power by 2035.

The letter notes that the electrical power sector generates a 33% of nationwide carbon dioxide emissions. It is also the source of about 50% of natural gas use nationwide.

More: *The Hill*

NOAA Confirms June Hottest Ever in US



Last month was the hottest June ever recorded in the U.S., averaging 72.6 degrees, according to the National Oceanic and Atmospheric Administration.

The monthly temperatures were the highest scientists have seen in 127 years of tracking temperatures and broke the record set in 2016.

The European Union's Copernicus Climate Change Service reported that June was also the hottest June on record for all of North America.

More: *The Hill*

State Briefs

CALIFORNIA

PG&E Extends Shutoff Moratorium

PG&E last week announced that it will extend the moratorium on utility service disconnections through Sept. 30.

As part of the company's efforts to help customers manage their bills, PG&E will auto-enroll eligible customers in new extended payment plans by the end of September to coincide with the potential ending of the moratorium.

More: *PG&E*

COLORADO

Xcel Energy Seeks Another Rate Increase for Improvements, Updates

Xcel Energy-Colorado last week asked the Public Utilities Commission for a $343 million rate increase to pay for improvements and updates to its system.

If approved, residential customers would see their monthly electric bills rise by an average of $9.46 starting in September 2022.

The request follows another recent request from the company seeking a temporary rate increase to recover costs from the February storm.

More: *The Denver Post*

LOUISIANA

New Law Keeps Some Pollution Accidents Hidden from Public

Gov. John Bel Edwards last week signed into law a program that allows industrial facilities to conduct self-audits for certain pollution accidents and will allow those facilities to keep the records hidden from the public for up to two years.

The new law allows industries to self-report toxic spills and releases that wouldn't normally qualify for mandatory reporting to state or federal authorities as a way to provide the Department of Environmental Quality with information on minor accidents that it wouldn't normally receive. The law also states that "information contained in a voluntary environmental self-audit shall be held confidential by the department and shall be withheld from public disclosure until a final decision is made, or for a period not to exceed two years, whichever occurs first." However, the DEQ is required to publish any final decision once the secrecy period expires.

More: *Louisiana Illuminator*

MAINE

New Law Prohibits OSW Farms in State Waters

Gov. **Janet Mills** last week signed into law a bill prohibiting offshore wind farms in state waters. The bill is a compromise with fishermen aimed at siting projects farther from the heavily-used inshore waters.

The bill prohibits state and local governments from licensing or permitting the siting, construction or operation of wind turbines in waters that extend three miles from shore. It also creates an Offshore Wind Research Consortium with an advisory board that will advise the state on local and regional impacts from offshore wind power projects.

More: *Portland Press Herald*

MINNESOTA

AG Says Utilities Mismanaged Natural Gas Price Spike in February

Attorney General Keith Ellison's office last week concluded that state utilities mismanaged natural gas procurement after the February winter storm in the South, leading them to overbill customers for $380 million in wholesale gas costs.

The office said it is recommending the Public Utilities Commission allow utilities to recover only 53% of the roughly $800 million in costs they are trying to pass down to consumers, saying the companies could have reduced their wholesale gas bills during the run-up but failed to do so.

CenterPoint, the state's largest gas utility, estimated it would pass down roughly $470 million in storm-related gas costs. Xcel Energy ($251 million), MERC ($75 million) and Great Plains Gas ($11 million) are also seeking lofty recoveries. Ellison's office recommended the PUC allow CenterPoint and MERC to recover nearly 40% of those costs; Great Plains 14%; and Xcel 84%.

More: *Star Tribune*

MISSOURI

Gov. Parson Signs Bill Helping Utilities Shutter Coal Plants

Gov. Mike Parson last week signed into law a policy known as "securitization," which allows utilities to refinance debt they issued to build coal plants and close the facilities early without taking a financial hit. With the savings, the companies can invest in more renewable projects.

Securitization does not require utilities to shut down coal operations but does offer a financial incentive to do so.

Parson also signed legislation prohibiting local governments from banning natural gas hookups on newly built buildings.

More: *Missouri Independent*

MONTANA

Gianforte Withdraws Montana from Multi-State Climate Coalition

Gov. **Greg Gianforte** last week withdrew the state from the U.S. Climate Alliance, saying he "believes the solution to climate change is unleashing American innovation, not overbearing government mandates."

The alliance is a 24-state group committed to achieving the goals of the 2015 Paris Agreement. Former Democratic governor Steve Bullock had joined the alliance in 2019.

A representative of the Department of Environmental Quality said the Gianforte administration hasn't yet offered guidance on how to handle the Climate Solutions Plan.

More: *Montana Public Radio*

NEVADA

Lithium Project Receives Air Quality Permit

The Rhyolite Ridge Lithium-Boron Project recently was issued a Class II Air Quality Permit, according to Ioneer, the company behind the project.

The project, which encompasses a quarry, an overburden storage facility and an acid plant, went through a detailed review by the Division of Environmental Protection Bureau of Air Pollution Control. The permit is required for construction to begin at Rhyolite Ridge.

More: *Pahrump Valley Times*

NEW MEXICO

PNM Asks PRC to Reconsider Facebook Case

The Public Service Company of New Mexico last week filed for a rehearing of its proposal to expand a Facebook data center, saying its First Amendment rights were violated in a June 23 order by the Public Regulation Commission.

The commission's findings, PNM argues, ask the two companies "to adopt specific terms they do not support" and that the commission has ordered PNM and Facebook into mediation that neither needs nor desires.

PNM also offered the alternative of holding a workshop with the commission to clarify confusion related to the proposal.

More: *Santa Fe New Mexican*

San Juan Generating Station Taken Offline After Cooling Tower Collapse

Unit one of the San Juan Generating Station was taken offline two weeks ago after a cooling tower collapsed.

The cooling tower is necessary to operate the unit. Unless it is repaired, it will not be able to produce 170 MW of power for Public Service Company of New Mexico and Tucson Electric Power.

The plant was idle on the morning of July 6 with neither unit one nor unit four producing power.

More: *NM Political Report*

OHIO

Utilities to Refund Customers Fees from HB6

The Public Utilities Commission last week ordered Ohio Edison, Toledo Edison and Cleveland Electric Illuminating to refund a total of $27.5 million collected from House Bill 6 — the tainted energy bill with a guaranteed revenue provision.

Residential customers who use 1,000 kW of electricity in August will get a refund of $8.95 from Ohio Edison, $13.19 from Toledo Edison and $16.18 from Cleveland Electric Illuminating. Commercial and industrial customers will receive refunds of varying amounts.

More: *WTOL*

SOUTH CAROLINA

Dominion Agrees to Lower Rate Increase

Dominion Energy last week agreed with the Office of Regulatory Staff to a much lower rate increase of 1.46%, down from 7.7%, and promised not to raise rates until July 2023 barring an unforeseen economic disaster.

The agreement also requires Dominion to give up to $30 million to a fund to help less fortunate customers catch up on overdue bills, as well as make repairs and upgrades.

More: *The Associated Press*

Santee Cooper Fined for Air Pollution at 3 Plants

The Department of Health and Environmental Control recently fined Santee Cooper $22,950 for failing to control air pollution at three power plants.

The agency said the coal-fired power plants in Georgetown and Berkeley counties released elevated levels of particulate matter (soot), while the natural gas plant in Anderson County released too much nitrogen oxide.

The problems have been resolved and test results show the utility is complying with state law, according to DHEC and Santee Cooper.

More: *The State*

WASHINGTON

UTC Extends COVID-19 Protections for Utility Customers

The Utilities and Transportation Commission last week ordered electric and natural gas utilities to continue a moratorium on disconnections for nonpayment until Sept. 30.

Companies will continue to waive deposits for new customers and late fees through March 29 of next year.

More: *The Spokesman-Review*

WEST VIRGINIA

PSC Approves Appalachian Power, Wheeling Power Infrastructure Surcharge

The Public Service Commission last week approved a request from Appalachian Power and Wheeling Power to add a 6.12% surcharge to customers' bills that would allow the companies to recover costs from infrastructure investment projects.

The surcharge, which will total $44.1 million, will go into effect Sept. 1.

More: *Charleston Gazette-Mail*