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

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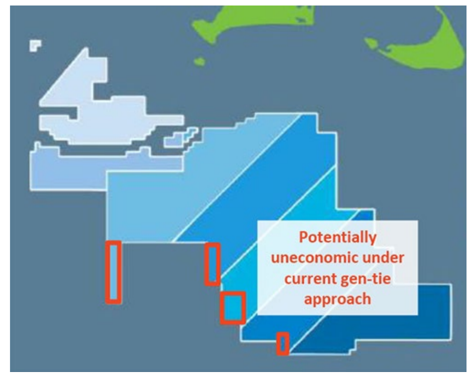
MOVING FORWARD ON MOPR

RTO Insider Editor Rich Heidorn Jr. moderated a webinar on PJM's expanded minimum offer price rule last week with (clockwise from top) Rob Gramlich, representing the American Council on Renewable Energy; Jim G. Davis, Dominion Energy; Kathleen Barrón, Exelon; Todd Snitchler, Electric Power Supply Association (EPSA); and Independent Market Monitor Joe Bowring (not pictured).| *© RTO Insider*

Brattle Study Highlights Benefits of Planned Offshore Grid

By Michael Brooks



| *Massachusetts CEC*

A regionally planned undersea transmission network interconnecting an expected surge in offshore wind projects would save New England developers and ratepayers more than $1 billion in onshore grid upgrades, The Brattle Group said in a *study* released Thursday.

Brattle prepared the study on behalf of transmission developer Anbaric Development Partners, which has proposed the

Continued on page 10

TOs Back PJM End-of-life Proposal

Both Sides Cry Foul on PJM Staff

By Rich Heidorn Jr.

PJM's transmission owners gave their long-awaited response to the push to open end-of-life (EOL) projects to competition and regional planning Friday, saying they support the RTO's proposal to increase its oversight of the process.

The TOs made their case during a fractious special meeting of the Markets and Reliability Committee in which both sides of the debate accused RTO staff of treating them unfairly.

For months, stakeholders seeking to make PJM responsible for EOL planning have bemoaned the TOs' refusal to engage in negotiations. On May 8, however, the TOs gave *notice* that they are supporting the PJM proposal and considering a Federal Power Act Section 205 filing to revise the Tariff to reflect it.

While conceding to load-side stakeholders in agreeing to increased PJM oversight of the EOL process, the TOs are trying to retain as much control as possible over the billion-dollar business of planning and building EOL projects.

With the TOs lined up behind PJM's proposal, LS Power announced Friday that it was withdrawing its proposal and joining with the "joint stakeholder" package by a group including American Municipal Power (AMP), Old Dominion Electric Cooperative (ODEC), state consumer advocates, the Public Power Association of New Jersey and the PJM Industrial Customer Coalition.

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In this week's issue

Stakeholder Soapbox

'In These Uncertain Times...'

By Vincent Duane

If another television commercial or online public service announcement intones this lazy, probably insincere attempt to offer comfort during our collective pandemic experience, I might throw my laptop or television out a window. I might — except, because I'm largely confined these days to a single-story building, it wouldn't result in the effect or satisfaction that is supposed to accompany this fit of pique. Cranky? Yes, I am! Along with many of my fellow pandemic inmates in cell block H. But while out in the exercise yard walking the dog recently, it struck me that another addition to our virus vernacular, "flatten the curve," might offer a useful way to think about emerging challenges facing electric grid operators.

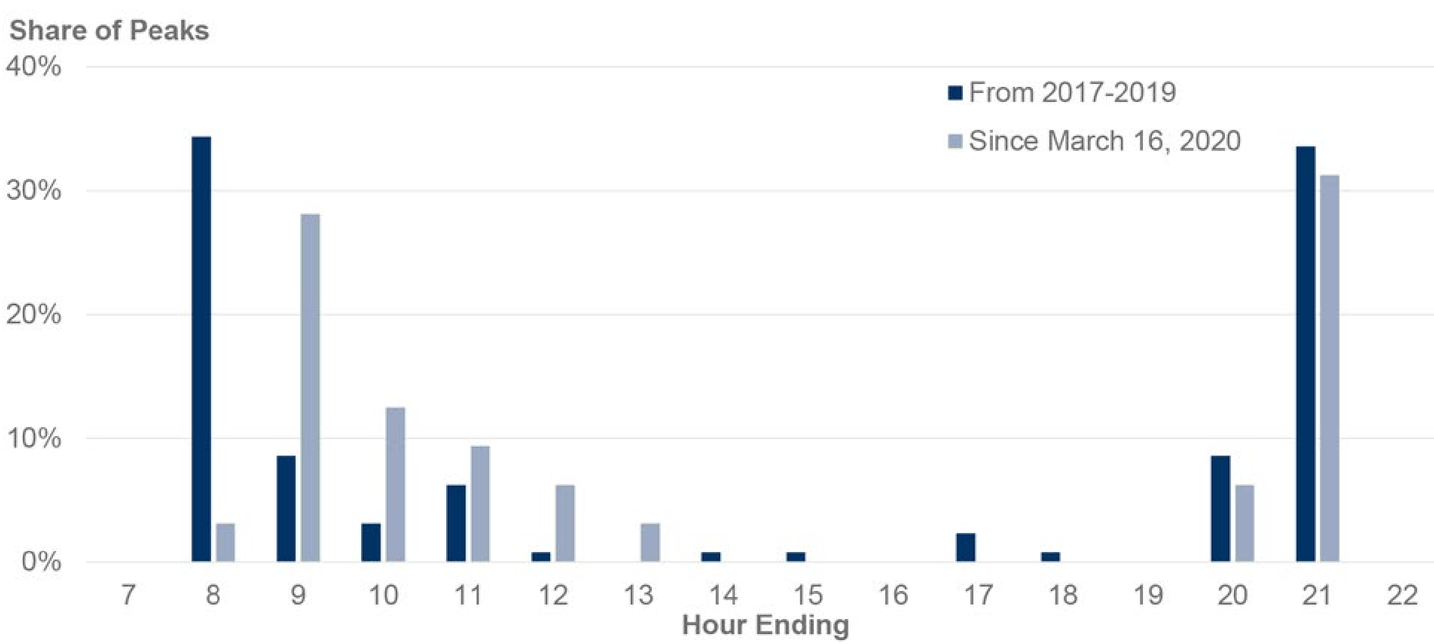
As we now unfortunately have all come to understand, in pandemic terms, "flattening the curve" refers to slowing the otherwise exponential spread of a virus to avoid overwhelming limited health care infrastructure and human resources. The analog in our industry is "flattening or shifting the peak," and it's not something we've historically done well.

Years ago, I likened grid planning and resource adequacy to a church designed to ensure every congregant, visitor, curious heathen, adherent to family tradition and the like was guaranteed a seat for Easter services, with 15% more pews added over the forecast attendance for good measure. As times changed, I shifted toward a more secular illustration: the example of a fictitious ordinance by the city of New Orleans requiring construction of hotels to cater to every person who might want to attend Mardi Gras, plus a prudent reserve. That's a lot of excess capacity to expect the local hospitality industry to carry over the many sweltering, hurricane-threatened months when most sane tourists would opt for Maine or Yosemite over Bourbon Street.

The point was not to suggest that electricity should be planned and provided like church pews or hotel rooms. Society values continuous, on-demand electricity differently and for many good reasons. But still, the laws of economics aren't suspended when it comes to our industry. Carrying large, fixed costs associated with infrastructure lying fallow for months on end is either quickly unsustainable or results in high tariffs that over time shift the supply-and-demand equilibrium, resulting in a suboptimal allocation of consumer and producer surpluses and reduced total economic well-being. In other words, in most industries, while shortage may not be a good thing, it is at least a necessary evil.

For grid operators and planners, demand is still largely unexposed or is inelastic to price. Shortage isn't an option. And the price of electricity, despite being delivered like a guaranteed hotel room during Mardi Gras, is still a good deal as a "value proposition" for most consumers. But from the perspective of those interested in designing organized wholesale electricity markets, the economic inefficiency of our industry's infrastructure profile keeps people working on demand response, advanced metering and regulatory reform to expose more customers to actual real-time prices for electricity in the wholesale market. Here, the hope is that prices can be harnessed to change consumption behavior to flatten peaks through a curtailment or temporal shift of consumption. As mentioned, despite huge theoretical promise, as an industry we have had modest success at best in identifying and controlling discretionary consumption through either price or programs.

Today, new fronts have opened to tackle this problem. The motivation here isn't the economic inefficiency associated with transmission and generation infrastructure in waiting. Rather, the concern is operational. Public tolerance to ever-expanding infrastructure, particularly transmission, is limited. Let's face it: Electric infrastructure has less aesthetic appeal than a cathedral and arguably even less than a Trump Tower hotel. More salient, is the changing generation resource mix and, in



Timing of March/April weekday peaks in PJM | *PJM*

Stakeholder Soapbox

particular — through policy mandate, customer preference or otherwise — the increasing penetration of intermittent, renewable wind and solar generation. We've all heard of CAISO's "duck curve" and seen ramp rates become steeper year after year. In a carbon-constrained world, the role of flexible natural gas generation to "back up" and follow load is viewed as a temporary solution at best. So, we redouble efforts to conform an uncooperative supply curve populated by intermittent generation to an inviolate load curve. We ruminate over ideas such as building more transmission to move solar power from Arizona at the speed of light to meet the 8 a.m. morning pick-up in Los Angeles when the sun is still low in the sky over coastal California, and then push overabundant California solar back to Phoenix as the sun begins to set out there. What about batteries and the promise of other advanced clean technologies to add to our supply mix? It's old news to note that increasing reliance on renewable resources is creating new challenges for system operators responsible for reliably ramping a system up and down to meeting its peaks.

Fine. But what has the pandemic got to do with any of this? The answer is what today's grand and involuntary social experiment shows about grid performance and the attendant price outcomes associated with new and different load curves. And while quarantines and shutdowns may persist, they are finite. So, the more interesting point to consider is how more permanent social distancing, work from home and staggered industrial production scheduling could change the load shape, and the grid operation, carbon and economic implications that in turn would follow from this change.

Recently, PJM published data illustrating aggregate impacts of the pandemic situation on its operations over the past six weeks. Of course, it showed overall energy consumption had declined across the region, in a range of about 6 to 8%. It also showed that the peaks had declined by a greater amount — more like 10 to 12%. But things get more interesting looking at the ramp or load shape. Yes, the morning pick-up started later, but it also appears less concentrated in the 7 to 9 a.m. hours and spread out over a longer time period — a "flattening of the curve," if you will. Other operators are also showing evidence of a more gradual and delayed morning peak just like PJM; implications to the evening peak are less conclusive.

I'm not one to characterize anything associated with our current human health and economic catastrophe as a "silver lining." But very early observations suggest that certain "new normal" post-COVID scenarios affecting how society lives and works may change load behaviors in a way that decades of price incentives and regulatory programs have largely failed to do — behavioral changes that cause a temporal shift in electricity consumption, flatten the peak and, thus, reduce the strain on a supply side increasingly challenged to meet peaks as it transitions toward cleaner, carbon-free resources.

To further burden the analogy, a monthlong Mardi Gras allowing access to more people on less costly terms may be less intense, less fun and have a less obvious crescendo, but it's probably healthier. More gradual load curves that reduce reliance on fossil-fueled, load-following generation promise beneficial carbon reductions while buying additional time for the development of clean supply side and storage technologies.

It remains to be seen — in fact, I have heard these are "uncertain times" — whether we will return to the "good old days" or instead a "new normal" of social distancing with different patterns of work and life. I hope it's Door No. 1. But the thought nagging me is that we might be better positioned to address our other evolving global crisis, the climate, if we are forced for health reasons to change how we live and work and, as a consequence, we flatten the curve; that is to say, the load curve. ■

Vincent Duane is presently consulting through his firm Copper Monarch, LLC. He was previously the Senior Vice President: Law, Compliance & External Relations at PJM Interconnection, LLC.

CAISO/West News

CAISO Predicts Adequate Summer Capacity

Low Hydro, Limited Imports Late in Season Could Heighten Risk

By Hudson Sangree

California should have enough capacity to get through this summer's peak demand but dwindling hydropower and limited imports during late-season heat waves could strain supply, CAISO said Friday.

"Projections for summer 2020 show that the CAISO faces a low but somewhat increased risk of encountering operating conditions that could result in operating reserve shortfalls than was projected for 2019," CAISO's annual *Summer Loads and Resources Assessment* concluded.

CAISO's summer demand is expected to peak at 45,907 MW, a negligible increase from last year's weather-normalized peak of 45,826 MW. The increased risk this year compared with 2019 comes from lower-than-normal hydro conditions that could be "particularly impactful in late summer" when reservoirs are at their lowest.

California's snowpack from winter storms is the primary source of water during the state's dry months from late spring through early fall.

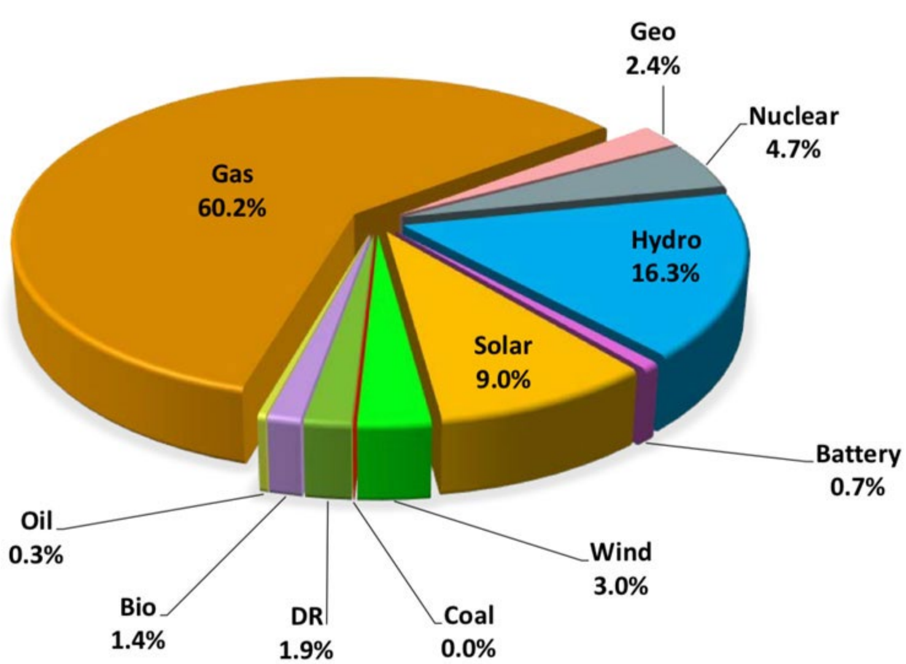
The statewide snow-water content in mountainous areas, including the Sierra Nevada, was 63% of average at its peak on April 7, the report said.

The state's major reservoirs were filled to 101% of average in April, but the snow that gradually melts and refills the reservoirs is far less than last year. On April 11, 2019, the statewide snow-water content was 161% of average.

Pacific Northwest hydropower, a major source of imports for California, is expected to be about the same as last year. For instance, the Northwest River Forecast Center projected the April-to-August reservoir storage at The Dalles Dam on the Columbia River to be 95% of average. It was 94% of average in 2019.

California, however, is competing more with other Western states for a tightening supply of electricity as coal plants retire. (See *Western Resource Adequacy Program in the Works*.) Moreover, the state's peak demand has shifted to later in the day, as solar energy diminishes and stops.

CAISO reiterated its concern with the situation last week.



CAISO's breakdown of available 2020 summer peak capacity shows gas remains a major resource. | *CAISO*

"The CAISO will be at the greatest operational risk of a system capacity shortage later in the summer if hot weather occurs that extends beyond the CAISO footprint and diminishes the availability of surplus energy in neighboring balancing authorities for imports into the CAISO during peak hours when solar production is near or at zero," it said.

The 2020 summer report didn't assess risk from transmission outages because of wildfires but acknowledged it "could hinder imports during critical supply conditions."

Planners didn't have enough data to factor in the effect of decreased load on summer demand from the COVID-19 crisis and California's stay-at-home order.

After Gov. Gavin Newsom issued the order in March, weekday loads were down by about 7.5% during peak-demand times and down 5% during off-peak times; weekend load reductions were 3% during peak demand and 1% off-peak, CAISO has said. (See *Western EIM Governing Body Hears COVID-19 Updates*.)

CAISO and the California Public Utilities Commission have been worried about capacity shortfalls that were projected to start as early as this summer and grow significantly worse beginning in summer 2021.

The CAISO assessment could allay fears about capacity shortfalls this summer, but next year may be another story.

Last September, Mark Rothleder, CAISO vice president for market policy and performance, told the CPUC that the state was facing shortfalls to its capacity needs, including a 15% planning reserve of 4,400 MW in 2021 and 4,700 MW in 2022. (See *CAISO, CPUC Warn of 'Reliability Emergency'*.)

"The issue is not so much at the peak hour," Rothleder said. "It's at the near-peak hour as the sun goes down."

CAISO and the CPUC have been working to address the issue. The commission ordered some older once-through-cooling plants that were scheduled to retire to remain open through 2023. It also ordered all load-serving entities under its oversight to collectively procure 3,300 MW of capacity, on a basis proportional to projected load, by August 2023. (See *California PUC Votes to Keep Old Gas Plants Operating*.) ■

CAISO/West News

FERC Rejects PSCo's Interconnection Process

By Hudson Sangree

FERC on Friday rejected Public Service Company of Colorado's proposed changes to its large generator interconnection procedures, saying the changes could give the utility an unfair advantage and hinder competition (*ER20-1153*).

"PSCo's proposed generator replacement process may result in a more favorable interconnection process for PSCo's own generation and make it more difficult for its generation competitors to enter the market," FERC said.

The generator replacement process, with its revised criteria, would allow PSCo's generation facilities to go through a foreshortened process, "whereas new generation seeking to compete would be required to go through the full interconnection process," the commission said.

Because 60% of PSCo's existing designated network resources are generators owned by itself or an affiliate, "we find that the proposed generator replacement process could give PSCo an undue preference," FERC said.

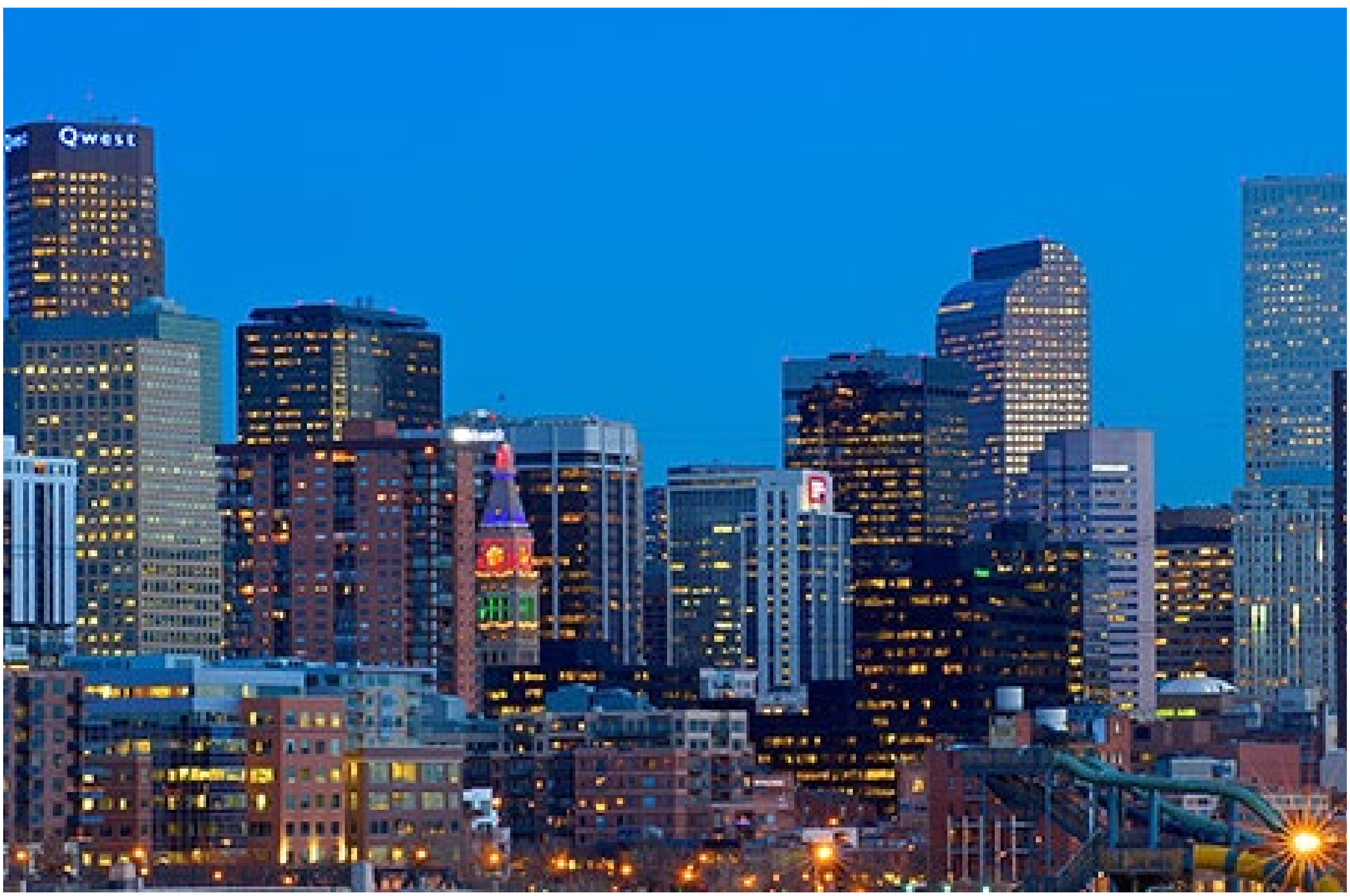
PSCo's changes were sought under FERC Order 2003, in which the commission required public utilities that own or operate transmission to file generator interconnection procedures for facilities with a capacity of more than 20 MW. The order provided for *pro forma* large generator interconnection procedures (LGIP) but allowed for variations consistent with or superior to the standard LGIP.

Order 2003's interconnection procedures were meant to "limit opportunities for transmission providers to favor their own generation and to facilitate market entry for generation competitors by reducing interconnection costs and time," FERC said.

PSCo, a wholly owned subsidiary of Xcel Energy, failed to show its proposed changes were equal to or better than Order 2003's standard LGIP, FERC said. In fact, the changes were likely to undermine the order's intentions, it said.

"Without the proposed generator replacement process — that is, under the *pro forma* LGIP provisions — replacements for PSCo's existing generation and new generation (whether developed by PSCo or a third party) will all be required to go through the regular interconnection process and interconnection queue," the commission said. "This will allow all generation to compete on a level playing field, including accessing released interconnection capacity following an existing resource's retirement.

"For these reasons, we find that PSCo's proposed generator replacement process is not consistent with or superior to the pro forma LGIP," the commission said. ■



Xcel's Public Service Company of Colorado serves 1.5 million customers in Denver and surrounding areas.

ERCOT News

EDF Sees ERCOT Value in Demand-side Solutions

By Tom Kleckner

The Environmental Defense Fund last week released a report on ERCOT's energy-only market that concludes it can meet future demand growth, increase grid resilience and keep energy costs down through demand-side solutions.

Titled "Resource Adequacy Challenges in Texas: Unleashing Demand-side Resources in the ERCOT Competitive Market" and written by energy consultant Alison Silverstein, the *report* posits that ERCOT's market design "works efficiently and effectively, and it should be maintained."

It also says that distributed energy resources, such as solar and storage, and demand-side measures, such as energy efficiency and automated and price-responsive demand, can respond to prices as well as to grid management signals.

"These assets should be used to de-risk the electric system by reducing peak load and ancillary service needs," Silverstein writes. "All of these resources can be coordinated and integrated with advanced monitoring, forecasting, analytics, communications and controls to integrate and balance demand with supply for reliable, affordable and sustainable electric service."

"The whole demand side was a little bit of a surprise," Silverstein told *RTO Insider*.

She said she began the report by considering whether competition within ERCOT's market would continue to work and whether there would be "fingernail chewing every summer," given the grid operator's 10.6% reserve margin. (See *ERCOT Sees Summer Repeat: Record Peak, Tight Reserves*.)

"But when I started looking at the characteristics of the demand side today as we get more energy efficiency and automated demand-side capabilities, and we get more photovoltaic and battery storage on the customer side, we have the potential to make demand dispatchable," Silverstein said. "We could manage demand to better balance supply, which is dispatchable and intermittent. Rather than put all the pressure on supply alone, demand-side measures offer many benefits to customers, besides holding down the prices."

Demand-side resources can reduce the burden and cost of assuring adequate supply and flexibility services and also protect customers while improving system and community resilience, she said.

As Silverstein was buttoning up the report in February, the COVID-19 pandemic was upending life for much of the world. Soon thereafter, Texas was hit by a collapse in oil and gas prices, thanks to a production price war between Russia and Saudi Arabia, and a 30% drop in U.S. oil consumption.

Texas produces more than 42% of the nation's crude oil, Silverstein said, but the *U.S. rig count has fallen* for nine straight weeks to 374. A year ago, 988 rigs were in operation. Texas is home to about half of those rigs, most in the Permian Basin of West Texas. On May 12, West Texas Intermediate Crude prices were trading around $25/barrel, a far cry from the halcyon days of $150/barrel oil.

Asked about the oil slump's effect on the ERCOT market, Silverstein said simply, "It isn't going to be good."

West Texas' oil fields provided the fastest-growing demands for electricity until recently, she said, but as those wells are shut in, both demand and the need for oil field workers will drop. The oil and gas industry accounts, directly and indirectly, for about one in six of the state's jobs.

"That means we both lose the direct consumer of electricity and the electricity demand of all those people employed in oil and gas and those jobs they supported," she said. "It'll have a huge ripple effect for demand."

The reduced pressure on demand and prices will lead to the most uneconomical power plants shutting down. "Some of those plants in [ERCOT's interconnection] queue will vaporize," Silverstein said, leading to continued operation of older plants.

In the report, Silverstein said both COVID-19 and the oil slump will create long-term shifts in ERCOT demand, leading to a "multi year" drop in residential and commercial energy use. They will "delay, but not negate" the region's long-term challenges, she wrote.

"Texas' energy profile will continue to change and become more complicated," the report says. "New technologies and energy resources — particularly more demand response and energy efficiency — offer ways to improve resilience, maintain reliability, reduce costs and further modernize ERCOT's successful competitive market."

Alison Silverstein | © *RTO Insider*

The report outlines four recommendations to maximize demand-side resources' potential:

- Eliminate legislative and regulatory barriers that make it harder or less attractive to deploy demand-side resources, including any barriers to their participation in the ERCOT market.
- Rely more heavily on energy efficiency by strengthening standards and requirements and allowing local governments to set more aggressive standards for their jurisdictions.
- Require that any facilities planning publicly funded renewable energy additions first undergo an energy efficiency audit to ensure the project's prudent use of funds, a move EDF said would save energy and avoid investing in unnecessary infrastructure.
- Support local and government investment that creates new funding mechanisms in demand-side management programs and technology.

EDF said the report is the first to clearly outline the relationship between supply and demand for the state's resource adequacy and present how demand-side resources can fit within Texas' existing market.

John Hall, EDF's director of regulatory and legislative affairs, said demand reduction has always been part of ERCOT's market. However, he said, meeting demand continues to be accomplished primarily by increasing generation capacity.

"We cannot build our way out of this," Hall said in a *statement*. "Demand-side solutions are the cheapest sources of new electricity. They're certainly cheaper than building new power plants, and they are often more cost-effective than utility-scale wind and solar." ■

ERCOT's Summer Reserve Margin up to 12.6%

Texas Grid Operator Still Expects Record Demand, Despite COVID-19

By Tom Kleckner

ERCOT said Wednesday it still expects record demand this summer and the potential need for emergency measures, despite a drop in load from the COVID-19 pandemic's continued effect on the Texas economy.

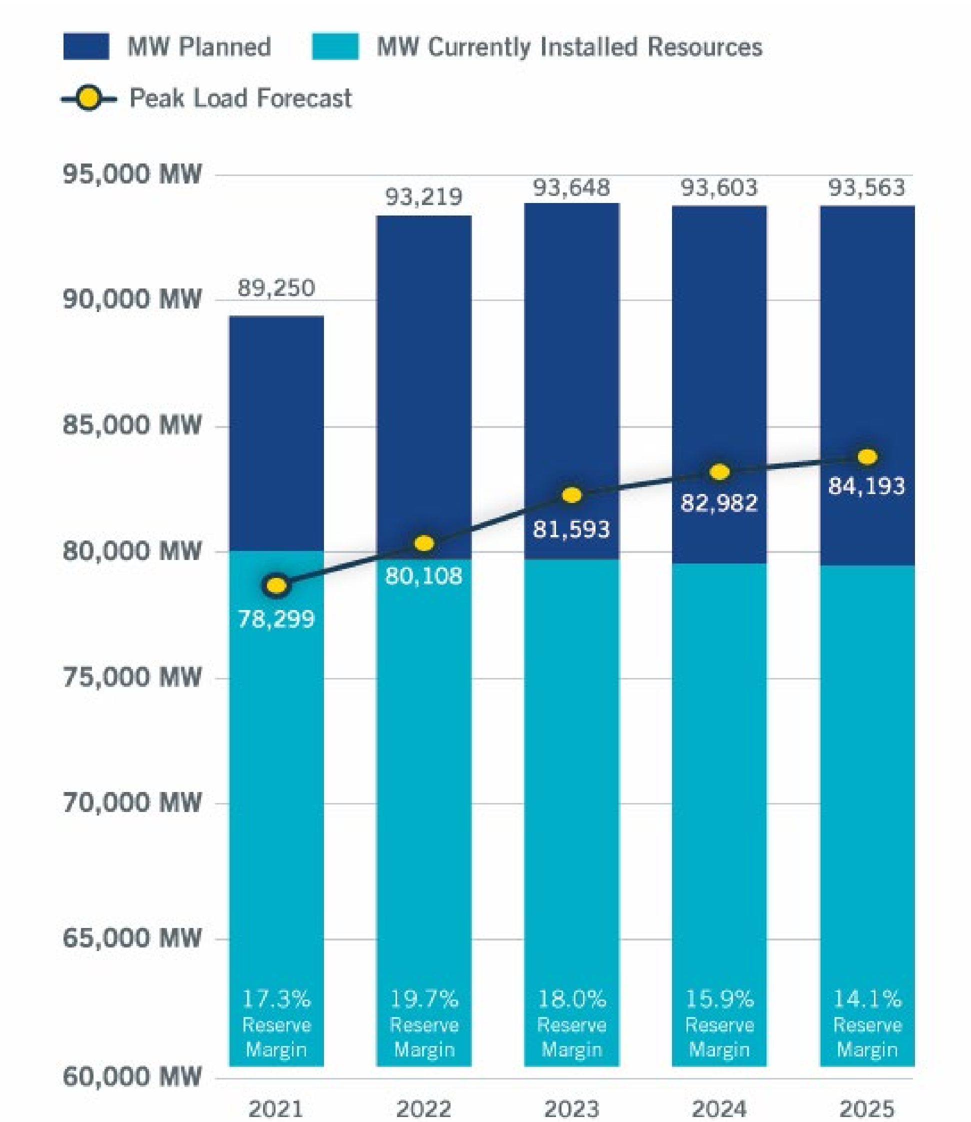
In making its *final resource assessment* for the summer months, the grid operator dropped its peak load forecast to 75.2 GW, almost 1.5 GW less than its preliminary assessment. However, it is still higher than last August's all-time record demand of 74.8 GW.

The pandemic has reduced *weekly energy usage* within ERCOT's footprint by 3 to 4%.

"There is a lot of uncertainty in today's world, but we are confident that Texas will still be hot this summer," CEO Bill Magness said in a *statement*.

Given the expected drop in demand and capacity additions since the last seasonal adequacy resource assessment (SARA), staff adjusted the summer reserve margin to 12.6%, up from 10.6%. Seven wind, solar and storage projects, totaling 276 MW of summer peak contributions, have begun commercial operations since the March SARA.

ERCOT says it will have enough capacity to meet summer's expected record demand.



ERCOT's peak load forecast through 2025 | *ERCOT*

ERCOT said that even with 82.2 GW of capacity available this summer, energy emergency alerts are still possible should there be extreme weather, low wind generation or higher-than-normal generation outages. The grid operator called two EEAs last summer, when it had a reserve margin of 8.6%. Demand did not reach record peak levels either day, but wind production was unexpectedly low and thermal generation outages were high. (See "ERCOT CEO Briefs Commission on Summer Performance," *Texas PUC Briefs: Aug. 29, 2019*.)

Pete Warnken, ERCOT's manager of resource adequacy, said the risk of an emergency is still present but less likely with a reserve margin that is almost 50% higher. "We anticipate the risk is now lower with typical grid conditions," he said.

The grid operator also released a *preliminary SARA* for the fall — 6.8 GW of additional capacity will help meet a predicted peak demand of almost 61 GW — and an updated capacity, demand and reserves (CDR) *report*.

Using pre-COVID load forecasts because of uncertainty over how the pandemic will affect future years, the CDR report forecasts reserve margins of 17.3% and 19.7% in 2021 and 2022, respectively. ERCOT has approved 2.3 GW of resources for commercial operations since the December 2019 CDR, and staff have also included 6.5 GW of planned resources.

Preliminary data provided by generation project developers indicate the grid operator will have almost 18 GW of planned capacity additions for summer 2021, much of it renewables and some small, flexible gas-fired resources, ERCOT said. ■

ERCOT News

Texas Public Utility Commission Briefs

New Rules Add Cybersecurity Monitor, Coordination Programs

Texas regulators last week adopted *rules* establishing a cybersecurity monitor and coordination program for investor-owned, municipal and cooperative utilities that count on their voluntary participation (*49819*).

The amendments to the Texas Public Utility Regulatory Act (PURA) don't require utilities to participate or to submit documents to the monitor. Utilities have made the rules' voluntary nature a key issue in the proceeding.

PUC Chair DeAnn Walker makes a point during the commission's May 14 open meeting.

But that left members of the Public Utility Commission nonplussed over comments made in the docket. Chair DeAnn Walker said during the commission's open meeting Thursday that she was "taken aback" and "floored" by some of the stakeholders' comments "and some of the people making those comments."

The amendments are the result of two bills approved last year by the state legislature. *Senate Bill 64* established the cybersecurity coordination program to share guidance on best practices, while *SB 936* set up the cybersecurity monitor.

"Over the years, we have had input from the legislators that they clearly wanted something like this," Walker said.

Commissioner Arthur D'Andrea

Commissioner Arthur D'Andrea said that he too was "taken aback" by the utilities' comments, noting that the PUC has stood " shoulder-to-shoulder" with its stakeholders during the recent legislative session.

"While [the program is] voluntary, this is not an audit," he said. "We want to protect their data, but we do expect participation and cooperation."

When several utilities asked that "voluntary" be added to the rule, the PUC responded by saying the "voluntary nature of participation … is made clear throughout the rule."

Monitored utilities will contribute to the program through their administrative fee to ERCOT. Those outside the ERCOT footprint will pay for the monitoring under a separate fee.

Any Texas utility "may" participate in the cybersecurity coordination program at no cost.

Commissioners Defend PUC Staff

Walker and D'Andrea both defended commission staff after they felt staff's comments on an ERCOT Nodal Protocol revision request were devalued in a grid operator stakeholder meeting last week (*NPRR1020*).

PUC staff filed joint comments with ERCOT staff on NPRR1020, which clarifies that emerging battery storage technologies can be interconnected and operated as a resource. The change proposes to add a definition for "integrated battery storage system" (IBSS) and modifies the definition of "wholesale storage load" (WSL) to include IBSS.

PUC staff did not sign their individual names to their comments, while ERCOT staff did. During the Protocol Revision Subcommittee's (PRS) meeting Wednesday, at least one stakeholder questioned why PUC staff didn't sign their names, according to another stakeholder who requested anonymity.

"They wanted a name of a particular staff member. I find that offensive," said Walker, who relayed her understanding of the PRS meeting based on a phone call she had received from staff.

PUC staff said PURA rules already allow for storage system loads integrated into a single container to be eligible to receive WSL treatment. They said the current IBSS definition "may arbitrarily exclude some integrated battery systems that do not meet all of the criteria specified in the proposed definition."

"Therefore, [PUC] staff and ERCOT suggest revisions … in an effort to provide clearer guidance and minimize arbitrary treatment in extending WSL treatment to integrated battery systems," agency representatives wrote. "The definition should focus on the characteristics that support extending WSL treatment to [storage systems] integrated into a single container instead of adding a new technology category to the WSL definition, which already includes the term 'batteries.'"

"Technology is going to change. We have to be nimble to be able to change and do things with it," Walker said. "If staff believes [NPRR1020] falls under our current rule, I find it offensive that people at ERCOT are challenging and saying that staff has no rights and has to [identify themselves]."

"Staff's position is an institutional voice, and that should be good enough," D'Andrea said. "This [NPRR] is already two-and-a-half years in the making. I'm already embarrassed by how long it's taken us to nimbly account for this technology. This is the kind of thing Texas should be able to adapt to and that the markets should be able to handle well."

The Wholesale Market Subcommittee agreed to take up NPRR1020, and ERCOT staff said it would schedule a workshop on the issue. Like the PRS, the WMS reports up to ERCOT's Technical Advisory Committee.

ERCOT and PRS Chair Martha Henson, with Oncor, both declined to comment.

Customer Protections Extended to June 17

The commission added another month to its pandemic-related provision that suspends customer disconnections for non-payments, from May 15 until June 17, acknowledging concerns that extensions of the emergency order are being issued open meeting by open meeting (*50664*).

"I was really hoping at this point we would be further along in our reopening of the state," Walker said, pointing to the Texas Panhandle and the rising numbers of COVID-19 cases related to meatpacking plants. The state reported *more than 700 cases* on Saturday alone.

"Those customer bills will continue to rack up," she said. "At some point, they're going to get a bill they have to pay."

"I'm concerned we're just starting to see the effects of economic disruption," Commissioner Shelly Botkin said.

The *order* applies to low-income customers of vertically integrated electric utilities that operate outside of ERCOT: Entergy, El Paso Electric, Southwestern Public Service and Southwestern Electric Power Co.

In other actions, the PUC approved an amendment to the PURA that adds retail brokers or aggregators to those governed by customer protection rules for retail service (*50406*). ■

— Tom Kleckner

ISO-NE News

Brattle Study Highlights Benefits of Planned Offshore Grid

Continued from page 1

Southern New England OceanGrid, an open-access network that would interconnect future offshore wind projects in the federal wind lease area off the coasts of Rhode Island and Massachusetts.

Brattle compared the costs of such a proposal to the expected costs under the current approach of each offshore project using one generator lead line (GLL) to interconnect to an onshore point of interconnection (POI). Four projects under development worth 3,112 MW — Vineyard Wind, Mayflower Wind, Revolution Wind and Park City Wind — already plan to use their own GLLs.

But New England will need possibly more than 40 GW of offshore wind by 2050 to meet states' decarbonization goals — or as much as 1.5 GW every year, Brattle said. If every project followed the current approach, it could lead to major onshore transmission overloads, the group found.

"These overloads, and the massive amounts of marine cabling, could be reduced dramatically with a planned approach," Johannes Pfeifenberger, a principal at Brattle, said in unveiling the study during a webinar hosted by Massachusetts-based State House News Service on Thursday.

Pfeifenberger explained that because projects would share HVDC lines under a planned approach rather than individual HVAC lines, in addition to reducing costs and congestion, a planned grid would also lessen the amount of marine trenching needed, mitigating damage to the undersea environment. Power line loss would also be reduced, as the length of cables would be shorter.

Brattle broke down its comparison into two phases: one based on states' current procurements besides the four projects already expected to use GLLs (2.8 GW) and an expected extra 800 MW; the second based on using up the remaining lease area (about 8.2 GW).

Under both the baseline scenario, which assumes projects continue to use their own GLLs, and the planned scenario, Phase 1 would see 3,600 MW in transmission capacity built. But under the current approach, nine HVAC lines stretching a combined 694 miles would be built, with "significant onshore transmission overloads" in Southeastern Massachusetts. Under the planned scenario, only three HVDC lines totaling 356 miles are built, with only "minimal" congestion near the POI at the Mystic Generation Station in Everett, Mass.

'A Bowl of Spaghetti'

The differences become even more stark in Phase 2. In the baseline scenario, onshore transmission becomes even more congested and spreads across Massachusetts, Rhode Island and Connecticut. More individual GLLs are added, crisscrossing each other under the sea before they reach their POIs: "a bowl of spaghetti," as Pfeifenberger described it, "of many lines; 18 [to] 20 lines emanating from the offshore wind lease area and interconnecting at various points onshore."

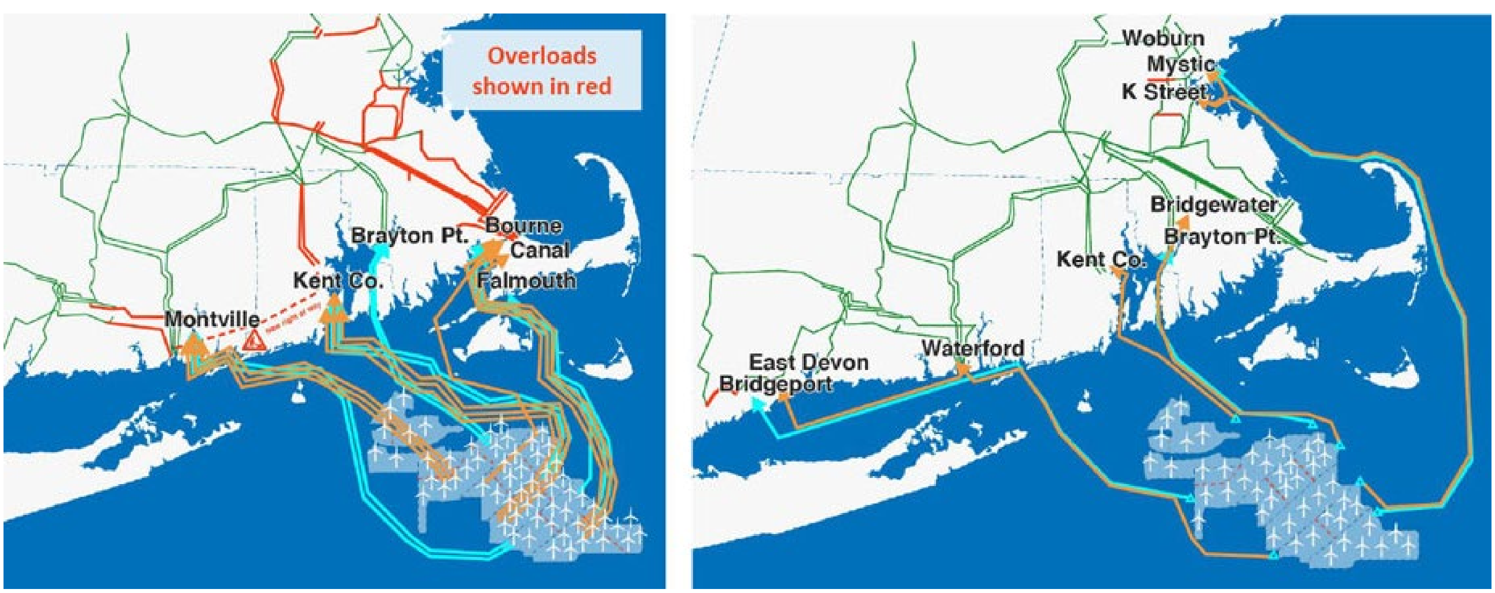
In the planned scenario, additional HVDC lines are bundled with existing ones, untangling the "spaghetti" to create only four discernable routes to about the same number of POIs.

Overall, under Brattle's planned scenario:

- total transmission costs are 10% lower, with a 65% reduction in onshore upgrade costs offsetting an expected 22% increase in offshore construction costs;
- line losses are about 40% lower;
- line mileage is about 49% lower; and
- ratepayers would save about $20 million annually.

"Importantly, you also create more competition under the planned approach," Pfeifenberger said. "You would have people compete for building the offshore grid; then you would have wind developers for interconnecting their projects to onshore grid locations. ... Offshore wind developers would not have to worry about the transmission component of their projects."

The risk of stranded assets is also lessened, Brattle said.



The Brattle Group compared two different scenarios: one in which each offshore wind project interconnecting to the grid uses its own individual line (left), and another in which a shared, open-access offshore grid is planned. | *The Brattle Group*

ISO-NE News

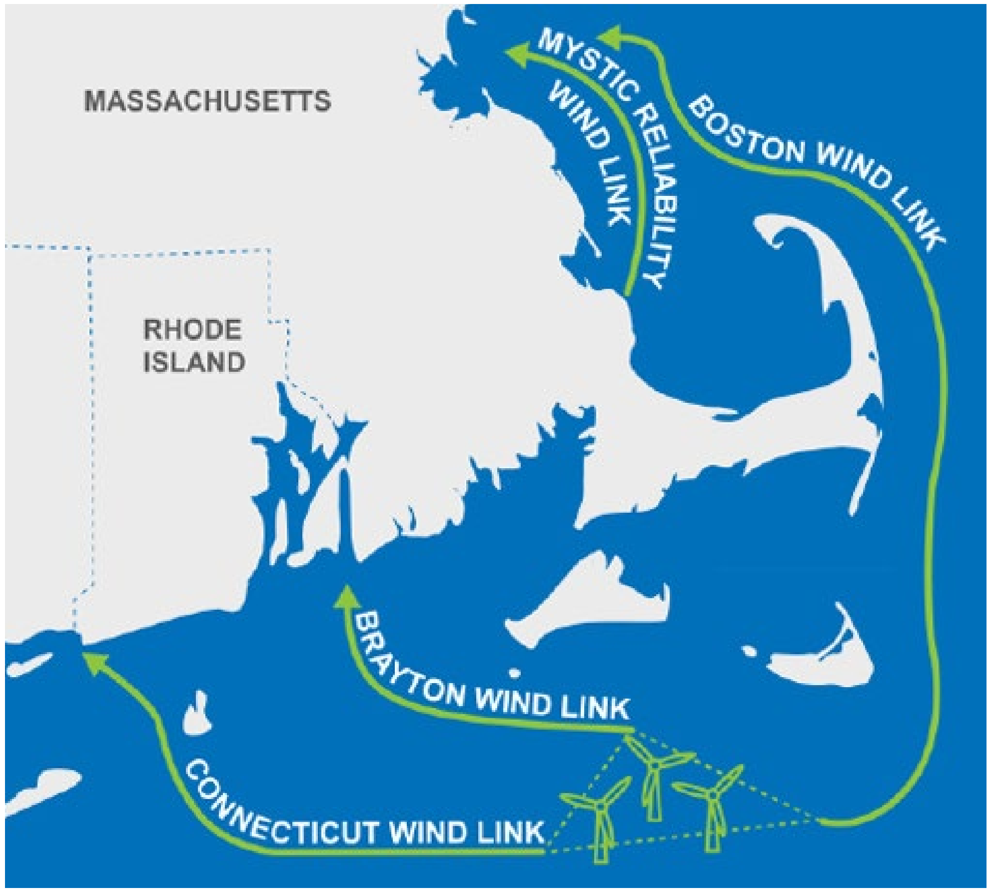
"Without a well-planned offshore grid, some of the existing offshore lease sites may not be economic to develop," the study says. "After developers interconnect the bulk of their lease sites, it may be cost-prohibitive to interconnect the residual areas (of perhaps 50 to 250 MW each) using AC generator lead lines sized to carry about 400 MW each."

There's also "a limited number of landing sites for offshore wind transmission in New England," said Pfeifenberger's associate at Brattle, Walter Graf. "If each offshore wind project requires a separate cable interconnection to the onshore transmission system, viable cable routes become really constrained."

Anbaric and other transmission developers, eager to capitalize on the growing interest in offshore wind, have long been advocating for the benefits of offshore transmission planning. (See *Anbaric Pushes Offshore Grid Plans*.) But Brattle's study appears to be the first attempt to quantify those benefits.

"Brattle's research underscores the pivotal role of transmission policy in the development of New England's offshore wind industry," Anbaric said in a statement. "By relying on landing points closer to population centers and at robust onshore grid locations, a planned system reduces grid congestion and the need for expensive, disruptive onshore transmission projects that could hinder the growth of offshore wind."

States have shown interest in such an approach. (See *Mass. DOER Explores Transmission for OSW*.) And webinar attendees, many of which were state regulatory staffers, were eager to get their hands on the Brattle study, if the



Anbaric's proposed Southern New England OceanGrid | *Anbaric*

side chat room in the webinar was anything to go by: Pfeifenberger repeatedly linked to his presentation as Graf spoke in response to requests from those apparently unaware they could see his previous answers.

Brattle compared a planned offshore grid to previous renewable-facilitating transmission projects, such as Texas' Competitive Renewable Energy Zones and MISO's multi-value projects. "New England could adopt a similar approach to planning transmission infrastructure to support offshore wind," it said. ■

ISO-NE News

NEPOOL Markets Committee Briefs

IMM: Winter Wholesale Costs down 32%

ISO-NE's winter wholesale market costs totaled $1.8 billion, a 32% decrease from the previous winter because of lower energy and capacity costs, the RTO's *Internal Market Monitor said in its quarterly markets report* released last week.

"The headline for winter 2020 is that it was a very mild winter, with low-priced gas and low load levels," IMM economist Donal O'Sullivan told the New England Power Pool Markets Committee on May 12.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

Average day-ahead and real-time Hub LMPs were $30.32 and $29.97/MWh, respectively, with the lower prices resulting from three primary factors, O'Sullivan said.

"Firstly, we had milder temperatures and an absence of very cold periods, which we like to call cold snaps, such as the region experienced in 2018. Secondly, we had low average natural gas prices, which at $3.40/MMBtu was down 41% from the prior winter's price," he said.

The low gas prices stemmed from declines at the supply basins, where year-on-year production increases outstripped demand increases, he said.

"And finally, downward pressure on energy prices also came from increased energy efficiency and additional behind-the-meter solar generation," O'Sullivan said.

On the capacity side of wholesale costs, payments of about $751 million were also down 24%, a $242 million drop from a year earlier, he said.

Winter 2020 was the third quarter of the Forward Capacity Auction 10 commitment period, with clearing prices of $7.03/kW-month for Rest-of-System, compared with an FCA 9 price of $9.55/kW-month.

Gross real-time reserve payments totaled $1.8 million, a 40% decrease from the same period a year ago, with 97% of those payments going for the 10-minute spinning reserve (TMSR).

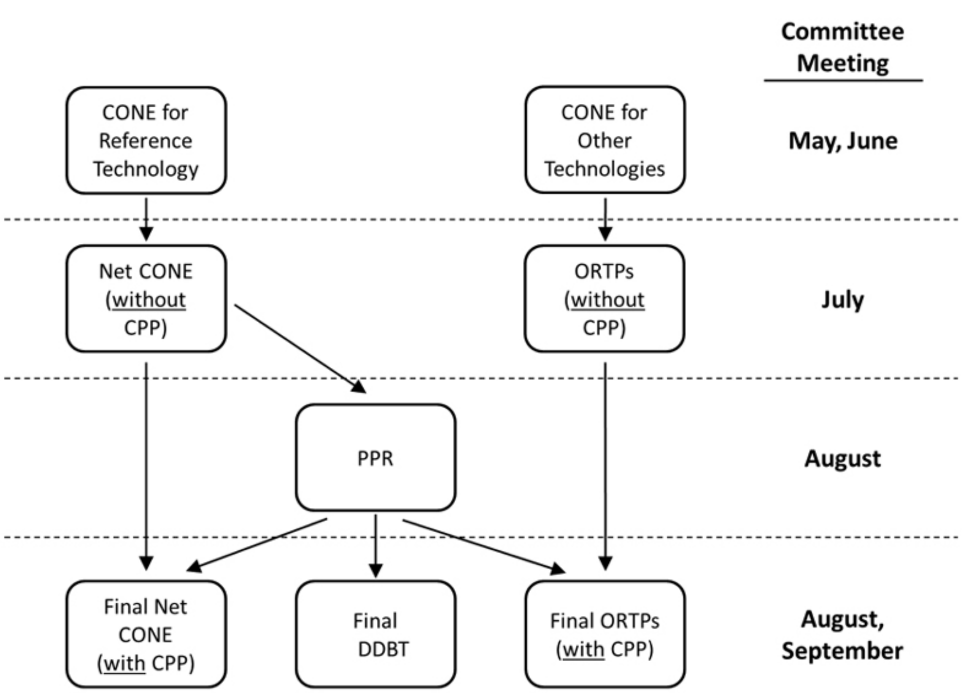
"This winter, there were 394 hours of non-zero reserve pricing, compared to 297 hours last winter. Despite there being more hours, payments were lower, with the average TMSR price of $7.56/MWh down from $16.31/MWh last winter," he said.

There were just 35 minutes of non-zero 10-minute non-spinning reserve (TMNSR) this winter and no instances of 30-minute operating reserve (TMOR) pricing during the season, he said.

"This is similar to previous winters where there were very few or zero hours of TMOR and/or TMNSR pricing," O'Sullivan said.

Energy market opportunity costs (EMOC) were $0/MWh during the winter, a feature implemented last year in reference levels in order to let the market preserve limited oil inventories for times when gas supply is low during extreme cold weather, he said.

For this winter, the EMOC values were updated prior to the real-time market opening to reflect the latest fuel prices, and the brief periods of cold weather allowed sufficient gas supply to ensure that EMOCs never rose above zero for any hour and had no impact on energy prices, he said.



Interdependencies between the various FCM parameters dictate the order in which the parameters are calculated. | *ISO-NE*

CASPR the Ghost

ISO-NE's Competitive Auctions with Sponsored Policy Resources (CASPR) substitution auction did not proceed this year despite 14 existing resources with a combined capacity of 445 MW having elected to participate.

The CASPR initiative for the FCAs was implemented two years ago to prevent consumers from paying twice for the same capacity through both the Forward Capacity Market and subsidies for state-mandated new supply resources. The initiative is also intended to reduce the possibility that capacity prices will be depressed below competitive levels by large quantities of unmitigated new subsidized resources entering the market.

In FCA 14 in February, while there were 292 MW of supply seeking to acquire capacity supply obligations (CSOs), there was no demand because the existing capacity resources either exited the auction without a capacity obligation or the RTO deemed them ineligible because their test price was greater than the FCA clearing price, O'Sullivan said. (See *ISO-NE Capacity Prices Hit Record Low*.)

"I think the design of this [CASPR] does need to be re-evaluated as to whether as designed it can actually achieve the goals it was meant to achieve," said Abigail Krich, president of Boreas Renewables. "Just because the region is long on capacity doesn't mean that it's not appropriate to have an organized way for resources that are trying to exit the market to trade their CSOs to resources that are trying to come in."

ISO-NE News

Recalculating Net CONE for FCA 16

Market development analyst Deborah Cooke led discussion of the RTO's proposal for *updating* the cost of new entry (CONE) and net CONE calculations, and recalculating existing and establishing new offer review trigger prices (ORTPs) using updated data for FCA 16, to be held in 2022 to cover the 2025/26 capacity commitment period.

CONE estimates the cost to build a new resource in New England, while net CONE indicates the net revenue needed by the resource to be economically viable. ORTPs are low-end estimates of net CONE for specific — and less common — technologies.

The RTO plans to work with stakeholders to review and estimate the impacts of two recently proposed market changes on the FCM parameters — the sunset of the Forward Reserve Market in 2025 and the Energy Security Improvements (ESI) filed with FERC in April.

The most recent recalculation was performed in 2016 for FCA 12. Historically, values are updated triennially, but the scheduled review was deferred one year to 2020 to allow for concurrent updates of two new related FCM parameters: dynamic delist bid threshold and performance payment rate, and the inclusion of estimated ESI revenues.

ISO-NE's *plan* for sunsetting the Forward Reserve Market in 2025, presented earlier in the meeting, calls for a vote in July, so the RTO will bring related values to the committee in June.

The RTO proposes to file any calculation changes with FERC by Dec. 1.

ESI Timing

ESI would allow the RTO to procure energy call options for three new day-ahead ancillary service products to improve the region's energy security, and option awards would be co-optimized with all energy supply offers and demand bids in the day-ahead market. (See *ISO-NE Sending 2 Energy Security Plans to FERC*.)

A FERC order on the ESI filing is expected by Nov. 1. One reason for a Dec. 1 filing is that the net CONE value is used early in the process for FCA 16, during the retirement and delisting window, and that window usually opens and closes near the beginning of March.

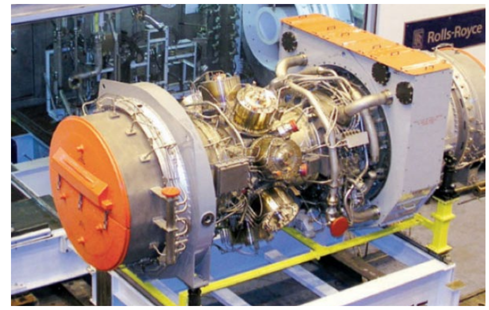
The RTO is estimating ESI revenues, given that the filing has two different proposals, one from the RTO and one from NEPOOL, and given the possibility that the commission might order some third way or a blend of the two.

Regarding new technologies such as continuous storage facilities, the RTO is modeling three new technology types for potential ORTPs: standalone batteries, co-located facilities with solar PV and offshore wind, according to the presentation.

Interdependencies between the various FCM parameters dictate the order in which they are calculated, and a *memo* from Mark Karl, ISO-NE vice president for market development, provided more detailed information on the various parameters and their interdependencies.

Concentric Energy Advisors Analysis

Engaged by the RTO to support the updates, Concentric Energy Advisors' Danielle Powers,



A net CONE recalculation analysis by Concentric Energy Advisors found that simple cycle gas turbines like this one, as well as CC turbines, are resources most likely to meet established economic and performance criteria. | *Rolls-Royce/Siemens*

Meredith Stone and Keith Paul presented a preliminary *analysis* of the net CONE and ORTP recalculations. Their findings conclude that simple cycle and combined cycle gas turbines are primary candidates for CONE calculation based on established criteria, and that other renewable, energy efficiency, demand response and gas-fired generation are primary candidates for ORTP calculation.

Powers said the application of the screening criteria to see whether CONE recalculation applies "should be consistent with the order given by FERC in 2017 [*ER17-795*], which is that net CONE should be high enough to attract new entry, but not so high as to introduce unnecessary costs."

Paul addressed the various technologies, including biomass, which are considered a niche area because there are few such facilities expected to be constructed or entering the interconnection queue in the near future.

Biomass facilities are typically smaller units with dedicated supply chains and tend to be either site-specific or regionally specific. For example, a unit in one state actually has a supply chain that covers the entire New England region and somewhat beyond in order to supply adequate wood to the facility.

Concentric's analysis found that paper mill combined heat and power facilities would not be a good application for a CONE or an ORTP calculation because of the variability of the energy output.

Concentric will continue its evaluation and analysis of technologies for CONE and ORTP calculations. In addition, the analysts will bring back to the committee in June preliminary technology costs for the calculations, determination of ORTP technologies and indicative FRM revenue-offset component values. ■

— Michael Kuser

Lower energy prices drove a 32% decrease in winter 2020 wholesale costs in New England compared to winter 2019. | *ISO-NE*

ISO-NE/NYISO/PJM IPSAC Briefs

PJM on Friday hosted an Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting to provide input for the development of the Northeast Coordinated System Plan (NCSP), which outlines planning activities conducted jointly by ISO-NE, NYISO and PJM.

Nebiat Tesfa, a PJM transmission planning engineer, said the group will continue coordinating studies across the grid operators' seams and issue the next NCSP by spring 2022.

PJM Tx Planning

Tesfa presented *updates* on PJM's planning processes and Regional Transmission Expansion Plan (RTEP).

She noted FirstEnergy Solutions' March announcement that it would withdraw its deactivation of the 1,872-MW Beaver Valley nuclear plant in Shippingport, Pa., citing Pennsylvania's efforts to join the Regional Greenhouse Gas Initiative (RGGI). (See *Beaver Valley Nuclear Plant to Stay Open*.) The company had filed a deactivation notice for the plant in March 2018, targeting a 2021 retirement.

"As a result, there are several baseline upgrades identified," Tesfa said. "Beaver Valley only recently announced the withdrawal of their deactivation request, and as a result, PJM is evaluating the impacts of the reinstatement of those generators, and we'll provide the results in the future meetings."

PJM is working to determine which transmission upgrades it can cancel in response FirstEnergy Solutions' reversal, she said.

ISO-NE Tx Planning

Brent Oberlin, ISO-NE director of transmission planning, presented *updates* on the RTO's transmission planning evaluations of the New England system.

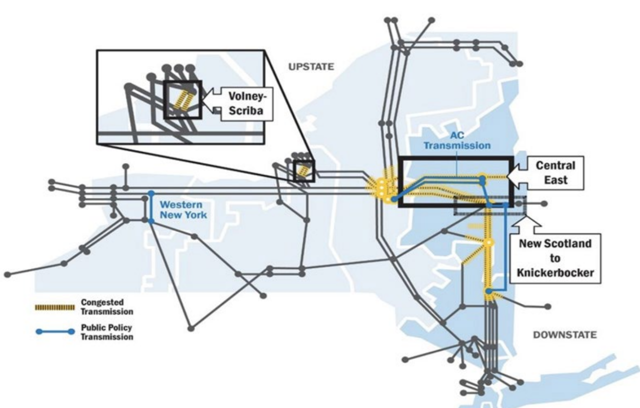
Oberlin highlighted Tariff changes to enhance the competitive transmission solicitation process, which FERC approved in December, including:

- creation of the Selected Qualified Transmission Project Sponsor Agreement (SQTPSA) to help determine the design and build of a new transmission project;
- improvements to Attachment K to the Open Access Transmission Tariff; and
- modifications to Schedule 12C of the Tariff to establish a new baseline for consideration of localized costs.

ISO-NE has completed a number of transmission planning studies, driven by the upcoming retirement of the Mystic generators in Connecticut, he said.

The RTO's competitive transmission solicitation for Boston garnered 36 proposals from eight qualified parties by the March 4 deadline, Oberlin said. The RTO is confident that some proposals in the phase one study process are going to be available for New England ahead of the June 1, 2024, retirement date for Mystic 8 and 9. (See "Faster Boston RFP," *NEPOOL Participants Committee Briefs: May 7, 2020*.)

ISO-NE received two submittals this year on the region's public policy transmission planning process, one from National Grid and the other from the Episcopal Diocese of Rhode Island, each of whom identified public policy requirements or other actions that, in their view, drive transmission needs, he said.



NYISO Congestion Assessment and Resource Integration Study (CARIS) phase I congestion groupings | *NYISO*

"All that information was forwarded to the New England States Committee on Electricity (NESCOE), and the way that works is they have the option of providing a response to the ISO ... and they can also supplement that information," Oberlin said.

NESCOE responded that it does not think ISO-NE should be studying any public policy transmission upgrades for this cycle, he said.

"We did add two new projects, which were to address the time-sensitive needs in Boston," Oberlin said.

Thirty-four new projects were added to the asset condition list, the lion's share of which were for replacing aging infrastructure, such as wooden poles damaged by woodpecker holes, he said.

NYISO Tx Planning

Philip Chorazy, NYISO senior engineer for public policy and interregional planning, presented *updates* on the ISO's Comprehensive System Planning Process (*CSPP*).

The 2020 Reliability Needs Assessment (RNA) will incorporate impacts of a new peaker rule into its base case reliability analysis, Chorazy said. The New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxide emissions from simple cycle combustion turbines, or peaking units, he said. The new regulations go into effect May 1, 2023, with initial rate limits of 100 parts per million on a dry volume basis, corrected to 15% oxygen. (See *NY DEC Kicks off Peaker Emissions Limits Hearings*.)

The RNA also will include a scenario evaluating the impacts of 70% of energy produced from renewable resources by 2030 for both transmission security and resource adequacy, with the first pass of RNA results to be presented next month, Chorazy said. New York's Climate Leadership and Community Protection Act (*A8429*) signed into law last July calls for 70% of the state's electricity to come from renewable energy resources by 2030, doubles the distributed solar generation target to 6 GW by 2025 and nearly quadruples the previous offshore wind energy target to 9 GW by 2035.

Chorazy also explained that the ISO's vvCongestion Assessment and Resource Integration Study (CARIS), which determines the top three congested locations in the New York Control Area and is intended to develop generic solutions for transmission, generation, demand response and energy efficiency. The 2019 CARIS Phase 1 draft *report* was presented at the ISO's Electric System Planning Working Group in April, with a final draft scheduled for July, pending Board of Directors approval.

NYISO will initiate the 2020/21 Public Policy Transmission Planning Process cycle in August by issuing a solicitation for proposed transmission needs driven by public policy requirements, Chorazy said. ■

— Michael Kuser

MISO News

MISO Floats Ideas on MTEP, Interconnection Coupling

By Amanda Durish Cook

MISO staff last week floated initial ideas on how the RTO could better synchronize the separate studies supporting its annual transmission planning and generator interconnection queue processes.

The RTO took up the issue after multiple renewable developers complained that their generation projects were unfairly being required to finance multimillion-dollar network interconnection upgrades that should rightly be handled in the transmission planning process. They argued MISO was relying on network upgrades to plan the system. (See *MISO Begins Bid to Merge Tx, Queue Planning*.)

During a Planning Advisory Committee conference call Wednesday, MISO North Region Economic Planning Manager Neil Shah said one idea would adjust the Transmission Expansion Plan (MTEP) model development timeline to allow for more coordination, analysis and stakeholder input.

Shah said MISO could reserve a window of time in the MTEP cycle to review transmission needs found across multiple planning processes, including reliability and economic benefits, and in interconnection queue studies. From there, the RTO could identify "focus areas with common issues" or transmission needs in "electrical proximity for further investigation and cost-effective solution development," he said.

MISO would have to decide how to select project needs unearthed in interconnection studies for testing for wider economic benefits under MTEP, Shah said. The RTO might settle on testing all new 230- or 345-kV upgrades that emerge from the first phase of the queue's three-part definitive planning phase, he said.

Shah added that MISO may need to instate a timing cutoff for upgrades identified in the interconnection queue to be evaluated as potential market efficiency projects. An early December cutoff makes sense, he said, because that falls close to the time that MISO opens the window for economic project submissions for the next year's MTEP cycle. He said a cutoff would ensure that interconnection upgrades are evaluated on a "fresh set of models and assumptions" from the latest MTEP cycle. He said MISO would accept other stakeholder ideas through May 28.

"These are some initial ideas. Definitely we'd like to hear from stakeholders for more ideas to explore," he said.

Stakeholders on a Planning Subcommittee conference call Thursday asked MISO to provide a spreadsheet of its modeling and assumptions across all planning processes so they could more easily detect inconsistencies that contribute to apparent discrepancies in transmission needs. MISO has also been asking stakeholders what changes it could make to methodologies and assumptions across separate planning studies to achieve more comparable treatment of transmission projects.

MISO Senior Manager of Expansion Planning Edin Habibovic said such a list runs the risk of being too long and confusing. Director of Planning Jeff Webb said the RTO "might try to hone in on the salient points."

Neil Shah, MISO | © *RTO Insider*

Clean Grid Alliance's Rhonda Peters said MISO has been seeing more 345-kV upgrades found in generator interconnection studies assigned to interconnection customers. She said the problem may lie in dramatically different contingency mitigation requirements in local planning criteria between different transmission owners. She asked for a review of TOs' local planning criteria.

Webb said MISO would likely arrive at "negotiated reasons" as to why the different planning processes can't be treated exactly the same.

MISO *said* all of its study processes — reliability and economic planning, transmission service requests, generation interconnection, generation deliverability and generation retirements — have "a uniquely defined purpose." ■

MISO News

MISO Targets Swifter Queue Processing

By Amanda Durish Cook

MISO is examining additional measures to shave the time its customers spend in the generation interconnection queue, this time focusing on the definitive planning phase (DPP) and negotiations on interconnection agreements.

The effort follows on FERC's December approval of a Tariff provision intended to help expedite the queue through more stringent site control requirements. (See *MISO OK'd to Require Site Control in Queue*.)

MISO now says its goal is to cut the time it takes to clear generation interconnection agreement (GIA) negotiations and the queue's *three-part* DPP, where the RTO performs interconnection studies.

Currently, the DPP process alone takes about a year. Combined with the agreement negotiations, the timeline shoots up to about 505 days. MISO aims to have both processes take a year total.

"Three hundred sixty-five days is the goal, and we want to strive for efficiencies wherever possible," interconnection engineer Cody Doll told stakeholders during a Interconnection Process Working Group conference call May 12. "Basically, we need to find a way to cut out 140 days from phase one to the end of negotiations."

MISO's interconnection queue *contains* 434 projects totaling 67.4 GW. It takes one project about three years to complete the queue.

Doll said if the process could be shortened to a year, it would help further MISO's goal of aligning the separate planning processes for its interconnection queue and annual Transmission Expansion Plan. (See *MISO Begins Bid to Merge Tx, Queue Planning*.)

"This is basically a companion to that effort ongoing in other MISO forums," Doll said.

MISO could crop about 60 days from phase one, Doll said, by getting a head start on its study models prior to the start of the DPP. He also said it could get a jump on developing mitigation plans by inputting in advance of the DPP some results from the screening analyses interconnection customers undergo before entering the queue. It could also probably devote less time to mitigation development, where the RTO recommends solutions to grid constraints, he said.

"The most projects drop out in phase one. It's just the nature of the beast, so it might be unnecessary to have as many back-and-forths in phase one because it's probably going to change," Doll said. "Phase two and three are already pretty lean. I don't think there's really any fat to trim in phase two."

In fact, he said, phase two has such an aggressive timeline that he recommends MISO add about 10 days to the existing 45-day timeline it gives itself to conduct system impact studies.

For phase three, Doll said MISO could begin using "engineering judgement" to begin some network upgrade facility studies immediately after the system impact study is complete and the project owner decides whether to stay in the queue. The current queue process prescribes a 40-day wait time between the owner's decision point and the start of an upgrade study.

But Doll said MISO could prune the most time from the existing 150-day timeline for GIA negotiations. He said it envisions the process could take about 44 days.

"A lot of GIA negotiations can occur concurrently with the network upgrade facility study," Doll explained.

He also said interconnection customers likely don't need 60 days to decide to execute a drafted GIA, and transmission owners don't need the allotted 30 days to decide the same.

Doll said that if everything goes according to plan, the new one-year process could potentially be introduced within two years. But he stressed that the plan so far is only a draft.

"We're going to make edits on this based on comments and rehash some things," Doll said. ■

| MISO

MISO News

Ind. Regulators Scrutinize Duke Self-commitments

By Amanda Durish Cook

Indiana regulators are collecting information from both sides of the argument over whether Duke Energy is prudently handling the self-commitments of its coal units in the state.

The Indiana Utility Regulatory Commission opened a docket in March to investigate Duke's self-scheduling practices after the company *applied* to increase its fuel adjustment charge, the amount billed to ratepayers based on fluctuating fuel prices. The IURC has scheduled a Sept. 21 hearing in the matter (*38707*).

The Sierra Club and Citizens Action Coalition of Indiana (CAC) have said there are "serious issues related to Duke's commitment decisions," pointing to the company's coal-fired Cayuga Generating Facility, Gibson Generating Station and Edwardsport Integrated Gasification Combined Cycle plant.

In testimony to the commission, Sierra Club attorney Kathryn Watson said the organization isn't sure if Duke is meeting its responsibility of providing electricity to retail customers at "the lowest fuel cost reasonably possible because those costs may include periods of unreasonable commitment for its Cayuga, Gibson and Edwardsport coal-burning plants into the MISO energy markets."

Jennifer Washburn, an attorney with CAC, also said Duke may be purchasing and storing "excessive amounts of coal" for some units.

Devi Glick, a senior associate at Synapse Energy Economics who testified on behalf of Sierra Club, said Duke's own analysis showed that Edwardsport could have earned $3 million if it ran on natural gas alone, compared with the $3.1 million in losses the company had projected based on the plant running on a synthetic gas-and-coal combination from Sept. 1 to Nov. 30, 2019.

Glick herself estimated that over the same three-month period, Duke's operational losses totaled $3.3 million at Edwardsport and $3.56 million at Cayuga.

"Duke should be electing to operate its units on a forward-looking basis only if it expects to make money, and the company should keep the units offline if they are projected to operate at a loss," Glick told the IURC. "While there are reasons why inflexible units with longer start-up and shutdown times, such as coal-fired units, may choose to self-commit, the company's process for deciding how and when to self-commit should result in reasonable decisions that do not bring or keep units online when they are projected to lose money over a multiday, weeklong or longer time horizon.

"Based on my review of the company's internal commitment-decision process … I see no indication that the company's internal processes are aligned with, or guaranteed to serve, the best interest of ratepayers," Glick added.

Shannon Fisk, managing attorney for the Earthjustice coal program who represents the CAC, said that while there potentially may be "a day here and there" where coal units operate uneconomically for other reasons, it shouldn't be nearly as often as occurs with Duke.

"They're incurring substantial losses running Edwardsport on coal, when the more logical approach is to shut the thing down, which would be cheaper for customers or, at worst, run it on gas," he told *RTO Insider*.

Duke: Must-run Statuses Justified

Duke spokesperson Angeline Protogere said the utility's goal is "always economic operation of our plants for customers."

"Each business day, we do an economic review of a number of factors as we make a decision for each unit," Protogere said in an email to *RTO Insider*.

In April 29 testimony, Duke Managing Director of Trading and Dispatch John Swez said the company commits its generating units "on an economic basis, except as required for unit testing, operational requirements or other infrequent reasons."

"Units are dispatched on an economic basis between their minimum and maximum capability when not required to run at a specific output as would be necessary for unit testing, an operational requirement or other reasons. Utilizing a commitment status offer of must-run in the MISO energy markets does not necessarily mean that a generating unit was not economically committed," Swez said.

He said must-run designations are sometimes necessary for facility testing, to ensure that a unit meets its minimum run-time to prevent wear or avoid damage from freezing temperatures. He also said the designation is needed because of the Indiana Municipal Power Agency's nearly 25% ownership interest in the 625-MW Gibson Unit 5 and the Cayuga station's arrangement that one unit remain at

Gibson Generating Station | *Duke Energy*

MISO News

or above 300 MW to supply steam to nearby industrial customer International Paper.

"Used properly, as we do, the use of a must-run offer reduces the overall cost to supply energy to our customers by reducing the additional costs and risk associated with the unnecessary and uneconomic cycling of longer lead-time generating units," Swez said.

But Fisk questioned "whether the proceeds from International Paper justify the costs to ratepayers" to keep the unit always switched on.

"The issue we've queued up in the commission is whether this is beneficial to customers. It's clear that sometimes they're dispatching the unit uneconomically," Fisk said.

Swez said the minimum run-time of a unit at the Gibson station is 72 hours, and a restart of Edwardsport's gasification systems can take up to 14 days. He also noted that MISO's day-ahead market "was never designed to forecast economic commitments beyond the next day."

Beyond that, Duke makes purchases of lower-cost energy from the MISO markets, Swez said, noting that the company last year purchased a little more than 30% of energy served to customers from the RTO. "The MISO energy markets are a resource that is used to the customers' advantage when power prices are below the cost of the company's generation cost," he said.

Protogere also noted that a unit under must-run designation in MISO is only required to be online for its minimum load.

"It's still MISO … that directs dispatch of a unit anywhere between a unit's minimum and maximum capability," she said. "If there is lower-cost power available, we make every attempt to turn down/off our units and purchase from the market. We manage our units as economically as possible for our customers. The ability to self-commit a generating unit is critical to avoid start-up expenses and operational risks incurred by cycling a unit offline and then back online during short periods."

Duke Vice President of Midwest Generation Cecil Gurganus also defended his company's practice of maintaining a coal pile at Edwardsport even though the plant can run on natural gas.

"We must acknowledge the reliability and resiliency value in fuel inventory maintained at coal plants, relative to natural gas. Even having contracted firm transportation agreements with natural gas suppliers is no guarantee of service when the commodity is

Edwardsport Integrated Gasification Combined Cycle plant | *Duke Energy*

curtailed," he said.

Gurganus said Edwardsport's fuel flexibility allows it to be available when other resources may not be. He also said the plant's permitting dictates it run on coal as a primary fuel source and natural gas as a secondary fuel.

But Fisk said Edwardsport is approved to run on either fuel.

"Duke has substantial over-inventories of coal," Fisk said, adding that utility-wide, it appears that Duke keeps about 60-plus days of inventory at units in addition to up to 1.4 million tons of coal in off-site storage. He said Duke should rethink coal-supply contracts and set aside any possible loyalties to keeping coal mines afloat. Duke officials pointed out in testimony that the plants use locally sourced Indiana coal.

"It should not be on Indiana ratepayers to keep a struggling coal mine is business," he said. "A more prudent approach would be to ask: How can we stop buying more coal?"

While Fisk said his organization has yet to evaluate a MISO multiday market, he argued it wouldn't change much about Duke's commitment behavior.

"The argument here isn't whether Duke on a daily basis is turning the unit on and off. The argument is: Duke has analysis over the coming weeks that the unit will be uneconomic, and it's committing it anyways. If their own projection is showing the unit won't make money, then it should be taken offline," he said.

MISO's Perspective

MISO itself continues to maintain that uneconomic coal must-run designations are uncommon.

The RTO said that from early 2017 to late 2019, self-committed coal units economically dispatched above their economic minimum level represented about 76% of its total coal-fired generation. MISO said it economically committed and dispatched another 12%.

"Added together, that means 88% of the region's coal-fired energy in the last three years was economically dispatched in some manner," MISO *said*.

But Fisk said that uneconomic commitments even 12% of the time represents "still quite a bit of money lost."

"Commissions should be carefully evaluating how to shrink that number," Fisk said.

MISO also points out that self-commitment is "used by all types of resources, not just coal." During March, coal represented just 2 out of the 12 TWh in self-committed and uneconomically dispatched generation, the RTO said.

It also reported that coal self-commitments are on the decline. In 2009, 64% of its total energy was from self-committed coal resources. By 2019, that share fell to 36%.

Despite the drop, MISO states Minnesota and Missouri have also opened similar investigations into utilities' coal plant self-scheduling.

Fisk acknowledged that coal self-commitments are on the decline even as they garner more attention. He said increasingly economic renewable resources have likely contributed to the emphasis on the issue.

"Certainly, the rise of renewables has contributed to lower-cost generation. The question is whether these utilities have properly adjusted to this new reality. It doesn't appear that Duke has attempted this transition," he said. ■

NYISO News

NYPSC Launches Grid Study, Extends Solar Funding

By Michael Kuser

The New York Public Service Commission on Thursday voted unanimously to undertake a study to identify distribution upgrades, local transmission upgrades and bulk transmission investments needed to meet the state's clean energy goals (*20-E-0197*).

"In my view, this is a timely, critical and thoughtful plan to start to modernize our grid … to meet our future needs, including the need to deliver the new clean energy called for by the state's agenda," PSC Chair John Rhodes said.

The study was mandated by a budget amendment passed last month that created a new siting agency for renewable energy projects. The New York State Energy Research and Development Authority will collaborate with the Department of Environmental Conservation and the Department of Public Service (DPS) to develop build-ready sites for renewable energy projects. (See *NY Renewable Supporters Push for New Siting Agency*.)

Under the new order, transmission investments that the commission determines must be "completed expeditiously" are referred to the New York Power Authority for development and construction. Other projects are to be selected for implementation through NYISO's public policy planning process.

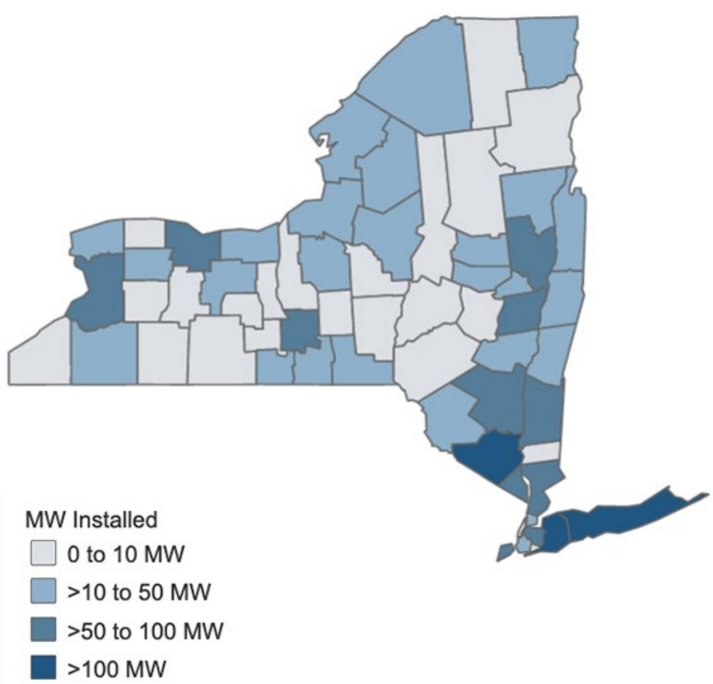
"I look most importantly to the New York ISO, who has been a leader in appropriate tactical studies as it relates to the grid, especially with the reliability and resiliency aspects, and the studies that they are currently undertaking," Commissioner Diane Burman said. "I do look to them as an important component of really critical evaluation and analysis that will be helpful."

Commissioner John Howard said that in "the process of turning legislative goals into policy ... we should be as cautious with other people's pocketbooks as possible. This rebuilding of the grid could be enormously expensive ... there's always the temptation to gold-plate the system."

Extended Run for NY-Sun

The commission also authorized an additional $573 million in funding to support the state's goal to procure 6 GW in distributed solar generation by 2025 and extend the NY-Sun program to 2025, as petitioned by NYSERDA in November (*19-E-0735*).

DPS staff determined that the state is on track to achieve the original goal of 3 GW by 2023, with more than 2,410 MW in service in New York and more than 1,200 MW currently in development.



NY statewide solar distribution showing 2,410 MW as of March 31, 2020 | *New York DPS*

The NY-Sun initiative was part of the Clean Energy Fund created by the commission in 2016, which established utility collections from ratepayers to support the overall $960 million funding requirement.

Burman was the sole vote against the program extension, as she was in last month's authorization for NYSERDA to solicit up to 2,500 MW of offshore wind energy this year. (See *NYPSC Greenlights 2,500-MW Offshore Wind RFP*.)

"I am really concerned about not only extending the program through 2025, which means the [ratepayer] collections continue, but also allocating additional funding — albeit it may be from reallocating uncommitted funds — and also then teeing up that we may be looking at new funding in a clean energy review," Burman said.

Rather than indicate in the order that the PSC expects NYSERDA to report back on the impacts of the COVID-19 pandemic on the distributed solar industry, she said the commission should be asking the agency to report on that now.

"Doing this now really concerns me because, as we've seen, even from last session, what we saw as a need to move quickly on something didn't necessarily mean that NYSERDA did," Burman said.

Following the commission's offshore authorization last month, NYSERDA said in a statement that it would not be rushing to put out a request for proposals amid the pandemic.

"My concern is that we have large-scale renewables solicitations on pause; we have the offshore wind solicitation on pause; we have a number of things that are on pause; and so the only thing not on pause is the movement of funding and the extension of programs that have ratepayer dollars attached to them," Burman said.

Commissioner Tracey Edwards joined the call for accountability.

"I'm concerned that what we have in here that benefits the low- and moderate-income communities actually happens," Edwards said.

She asked DPS staff to talk to NYSERDA about making the annual clean energy review into a quarterly review.

"I think it's just critical," she said. "Low-income communities get the brunt of environmental injustices right now, so if there are programs that are going to be put in place, we need to make sure that they are in fact working." ■

NYISO News

NYISO Explores Hybrid Interconnection Processes

By Michael Kuser

NYISO staff last week shared with stakeholders proposed interconnection processes for the various market participation options the ISO has floated as part of its effort to integrate hybrid storage resources (HSRs) into its energy and capacity markets.

Kanchan Upadhyay and Amanda Myott, energy and capacity market design specialists, respectively, *presented* the ISO's ideas to the Installed Capacity/Market Issues Working Group during a teleconference May 11.

The ISO is proposing three interconnection options for HSRs:

- Option 1 would allow HSRs to participate in the markets as distinct generators that share a point of interconnection (POI).
- Option 2 would enable participation through an aggregation model to allow resource components within the HSR that share a point of interconnection to bid as a single resource.
- Option 3 would recognize an HSR as a self-managed energy storage resource that receives some or all of its energy from a connected renewable generator. (See *NYISO Weighs Market Options for Hybrid Resources*.)

Upadhyay covered the potential energy resource interconnection service (ERIS) process for HSRs. She said that for any new or proposed facilities proposing to interconnect as a hybrid resource, all resources behind the same POI could be included in a single interconnection request.

Distinct resources participating under Option 1 would have a separate ERIS for each unit, limited to the minimum of the capability of the inverters or the capability of the respective units.

Under the current proposal, "the injection limit of the HSR project must be greater than or equal to the combined capability of all resources within the project," Upadhyay said. "The ISO is still evaluating a potential enhancement that would enable this option to accommodate HSR projects with an injection limit that is less than the combined capability of its component resources."

If existing market rules need to be modified, such changes will be developed for a potential vote at the Business Issues Committee by the end of the year, Upadhyay said.

ERIS Limits

While HSR units may be studied under a single request, they may require separate interconnection agreements because they are treated separately in the market, Upadhyay said.

Aggregate hybrid resources participating under Option 2 would have a single, combined ERIS limited to the minimum of the capability of the inverters or the total capability of the combined units.

Hybrid ESRs under Option 3 would have a single, combined ERIS limited to the minimum of the capability of the inverter or the capability of the storage component of the hybrid resource.

Stakeholders stressed the importance of allowing developers to specify lower interconnection limits than the total potential output of the inverters.

"There could very well be configurations under Option 2 that have multiple inverters, solar paired with storage in quite a few combinations," said Bill Acker, executive director of the New York Battery and Energy Storage Technology Consortium. "I think it was mentioned earlier that there was possibly some work on looking at how that might work with a collection of inverters. We would hope that it wouldn't necessarily have to be the sum of all the inverters; that you could actually set up a solution like that."

CRIS Limits

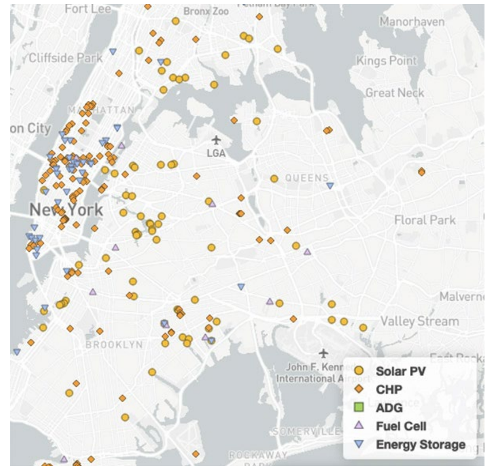
Myott led the discussion on capacity resource interconnection service (CRIS) awards for HSRs, whereby each distinct resource within an HSR may request CRIS individually up to the nameplate of the resource.

In response to a stakeholder question on the potential enhancement to Option 1 to allocate CRIS between the two resources, Myott said NYISO is investigating the topic in the event they are able to implement an inverter limit.

"We're thinking through all of the implications in terms of the application and how feasible implementing that would be, particularly in the short term [when] we're trying to make this option accessible for these types of resources," Myott said.

The ISO hopes to come back with more details soon but is not sure when, she said.

Aggregate hybrid resources under Option 2 may request CRIS up to the minimum of the



HSR CRIS Examples: Examples of capacity resource interconnection service (CRIS) for hybrid storage resources. | *NYISO*

inverter limit or nameplate of the components that comprise the HSR. Resources under Option 3 may request CRIS up to the minimum of the inverter limit or nameplate of the storage component, she said.

Myott closed by noting that the ISO is working on responses to various stakeholder questions, which will be addressed at a future working group. Topics include additional information about Northeast Power Coordinating Council reserve requirements; clarification on the "front-of-the-meter" definition; exploration of a possible thermal-plus-storage model; examples with numbers to understand how many megawatts can participate under each market (energy, regulation, reserves and capacity) under each proposed option; and clarification on which options the ISO will pursue.

Mitigation Review

Market Design Specialist Sarah Carkner presented an *update* on the ISO's comprehensive review of buyer-side mitigation (BSM), which is part of the "Grid in Transition" initiative. (See *N.Y. Looks at Grid Transition Modeling, Reliability*.)

FERC in February narrowed the resources exempt from *NYISO*'s BSM rules in southeastern New York, ordering the ISO to subject storage and demand response to a minimum offer floor in its capacity market. (See *FERC Narrows NYISO Mitigation Exemptions*.)

"We would like to move forward any concept as far as we can this year," Carkner said. "Ideally, we would like to get the market design complete on any additional concepts for this project." ■

NYISO News

FERC Partly OKs NYISO Mitigation Language

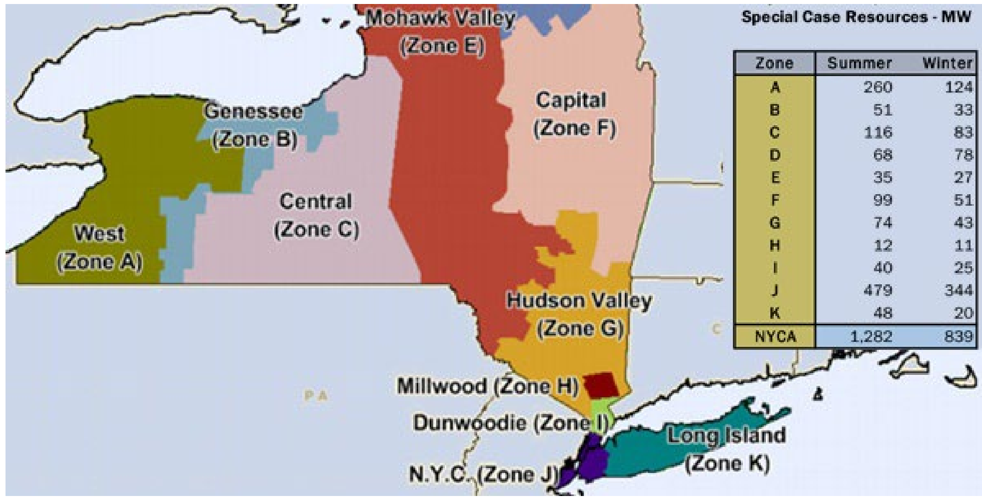
FERC last week partly accepted NYISO's March 12 compliance filing on buyer-side market power mitigation (BSM) rules, denying a waiver as unnecessary and rejecting the ISO's arguments on Tariff language.

The commission ordered the ISO to submit a compliance filing within 45 days of the May 12 order on the rules for special-case resources (SCRs), a type of demand response resource (*EL16-92-002, ER17-996*). (See *FERC Narrows NYISO Mitigation Exemptions*.)

The commission in February narrowed the resources exempt from NYISO's BSM rules in southeastern New York, ordering the ISO to subject storage and demand response to a minimum offer floor in its capacity market.

On April 1, NYISO's Market Monitoring Unit and the Independent Power Producers of New York (IPPNY) filed protests. The MMU asserted that the "State Program Language" exempting certain resources administered under New York programs should not be considered part of the currently effective Services Tariff, while IPPNY contended that the commission "fully addressed and expressly rejected" said language in a March 2015 order and reaffirmed that decision in its February order.

"Despite NYISO's claims to the contrary, the commission never accepted, and indeed expressly rejected, the State Program Language at issue," FERC said.



Zone	Summer	Winter
A	260	124
B	51	33
C	116	83
D	68	78
E	35	27
F	99	51
G	74	43
H	12	11
I	40	25
J	479	344
K	48	20
NYCA	1,282	839

FERC ruled in February that new special-case resources in southeastern New York are subject to NYISO's buyer-side mitigation rules. | *NYISO*

NYISO also requested in its filing a conditional waiver to authorize the ISO's past implementation of the February 2017 order from the period between that order — which established a blanket exemption for SCRs — and the February order that in part granted rehearing of the 2017 order.

"That waiver is unnecessary because in the February 2017 order, the commission directed NYISO to exempt SCRs from NYISO's buyer-side market power mitigation rules effective as of the date of that order," the commission ruled. ■

— Michael Kuser

PJM News

SATA Issue Charge Moves Forward in PJM

Will Determine Whether, How to Consider Storage in RTEP

By Michael Yoder

The PJM Planning Committee last week approved an initiative to develop rules for "if and how" storage should be considered in the Regional Transmission Expansion Plan (RTEP) process.

The storage as a transmission asset (SATA) *issue charge* was approved May 12 by an acclamation vote with one objection and no abstentions after some stakeholders expressed misgivings about the potential that storage could be a transmission asset at times and a market participant at others.

PJM is looking to develop "transparent rules" by the end of the year for how it would evaluate storage's performance and cost and whether it could be an alternative to traditional transmission reinforcements. Proponents say storage could be dispatched by the RTO to address thermal, voltage or stability violations or to relieve transmission constraints.

During a first read of the problem statement and issue charge April 14, some PC members raised issues with PJM's proposal, questioning its scope and timing. (See *Stakeholders not Sold on PJM SATA Plan*.)

During last week's second read, PJM's Jeff Goldberg said staff made several changes to reflect stakeholder and internal feedback. "While PJM's approach to SATA hasn't changed, some sections were entirely rewritten to incorporate comments and give clarity to PJM's goal," Goldberg said.

To address stakeholders' concerns that the concept of SATA is an unsettled issue, staff added a paragraph to the *problem statement* citing two FERC decisions regarding proposed SATA systems in CAISO. The first was a 2010 decision approving transmission incentives for a project by Western Grid Development (*EL10-19*); the second was a 2008 denial for a project proposed by Nevada Hydro (*ER06-278*).

Wording was also added to the problem statement to clarify that PJM has not decided "whether or not storage assets should be included" in the RTEP.

Goldberg said Phase 1 of the process will be focused on identifying gaps in existing transmission planning rules for evaluating storage. Because PJM is the NERC-registered transmission planner and must be comply with reliability standards, Phase 1 also will identify any operations impacts that need to be addressed in Phase 2.

Issues regarding SATA implementation, such as telemetry requirements, are out of scope for Phase 1.

The RTO acknowledged the potential for SATA's dual use.

"PJM recognizes that the evaluation of the cost-effectiveness of a given storage solution to a transmission reliability or market efficiency need could be impacted by the question of whether and how the unit would participate in the market," the issue charge says. "Nevertheless, this issue is derivative of the primary question, to be answered in this Phase I, as to the feasibility of evaluat[ing] energy storage purely as a transmission asset."

"We're taking a measured approach," Goldberg said.

Carl Johnson of the PJM Public Power Coalition said he appreciated the "significant changes" the RTO put into the problem statement and issue charge to address stakeholder concerns.

"I'm not enthusiastic about having this conversation because I'm not enthusiastic about the possibility of looking at dual use," Johnson said. "But I understand where PJM is, which you may see these things approved somewhere on the system through a process that isn't the RTEP and you'll have to figure out how to incorporate those."

John Brodbeck of EDP Renewables also said he wasn't enthusiastic about bringing up the issue of SATA. He said he would have liked more clarity on how projects would be paid for and who could bid on a project.

"I'd like to make sure that there's an Order 1000 process; that if we're going to do storage as a transmission asset, we make sure that in order to build this, things are made available to everyone in the marketplace," Brodbeck said.

PC Chair Dave Souder said making sure projects were open to competition would be part of the interest identification in Phase 1, so it wouldn't be out of scope.

The committee will hold monthly special sessions beginning around June to work on the initiative. Proposed changes to manuals or other governing documents are expected to be completed by the end of the year. ■

Primus Power energy pods | *Primus Power*

PJM News

TOs Back PJM End-of-life Proposal

Both Sides Cry Foul on PJM Staff

Continued from page 1

The maneuvers by the TOs and LS Power mean that only two proposals will be brought to sector-weighted votes at the May 28 MRC meeting.

PJM officials said at the April 30 MRC meeting that the package with the most support that meets the two-thirds threshold will be brought back to special meetings to draft governing document language. The package receiving the greatest support would become the main motion for a vote of the Members Committee on June 18.

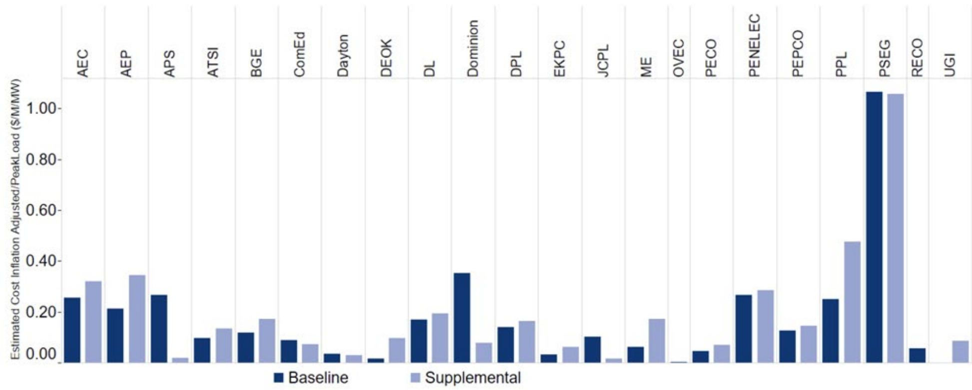
On Friday, however, PJM Director of Stakeholder Affairs Dave Anders said it was unclear the May 28 vote on the joint stakeholder proposal would include their proposed Operating Agreement language. He said the procedure would be clarified in the agenda for the meeting.

Under the Consolidated Transmission Owners Agreement (CTOA), the TOs are required to provide stakeholders 30 days to comment before filing proposed Tariff changes. (Comments may be submitted to *Comments_for_Transmission_Owners@pjm.com*.)

The June 8 comment deadline gives the TOs more than a week to file their proposal with FERC before the MC votes.

"This [Section] 205 notification changes the game fairly significantly relating to the timing of voting on OA changes," said Sharon Segner of LS Power. "Time is of the essence."

Both the stakeholder and PJM proposals would require TOs to share how they make EOL determinations and potentially open at least some replacement projects to competition under the Regional Transmission Expansion Plan (RTEP).



Baseline and supplemental projects since 2005 (adjusted by peak load) | *PJM*

The joint stakeholder *proposal* would require TOs to notify PJM and stakeholders of any facility nearing the end of its life at least six years before its retirement date so that the project could be included in five-year planning models and opened to competitive bidding. It would also modify the supplemental project definition to exclude EOL projects, which would become a new category of regionally planned projects.

LS Power's proposal was identical except for requiring at least eight years' notice for facilities of 230 kV and above. Segner said Friday that her company decided to address the issue in future manual changes because the joint stakeholders' OA changes referred to "at least six years'" notice.

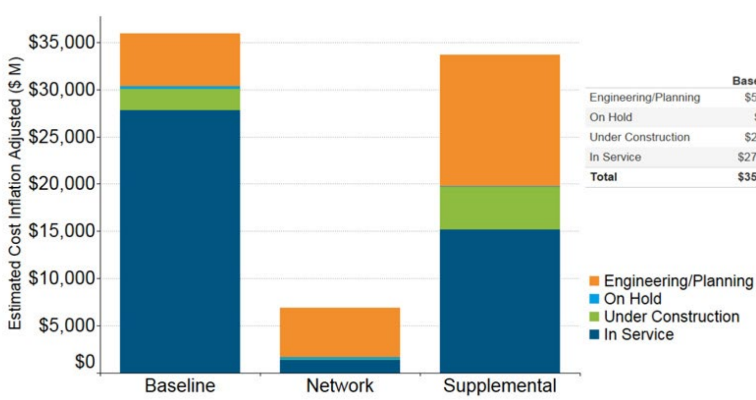
PJM's *package* requires TOs to have a formal program for EOL determinations and to identify potential EOL projects five years in advance. Projects that "overlap" with RTEP violations would be included in a competitive window seeking regional solutions.

The RTO said it would implement its plan through *changes* to Manual 14B: PJM Region Transmission Planning Process. The stakeholders questioned whether it would have authority to enforce the new rules if they were in the manual alone and have proposed *changes* to the OA, which they outlined during the nearly three-and-a-half-hour meeting Friday.

The TOs' representative, Chad Heitmeyer, director of RTO policy for American Electric Power, said their proposed changes to Tariff Attachment M-3 go beyond FERC requirements to provide increased transparency on "certain asset management projects, including EOL projects." The TOs said the revision would continue to "honor [TOs'] responsibility over end-of-useful-life replacement projects."

He said the only significant difference between the TOs' proposal and PJM's is the TOs' belief that the new rules require changes to Tariff Attachment M-3. "The Tariff is the most appropriate governing document to effectuate the delineation of responsibilities between PJM and the PJM TOs," Heitmeyer said.

However, the TOs also said that under their proposal, the nonbinding five-year forecast of EOL candidates would be confidential and shared with PJM only. The stakeholders want the list to be made public. Dave Souder, senior director of system planning, said at the April



	Baseline	Network	Supplemental
Engineering/Planning	$5,635	$5,221	$13,952
On Hold	$253	$217	$70
Under Construction	$2,244	$29	$4,499
In Service	$27,811	$1,411	$15,160
Total	**$35,944**	**$6,878**	**$33,680**

Project status as of Dec. 31, 2019 | *PJM*

PJM News

30 MRC meeting that PJM hadn't decided whether the list would be made public or not.

On Friday, Souder said PJM would determine which EOL projects "overlap" with RTEP violations and would be included in a competitive window seeking regional solutions. EOL projects for which PJM did not find overlaps would not be disclosed, Souder said.

ODEC's Mark Ringhausen said PJM's approach represented a "complete lack of transparency."

The TOs have been under increasing pressure from both stakeholders and FERC as spending on EOL and other supplemental projects controlled by the TOs has overtaken baseline upgrades planned by PJM. FERC opened Section 206 investigations of PJM, ISO-NE and SPP in October, saying the TOs appeared to be thwarting Order 1000's intent to open transmission projects to competition by abusing the "immediate need" exemption for reliability projects. (See *RTOs, TOs Defend Competition Exemptions*.)

Last week, the joint stakeholders sent a *letter* to the PJM Board of Managers highlighting the "the mounting evidence that the majority of transmission planning in the PJM footprint is not occurring on a regional basis." The letter came as PJM reported that TOs' supplemental projects totaled almost $3.4 billion in 2019, more than double the less than $1.5 billion in regionally planned baseline projects. It marked the fifth year out of the last six in which supplemental projects exceeded baseline projects. (See related story, *Stakeholders Urge PJM: Plan 'Grid of the Future'*.)

Segner said she was concerned by the potential Section 205 filing because it "essentially moved a number of [FERC] Form 715 projects potentially into the supplemental bucket" exempt from competition. Last August, FERC ordered PJM to open Form 715 transmission projects to competitive bidding, with regional cost-sharing for those projects involving high-voltage lines. (See *FERC Opens Local Tx Projects to Competition, Cost Sharing*.)

"I don't think PJM can file this because it violates the Operating Agreement," she said.

Attorney Don Kaplan, representing the TOs, said the Tariff changes were not intended to have any impact on handling of Form 715 projects.

Process Dispute

Friday's meeting opened with both load-side stakeholders and TO representatives criticizing PJM staff for mismanaging the agenda.

Load-side stakeholders accused staff of ignoring their requests to post the proposed OA language changes with meeting materials and include discussion of them on the agenda.

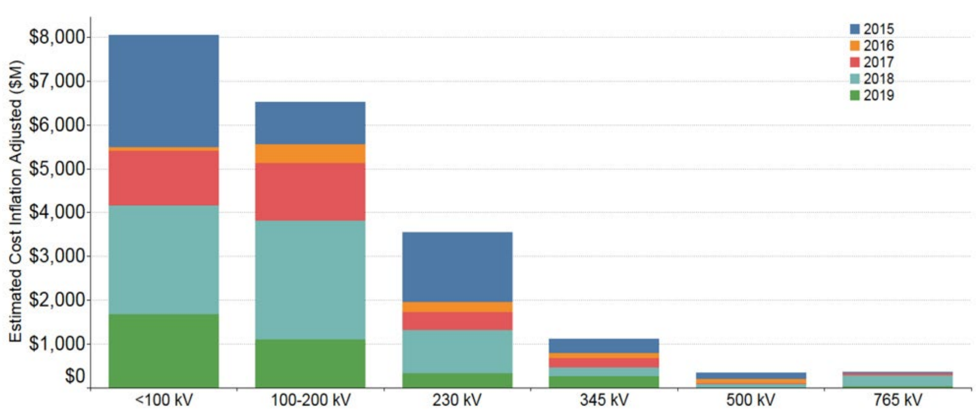
The OA language had been public since April 23, when it was posted for the April 30 MRC meeting. But it wasn't until Thursday — after emails from multiple stakeholders — that it was posted with the materials for Friday's meeting, said ODEC's Adrien Ford, a former PJM staffer.

PJM facilitator Jim Gluck, who chaired the meeting, said the failure to post the language earlier was an "administrative oversight."

Ford wasn't so sure. "There were multiple emails. That's a lot of flubs," Ford said. "This really feels like we're not being treated equitably."

"The intent is to treat all stakeholders equitably," Gluck said.

"The outcome is much different from the intent," AMP's Ed Tatum responded.



Supplemental projects by voltage (2015-2019) | *PJM*

After about 30 minutes of arguments, Gluck agreed to amend the agenda to provide time for the stakeholders' presentation.

That prompted a protest from PPL's Amber Thomas, who said stakeholders were not given notice that the OA language would be discussed during the meeting.

"There's a lot of confusion about how this agenda was developed," she said. "This all feels very messy and very confusing. … Some of you talked about [how] the stakeholder process is broken. This is another example."

"I want to acknowledge that this is getting very tense," responded PJM's Anders, who promised staff "will certainly do a debrief on this internally."

OA Page-turn

AMP General Counsel Lisa McAlister, who presented a page-turn of the proposed OA changes, said the stakeholders' goal is to "put end-of-life planning on a par with reliability planning."

Responding to questions about proposed revisions to the definition of supplemental projects, attorney Mike Engleman, representing LS Power, said, "To be frank, the intent was to not allow supplemental projects to be used to … prematurely replace facilities to avoid" the EOL notification requirement.

AEP's Heitmeyer *presented* the TOs' proposal. "After reviewing PJM's package, it was evident we were in alignment," he said.

The PJM and stakeholder packages were developed in a series of lengthy meetings since December.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said he was "frustrated" by the TOs' late introduction of their proposal and their threat to file it unilaterally with FERC.

"I would say this kind of ends the CBIR [consensus-based issue resolution] process at the Planning Committee," he said.

"I don't think the TOs consider what we've done here to be counter to the CBIR process," said Alex Stern of Public Service Electric and Gas. "All we're doing is facilitating what PJM has laid out."

Tatum pressed PJM officials for their reaction to the TOs' proposal, but Souder refused to take a position, saying only that the RTO is "very supportive of the stakeholder process." ■

PJM News

Stakeholders Urge PJM: Plan 'Grid of the Future'

By Rich Heidorn Jr.

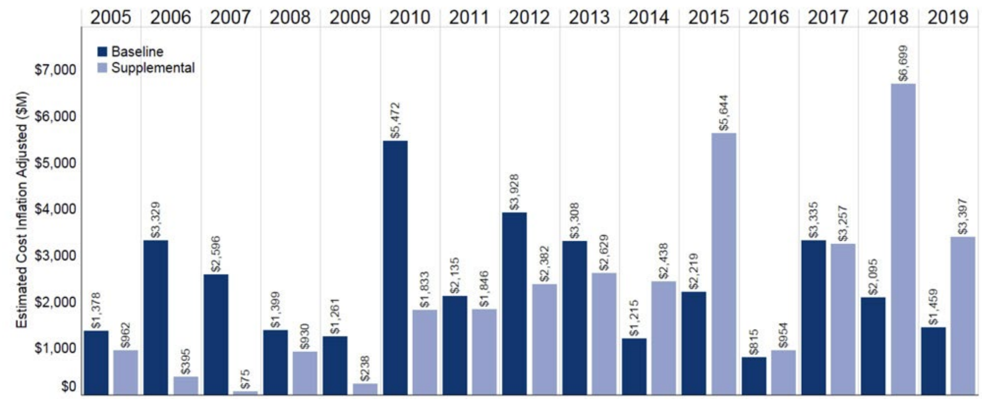
Transmission owners' supplemental projects totaled almost $3.4 billion in PJM in 2019, more than double the less than $1.5 billion in regionally planned baseline projects, the RTO told the Transmission Expansion Advisory Committee last week. It marked the fifth year out of the last six in which supplemental projects exceeded baseline projects.

Sharon Segner, LS Power | © *RTO Insider*

"Supplemental projects undermine the strength of PJM as a regional planner," LS Power's Sharon Segner responded after a *presentation* by PJM's Aaron Berner on May 12. "The question in our mind is: Is the right transmission being built?"

She was repeating a position that she and load-side stakeholders have made repeatedly in prior meetings — and that LS Power and dozens of other stakeholders made in a *letter* the same day to the PJM Board of Managers.

"Will the Grid of the Future be regionally or locally planned?" they asked. "We believe that the best way to reliably, cost effectively and holistically plan the Grid of the Future is through PJM's independent regional planning process."



Baseline and supplemental projects by year | *PJM*

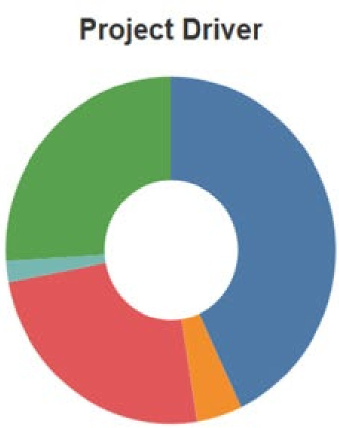
Signing the letter, in addition to LS Power, were American Municipal Power, Old Dominion Electric Cooperative, the PJM Industrial Customer Coalition and numerous municipal utilities and state public advocates.

The stakeholders noted that the largest component of the spending on supplemental projects in 2018 was that identified by TOs as necessary because of end-of-life (EOL) conditions. "The statistics for 2019 also show that the vast majority of projects were based on claims of EOL conditions and were not subject to regional planning," they said.

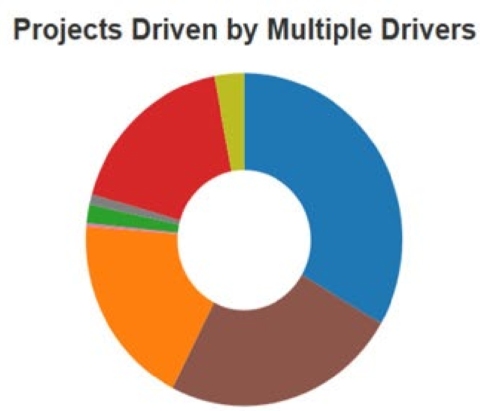
They called for Operating Agreement changes to make clear that PJM plans replacements for facilities identified by TOs as end-of-life, quoting from the board Reliability Committee's Oct. 4, 2019, *letter* that said, "PJM may be in the best position to determine the more cost-effective regional solution to replace a retired facility."

"The transmission system in PJM needs to be developed with an eye toward the future, rather than simply rebuilding the grid of the past," the stakeholders said. "We envision a future where PJM is able to combine drivers of transmission projects, namely public policy projects, with aging infrastructure replacement projects, to plan the Grid of the Future through a robust and transparent regional planning process."

The stakeholders sent the letter to help the



Equipment Material Condition, Performance and Risk	$1,461
Operational Flexibility and Efficiency	$151
Customer Service	$835
Other	$67
Multiple Drivers	$883
Infrastructure Resilience	$1
Total	$3,397



Equipment Material Condition, Performance and Risk / Customer Service	$295
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency	$212
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency / Customer Service	$166
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency / Infrastructure Resilience	$3
Infrastructure Resilience / Customer Service	$16
Operational Flexibility and Efficiency / Customer Service	$9
Operational Flexibility and Efficiency / Infrastructure Resilience	$155
Operational Flexibility and Efficiency / Infrastructure Resilience / Customer Service	$27
Total	$883

2019 supplemental project drivers | *PJM*

PJM News

board understand their proposals scheduled for a vote at the May 28 Market and Reliability Committee meeting to change the OA to authorize PJM to direct the most cost-effective solution after the TO provides an EOL notification.

Three EOL proposals were given first reads at the April 30 MRC meeting. The proposals — which would require TOs to share how they make EOL determinations and potentially open at least some replacement projects to competition under the Regional Transmission Expansion Plan — are the result of deliberations over six special MRC meetings since December. (See PJM End-of-life Tx Proposals Near Vote.)

In their letter, the stakeholders insisted their proposal "is consistent with" the Consolidated Transmission Owners Agreement — just one of the many points on which the TOs disagree with the stakeholders. The stakeholders also repeated their assertion that two FERC orders cited by TOs relating to "asset management" are irrelevant to their proposal.

"Our collective hope is that PJM follows the direction set forth by [CEO Manu] Asthana and refrain from advocating particular policies and instead listens to all stakeholders and perspectives and brings expertise to bear to help achieve the three priorities of reliability, planning and market function for the most efficient delivery of power to [PJM's] 65 million customers," they said, inviting "constructive feedback" from the board.

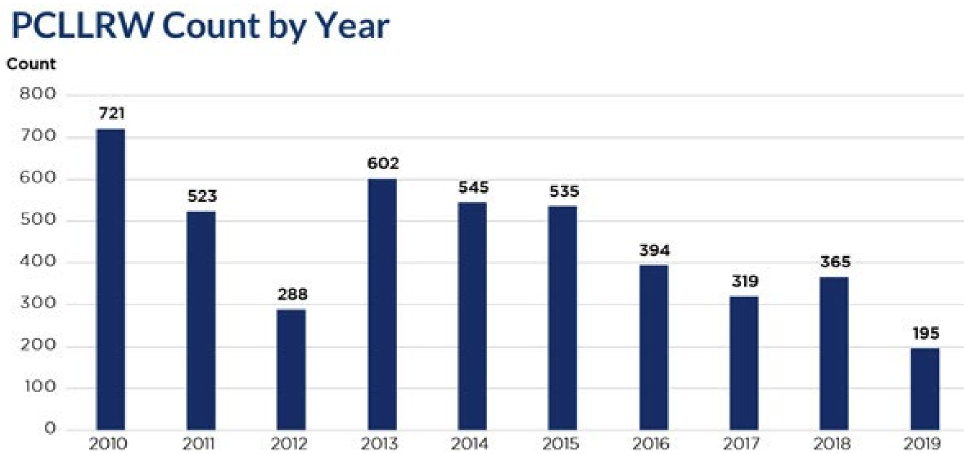
The TOs are likely to make their own case to the board. But at the TEAC meeting, it was left to Alex Stern of Public Service Electric and Gas to get in the last word on their behalf.

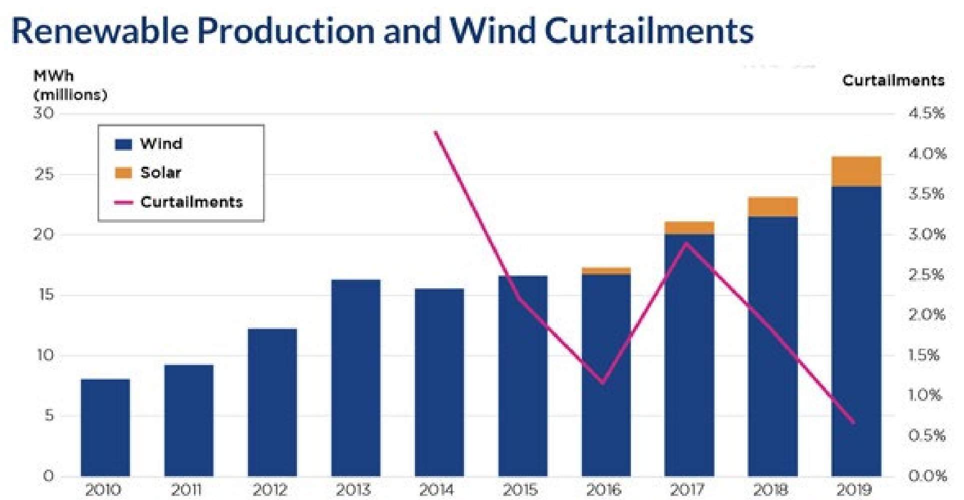
Alex Stern, PSE&G | © RTO Insider

"They're excellent sound bites, but they don't mesh with the project statistics [PJM] just showed," Stern said.

During his presentation, Berner introduced new graphs showing that post contingency local load relief warnings, wind curtailments and system congestion costs all have trended down in recent years.

"The data PJM presented in its Project Statistics review today demonstrates that PJM has been a strong regional planner," Stern added after the meeting. "Particularly in the midst of the current pandemic, the region is worried about a lot of things but, thus far, fortunately, cost-effective, reliable power has not been one of them." ■





Post contingency local load relief warnings (PCLLRW), wind curtailments and system congestion costs all have trended down in recent years, PJM says. | *PJM*

PJM News

PJM Announces $10M Resettlement in ComEd LDA

Ill. Wind Farm's Gain is Other LSEs' Loss

By Rich Heidorn Jr.

| E.ON

PJM will pay an Illinois wind farm at least $10 million under a FERC-ordered resettlement of incremental capacity transfer rights (ICTRs) to the Commonwealth Edison locational deliverability area (LDA), the RTO said Thursday.

On April 16, FERC ordered PJM to recalculate the ICTRs for Radford's Run Wind Farm, agreeing with facility owner E.ON Climate & Renewables N.A. that the analysis should have used the base case for the 2015 Base Residual Auction, entitling it to 279 MW of ICTRs (EL18-183). (See *PJM Ordered to Recalculate Wind Farm's Capacity Rights*.)

ICTRs — available to interconnection customers that are required to fund a transmission facility — are awarded based on how much the improvement increases the transmission import capability into an LDA. The rights are good for up to 30 years.

In 2018, the commission ordered a paper hearing after granting a complaint by Radford's Run, which said PJM unfairly denied ICTRs for funding an upgrade identified in its system impact study to mitigate a thermal overload on the 345-kV Loretto-Wilton Center line. The 306-MW wind farm in Macon County, Ill., began operations in 2018. The commission ordered the hearing to determine whether the upgrade increased the capacity emergency transfer limit of the ComEd LDA, entitling it to ICTRs.

The commission's April 16 order entitled Radford's to receive payments for the capacity auctions held in 2016-2018 for delivery years 2019/20, 2020/21 and 2021/22. It also required PJM to resettle payments for the ICTRs and to rebill affected load-serving entities for the nearly complete 2019/20 delivery year.

On Wednesday, PJM canceled a *presentation* on the resettlement that was scheduled for the Market Implementation Committee. The presentation said the annual economic value of the 279-MW ComEd LDA ICTR was almost $10 million for 2019/20, $1.04 million for the upcoming 2020/21 delivery year and $5.6 million for 2021/22, as of the first Incremental Auction, which is subject to change based on results of the second and third IAs.

The $10 million payment for the nearly completed 2019/20 delivery year will be clawed back from other LSEs in the ComEd LDA. PJM said the final zonal credit rate for the ComEd zone was reduced to $2.34/MW-day from the initial rate of $3.43/MW-day per megawatt of unforced capacity obligation, a 32% cut. The resettlement will be included in the May invoices PJM expects to issue on June 5.

For the 2020/21 delivery year, the rate was reduced to $0/MW-day from 12 cents/MW-day. ICTR holders only receive revenues if the LDA in question is constrained in subsequent capacity auctions. ■

IMM: PJM Energy Markets Remained Competitive in Q1

By Michael Yoder

PJM's first-quarter energy prices fell to their lowest level since the RTO was created in 1999, according to the Independent Market Monitor's first-quarter State of the Market *report* released Friday.

The Monitor cited lower fuel costs, mild winter conditions and a significant drop in energy use resulting from COVID-19 pandemic-related stay-at-home orders as contributing factors.

The report showed that real-time LMPs averaged $19.85/MWh during the quarter, down 34.2% from the same period in 2019. The Monitor found that 46.4% of the $10.31/MWh decrease was a direct result of lower fuel costs, specifically natural gas.

"Our analysis concludes that the results of the PJM energy market were competitive in the first three months of 2020," Monitor Joe Bowring said in a press release.

PJM load was down 6.8% cumulatively in the first quarter compared to the same time last year, the report said, and heating degree days fell 21.8%. Total energy uplift charges decreased by $12.1 million — or 62.6% — from $19.3 million in 2019 to $7.2 million in 2020.

Energy prices were set mostly by generating units operating at or near their short-run marginal costs, the report said, providing evidence of competitive behavior and market outcomes. Net revenues decreased for all generator unit types compared to 2019, the report said, including theoretical net revenue drops of 98% for a new coal unit, 34% for new nuclear plant, 32% for a new combustion turbine and 29% for a new combined cycle unit.

Meanwhile, the trend toward more natural gas-fired generation and less coal grew in the first quarter, with the share of gas increasing from 33.2% to 40% compared to a year earlier, while coal declined from 26.9% to 18% today.

Congestion costs decreased significantly compared to the same time last year, falling from $163.9 million in 2019 to $85.1 million in 2020.

Structural Change Recommendations

The Monitor added four new recommendations to its list, some dating back as far as 2009.

In the "Energy Market" section of the report, the Monitor recommended that that PJM clarify, modify and document its process for dispatching reserves and energy when security-constrained economic dispatch (SCED) indicates that supply is less than total demand, including forecasted load and reserve requirements. The suggested modifications from the report include a definition of a SCED process to economically convert reserves to energy, a process for the recall of energy from capacity resources and a determination of the minimum level of synchronized reserves that would trigger load shedding.

External balancing authority default interface pricing point assignments | *Monitoring Analytics*

"When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices, and those prices should be applied to the market interval for which RT SCED calculated the shortage," the report said. "There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices."

Debate over fast-start pricing has been ongoing among PJM and stakeholders for several years. (See *PJM IMM at Odd on 5-Minute Dispatch, Pricing Rules*.)

In the "Demand Response" section of the report, the Monitor recommended that all demand resources register as pre-emergency load response and that the *Emergency Load Response Program* be eliminated. The recommendation was listed as a high priority.

"Emergency and pre-emergency resources receive capacity revenue from the capacity market and also receive energy revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency or pre-emergency event," the report said. "The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in Reliability Pricing Model (RPM) auctions."

Finally, in the "Interchange Transactions" section, the IMM made two recommendations:

- Transactions sourcing in the Western Interconnection should be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The recommendation is a high priority.

The assignment of the Saskatchewan Power and Manitoba Hydro balancing authorities from the Northwest interface pricing point should be changed to the MISO interface pricing point, and the Northwest interface pricing point should be eliminated from the day-ahead and real-time energy markets. The recommendation is a high priority. ■

PJM PC/TEAC Briefs

Planning Committee

Market Efficiency Process Packages Move to MRC

Incumbent transmission owners in PJM won a victory last week as the Planning Committee endorsed creation of a new regional targeted market efficiency project (RTMEP) process that would be excluded from competition. The new process will involve backward-looking analysis to address persistent congestion not identified in the forward-looking planning model.

The PC endorsed a combined proposal by American Electric Power and FirstEnergy on the RTMEP process with 56% support. The AEP-FE package, which would exempt RTMEPs from competition, edged out PJM's proposal (55% support), which called for 30-day competitive windows to select the developer.

The two packages were otherwise identical. They would calculate benefits based on the average of the past two years of day-ahead and balancing congestion, adjusted for outage impacts. To be approved, a project would have to recover the project's capital cost within four years.

AEP-FE's proposal for the benefit calculation metric also was preferred, winning 54% to PJM's 52%. AEP and FE would employ a single-draw Monte Carlo simulation, with simulations for both Reliability Pricing Model and Regional Transmission Expansion Plan (RTEP) years. PJM proposed averaging Monte Carlo results and running them on RTEP, RTEP+3 and RTEP+6 years. Projects must have a capital cost under $20 million and be in service within three years.

The Independent Market Monitor's proposals on those two components each received less than 20% support.

PJM's proposed window for capacity drivers won 52%, besting the IMM's proposal with 25%. (AEP and FE did not offer an alternative window.) PJM proposed a 24-month cycle for energy drivers and a 12-month cycle for capacity.

AEP and FE said the interregional PJM-MISO TMEP planning process has produced six projects costing $120,000 to $6.7 million, none of which involved greenfield projects and each of which was assigned to incumbent TOs. Three involved line reconductoring; two required replacing or upgrading terminal equipment; and one was for reconfiguration of a ring bus. The companies said they expected that regional TMEPs would produce similar projects.

The PC's May 12 endorsement culminated 18 months of work the Market Efficiency Process Enhancement Task Force and sets up final votes at the Markets and Reliability Committee. Each issue in the package needed at least a 50% vote to move on to the MRC for a final sector-weighted vote.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, asked when manual language will be drafted for the AEP package to be voted on. PJM's Jack Thomas said manual language or government document language will be drafted for the first read at the June MRC meeting but could be pushed back to the July meeting depending on how long it takes to put together.

Changes Approved to CISO Issue Charge

The PC approved Exelon's revisions to the Critical Infrastructure Stakeholder Oversight issue charge over the objection of the original sponsor, the D.C. Office of the People's Counsel.

Exelon's *redline* of the issue charge that was originally endorsed by stakeholders in December was approved by a 61% vote. The D.C. OPC had proposed the issue charge in response to transmission owners' decision to file a new Tariff Attachment M-4 for the planning of critical infrastructure protection (CIP-014) mitigation projects (CMPs). (See "Critical Infrastructure Mitigation," *PJM PC/TEAC Briefs: Dec. 12, 2019*.)

The original issue charge said it would consider whether "procedures that provide stakeholder oversight of CMPs and CIP-014 facilities are appropriate."

Exelon's revision eliminates the term "stakeholder oversight," saying instead that it will "evaluate whether procedures are appropriate for stakeholder review of measures to avoid a transmission facility from becoming a future CIP-014 facility and of the process that would handle mitigation of future CIP-014 facilities."

Exelon's change also included a paragraph noting FERC's approval in March of the TOs' *Attachment M-4* filing. (See *PJM Remains Neutral in CIP-014 Debate*.)

Exelon brought the changes of the issue charge to the April PC meeting and agreed to delay a vote until the May meeting so discussion could be conducted with stakeholders. "We made an effort to make it clear that we'll be focused on the avoidance of future assets," Exelon's Robert Taylor said.

Greg Poulos, CAPS | © *RTO Insider*

Erik Heinle of the D.C. OPC presented an *alternative* to the redline version of the issue charge that included developing nondisclosure agreements regarding assets under CIP-014. His proposal was rejected, with 61% voting against it.

Heinle said stakeholders agree on wanting to address critical infrastructure avoidance. He said the biggest issue is determining the appropriate levels of confidentiality for projects.

"We should work on getting the policy right with mitigation, with avoidance, with confidentiality and send it to FERC and say, 'This is the best policy that we've drawn up to address these facilities,'" Heinle said.

Poulos said the Critical Infrastructure Stakeholder Oversight group is very close to finishing its work. But he said the Exelon changes removed the consumer interest from the Tariff in regards to CMPs. Poulos said the changes proposed by Exelon are not typically done in an issue charge, and he indicated that he may bring the issue up directly to the MRC.

Taylor said Exelon incorporated stakeholders' feedback in its revisions. "I think it's fairly inappropriate to come out of the gate saying that if we don't get our way out of the Planning Committee vote, we're going to take it straight to the MRC," Taylor said. "We've really tried to bend over backwards to take into account the concerns that have been raised."

PJM News

Emily Smithman of the New Jersey Board of Public Utilities said the BPU supported the original issue charge and disagreed with Exelon's changes. Smithman said the BPU views the changes as increasing noncompetitive transmission investment in PJM.

Taylor said Exelon doesn't see the mitigation of critical infrastructure as a competitive process, saying FERC has ruled that competition is not suitable for the assets.

"I don't think anybody has envisioned or proposed that there would be a competitive window for these projects," Taylor said.

PMU Placement First Read

PJM is considering using a "quick fix" Tariff revision to address the RTO's plans to expand the use of synchrophasors and formalize their placements into the RTEP.

Shaun Murphy of PJM reviewed the *problem statement*, *issue charge* and *proposed solution* during a first read to require synchrophasors — also known as phasor measurement units (PMUs) — in all new substations and major construction projects to monitor bus voltage and line flows. The committee will be asked to approve the issue charge and endorse the proposed manual language at the June PC meeting under the quick-fix process detailed in section 8.6.1 of Manual 34.

In the PJM *presentation*, Murphy said additional language is being proposed for section 1.4.1.3 of *Manual 14B* that would include a PMU Placement Strategy (PPS) to identify the synchrophasor device coverage needed to support the RTO's real-time synchrophasor applications. The PPS would include placement targets and required operational dates to guide installation plans and make mandatory a program that is currently voluntary.

Erik Heinle, D.C. OPC | © *RTO Insider*

Murphy said instituting the PPS would close the gap between research and real-time control room use, and improve data reliability and oscillation detection.

PJM completed a PMU data exchange with the Tennessee Valley Authority in February and expects to exchange data with Southern Co. and SPP later this year. The exchanges are intended to support reliability coordinator situational awareness and the Department of Energy's oscillation detection pilot, an effort prompted by the Jan. 11, 2019, *oscillation event*. (See *Oscillation Event Points to Need for Better Diagnostics*.)

Murphy said the communication equipment needed at each substation costs as much as $120,000, and each substation would have two or three PMUs that cost about $10,000 each. As many as 889 projects could be created over a 12-year span if a voltage threshold of 115 kV for each unit is accepted, according to data presented by PJM.

Calpine's David "Scarp" Scarpignato asked if the Tariff revisions would change the requirements for new generation having to install PMUs and if there would be any change for existing generators.

Murphy said PJM did not expect any changes for existing generators, but he said there could be an impact for generators on future generation projects depending on the manual language adopted.

Scarp requested that the impact on future generation projects be included in PJM's next presentation.

Dave Mabry of the PJM Industrial Customer Coalition questioned the RTO about the cost of the initiative. According to numbers provided in the presentation, Mabry said, the cost could be as much as $135 million.

"I think my clients aren't really sold that this technology is a need-to-have," Mabry said. "We're seeing it more as a nice-to-have and perhaps still not ready for prime time."

Load Forecast Update

Andrew Gledhill of PJM provided an *update* on estimated COVID-19 pandemic impacts on PJM loads.

Gledhill said the high-level findings of the pandemic's estimated impact on load has shown weekday peaks coming in 10% less than normal, or about 9,000 MW. Gledhill said the weekday peak impacts have ranged from 6.5 to 15.2%, with the largest estimated impacts happening on May 4 and 5 at 15% and 15.2%, respectively.

Energy has tended to be less affected by the pandemic, Gledhill said, with the average reduction since March 24 coming in around 7.9%. He said the hourly load shapes have been flatter than what is typically seen in the spring, and weekends seem to have been less impacted.

Gledhill said PJM has updated the RTO forecast using economic assumptions from April in place of the September 2019 forecast. He said planners intend to use the April economics for the parameters for the 2021/22 delivery year in the second Incremental Auction scheduled for July.

Whether there will be additional forecast updates has to do with the timing of the eventual 2022/23 and 2023/24 Base Residual Auctions, Gledhill said, as forecasters are still waiting for guidance on when the BRAs will run.

"This is an event that we've never seen," Gledhill said. "So, getting as much information as possible is key to understanding how it's affecting load and how it might affect load in the next several months or year."

Transmission Expansion Advisory Committee

Beaver Valley Reinstatement Cuts $93M in Tx Spending

The reinstatement of the Beaver Valley nuclear plant will eliminate $93 million in planned transmission upgrades, PJM told the Transmission Expansion Advisory Committee.

FirstEnergy Solutions (FES) had filed a deactivation notice for the two-unit, 1,872-MW nuclear plant in Shippingport, Pa., in March 2018, targeting a 2021 retirement. But Energy Harbor, the new name for FES after emerging from Chapter 11 bankruptcy in February, told PJM in March it would keep Beaver Valley in operation, citing Pennsylvania's plan to join the Regional Greenhouse Gas Initiative. (See *Beaver Valley Nuclear Plant to Say Open*.)

PJM initially identified $414 million in needed transmission upgrades after FirstEnergy announced the retirements of the Davis-Besse, Perry and Beaver Valley nuclear plants and six coal plants in 2018. The RTO reduced the projects to about $216 million after Davis-Besse, Perry and three coal units were reinstated last July.

With the reinstatement of Beaver Valley in March, the price tag has been cut to $123

PJM News

million, PJM's Phil Yum *said*.

He said eight baseline projects totaling $94 million are either already built or too far along in construction to cancel. Three other baseline projects totaling $8 million are still required for identified violations from the remaining deactivations, Yum said.

PJM's re-evaluation also identified a needed $21.4 million upgrade to the 138-kV Smithton-Shepler Hill Junction line (B3214), Yum said.

All pending baseline projects are currently on hold, Yum said, and a final decision on canceling the projects will occur after the completion of required RTEP analysis and interconnection service agreements (ISAs) for affected generation queue projects.

The Beaver Valley reinstatement was included in the 2025 RTEP model build, Yum said.

Beaver Valley Nuclear Power Plant

TO Supplemental Projects

TOs presented more than $300 million in supplemental project solutions to the TEAC.

American Electric Power

AEP will *spend* $120 million to reconductor or rebuild 18 miles of 138-kV lines and install a 138-kV +/-75-MVAR Statcom system for dynamic voltage support as part of a project in response to a customer request for new service west of Cameron, W.Va. The forecasted peak demand is 30 MW initially, with long-term prospects of 90 MW (AEP-2018-OH032). The $120 million project will address strains on the local 138-kV system.

Commonwealth Edison

Commonwealth Edison will *spend* $65 million to rebuild the 345-kV Itasca bus as an indoor GIS double ring bus expandable to breaker-and-a-half connecting four lines and two transformers (ComEd-2020-002).

ComEd also plans to spend $55 million to rebuild the 345-kV Elmhurst bus as an indoor GIS double ring bus expandable to breaker-and-a-half connecting two lines and three transformers (ComEd-2020-003).

Both projects are needed to replace straight bus designs that do not meet current standards.

Dominion Energy

Dominion Energy Virginia will *interconnect* a new substation by cutting and extending Line 2137 (Poland-Shellhorn) about a half mile to the proposed Aviator Substation with a four-breaker ring arrangement to create an Aviator-Poland line and an Aviator-Shellhorn line at a cost of $22 million. The new Aviator substation is needed to accommodate a new data center campus in Loudoun County, Va., with a total load in excess of 100 MW (DOM-2020-0003).

It also will spend $40 million to construct a 230-kV underground line from the Tysons Substation to a new Springhill Substation to replace the portion of existing overhead Line 2010. It will install a 230-kV, 50-100-MVAR variable shunt reactor at Tysons. The project, which will span about three-quarters of a mile, was requested by a customer and Fairfax County to allow construction of a planned mixed-use development (DOM-2020-0010). ■

— Michael Yoder and Rich Heidorn Jr.

PJM News

PJM Operating Committee Briefs

Black Start Issue Charge Endorsed

The PJM Operating Committee on Thursday unanimously approved an initiative to consider rule changes for the substitution and termination of black start resources.

David Kimmel of PJM reviewed the *problem statement* and *issue charge*, focusing on four areas in the Tariff that the RTO identified as in need of updates: testing requirements for black start resources not compensated through Schedule 6A; black start unit substitution rules; black start termination rules; and the black start capital recovery factor. (See *PJM Eyeing New Black Start Changes*.)

In March, PJM suspended an initiative considering fuel security requirements for black start units, which faced opposition from state regulators and consumer advocates. (See *PJM Backs off Black Start Fuel Rule*.)

Stakeholders also unanimously approved an amendment to the *problem statement* and *issue charge* proposed by Independent Market Monitor Joe Bowring to add an update to rules governing oil-carrying costs and minimum tank suction levels (MTSL).

Bowring said the *MTSL* issue has been left unaddressed in the Tariff for several years, leaving no clear language as to how shared resources like fuel tanks should be treated. He said many black start units charge customers for 100% of the MTSL. That charge is overstated when the tanks were sized to meet the needs of the generating units that share the tank and that use significantly more oil than the black start requirements, he argues.

The Monitor recommends that only a proportionate share of the MTSL for oil tanks shared with other resources be allocated for black start units, Bowring said, as this would help ensure that only costs directly related to black start service are paid by customers. (See "Black Start Fuel Assurance," *PJM Operating Committee Briefs: May 1, 2018*.)

Becky Davis of PJM provided *education* on black start testing, termination rules, substitution and the capital recovery factor.

The work time on the black start issue is expected to take two to three months, and implementation of the changes needed to governing documents is estimated to take about six months following the potential Tariff changes.

COVID-19 Still Impacting Load

PJM's Stephanie Monzon reviewed the April *operating metrics*, pointing to an hourly average error in load forecasting of 2.61% and a peak error of 2.31%.

Monzon said PJM continues to see the effects of state stay-at-home orders resulting from the COVID-19 pandemic and the impacts of warmer weather on load forecasting. Monzon said forecasters have predominantly over-forecasted on most days but remain within the target error of +/-3%.

Gary Greiner, director of market policy for Public Service Enterprise Group, asked about April 13, when PJM's forecast fell short by more than 8%.

Monzon said there was an unexpected morning peak in the Mid-Atlantic region. As the control room operators were adjusting for the morning peak, Monzon said, the models were trying to adjust for a different expected peak.

Greiner said that when the operator adjusts the forecast, that adjustment becomes the reported forecast and can have a major impact on pricing.

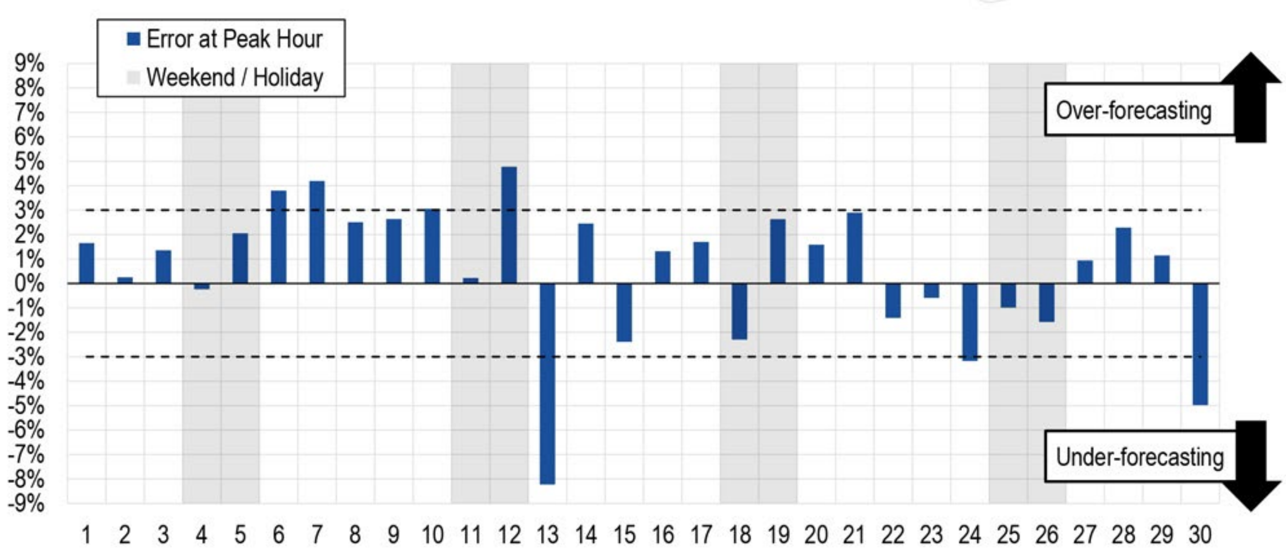
"It seems like I'm being nitpicky, but this is a huge driver of price, so it's an important error to minimize," Greiner said.

Monzon reported that the only spinning event for the month was also on April 13, lasting for eight minutes from 3:53 to 4:01 p.m. in the Mid-Atlantic Dominion sub-zone. Monzon said the event consisted of a Tier 1 estimate of 433 MW and a Tier 1 response of 207.2 MW.

She also said that overall, April was a quiet operational month, with five reserve sharing events with the Northeast Power Coordinating Council, 12 post-contingency local load relief warnings and eight high system voltages.

Two shortage cases were also approved, Monzon said, with both occurring on April 30 at 11:55 a.m. and 12:05 p.m. She said PJM was seeing generation that was expected to serve load start staggering online and had some generation trip off the system. ■

— Michael Yoder



Daily peak forecast error (April) | *PJM*

PJM MIC Briefs

5-Minute Dispatch Debate Continues

The Market Implementation Committee will be asked next month to choose between a PJM proposal and one from the Independent Market Monitor to resolve pricing and dispatch misalignment issues in the RTO's fast-start pricing plan.

PJM and the Monitor had been working on a joint proposal in response to FERC's January ruling holding the RTO's fast-start pricing compliance filing in abeyance until July 31 pending resolution of the *five-minute dispatch and pricing* procedures. But the two sides told the MIC in April they were unable to agree on implementation timing and now are backing separate plans. (See *PJM, IMM at Odds on 5-Minute Dispatch, Pricing Rules*.)

At the MIC meeting Wednesday, PJM's Tim Horger *outlined* the RTO's plan, which calls for three "work streams": short-term market changes to address pricing alignment; LMP verification "enhancements and clarifications"; intermediate operational changes to implement more "regimented" real-time security-constrained economic dispatch (RT SCED) case approvals; and long-term operational changes to investigate changing SCED timing and consider previous dispatch instructions.

Vijay Shah of PJM provided a *first read* of the RTO's proposed *Operating Agreement and manual changes*.

PJM's proposed short-term fixes align the locational price calculator (LPC) to use the reference RT SCED case for the same target time. LPC would calculate prices for the interval from 11:55 a.m. to 12 p.m. using the RT SCED solution for a 12 p.m. target time.

"PJM is committed to both the short-term changes and the intermediate changes," Horger said. "We will be moving forward with these."

Rebecca Carroll provided a *timeline* for the PJM intermediate solution that calls for conducting operator training and making software changes to limit automatic execution of RT SCED cases to once for every five minutes. Additional cases may be manually executed and approved as needed by dispatchers under what PJM calls this "intermediate" change.

Carroll said PJM already switched from a three-minute interval to four minutes for operators in February, moving closer to the desired five-minute dispatch interval. Carroll said no adverse impacts to pricing were discovered with the time change, but she said closing the gap gives less flexibility for operators to make changes in real time and urged being "cautious" before taking the next step.

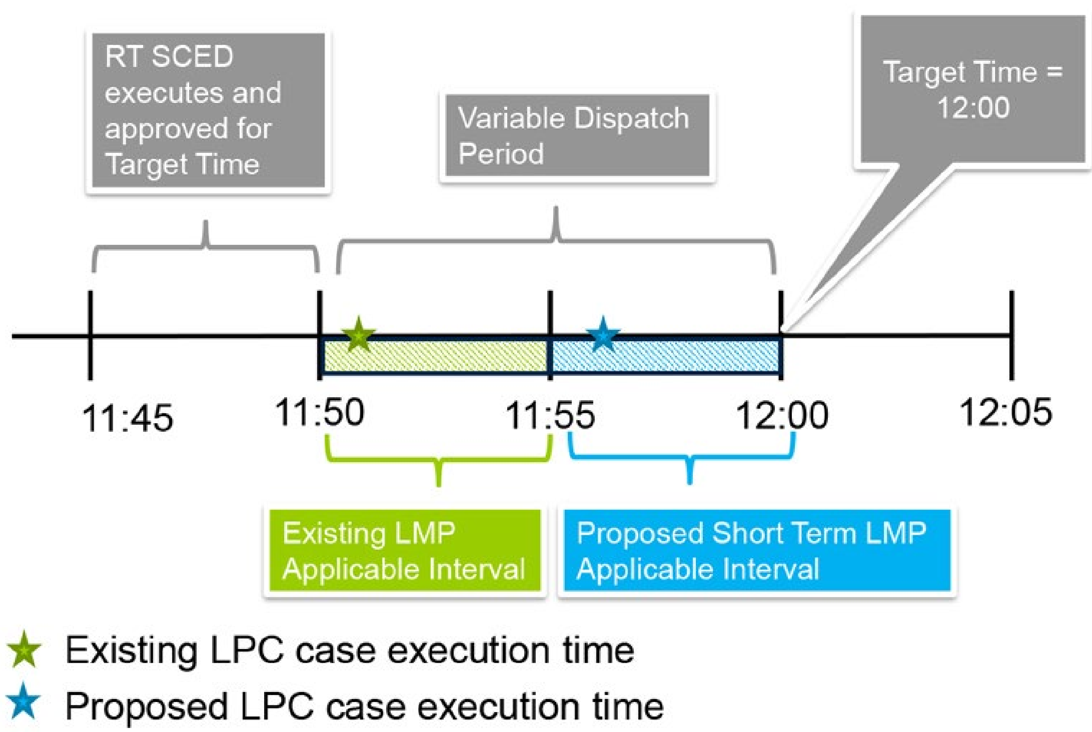
The "more regimented five-minute case approval [is] very different from what PJM's operators see today and have done [as long as] they've worked for PJM," Carroll said. "It's definitely going to be a philosophy shift in the control room."

Catherine Tyler of Monitoring Analytics presented the Monitor's *proposal*, which was originally the joint package between it and PJM. The RTO withdrew from the proposal at the April 15 MIC meeting.

Tyler said the proposal includes changes to dispatch SCED calculations and settlements, while the PJM proposal only includes making the settlement changes.

"The difference is not in the timing of implementation so much as commitment to making all of the changes that need to be made," Tyler said.

Carroll and Adam Keech, vice president of market services, insisted the RTO is committed to making the changes, although it can't say when. "PJM is planning to move forward to a five-minute periodic dispatch," Keech said. "We need to take operational precautions ... we need to learn along the way."



Proposed short-term implementation | *PJM*

Stability Limits in Markets and Operations

PJM's Joe Ciabattoni *told* the MIC that the RTO could support the Monitor's proposal to use capacity constraints to curtail generating output when needed to maintain stability during maintenance outages or continue using thermal surrogates.

Generating units must sometimes be reduced below their normal economic max limit if a planned or unplanned trans-

PJM News

mission outage presents stability problems that could result in damage to the units.

After stakeholder discussion and feedback at April's MIC meeting, "PJM can still jointly sponsor the existing package with the IMM but can also support the status quo," Ciabattoni said. (See "Work Continues on Stability-limited Generators," *PJM MIC Briefs: April 15, 2020*.)

Ciabattoni said some of the feedback received from stakeholders was that the stability constraint or generator output constraint doesn't fully resolve the issue that the LMP would not be aligned with the dispatch signal. Current rules require the RTO to implement a thermal surrogate to reflect the stability constraint in the day-ahead and real-time markets and to bind the constraint, affecting the unit's dispatch.

Tyler reviewed the Monitor's *proposal*. It says surrogate constraints are not modeled consistently in the day-ahead and real-time markets, resulting in differences that traders can take advantage of.

XO Energy FTR Forfeiture Rule Complaint

PJM's Thomas DeVita provided an *update* on the RTO's response to a complaint filed with FERC last month over its forfeiture rules for financial transmission rights.

XO Energy asked FERC to order PJM to change its FTR forfeiture rule or abandon it and adopt "a structured market monitoring approach" like the one used by MISO (*EL20-41*). The company said it exited PJM's virtual market in December after getting hit with $4.3 million in forfeitures. (See *Trader Challenges PJM FTR Forfeiture Rules*.)

Gary Greiner, PSEG | © *RTO Insider*

Thomas DeVita, PJM | © *RTO Insider*

DeVita said he couldn't give specifics as to how PJM is going to respond to the complaint, but he said the RTO's answer will focus primarily on compliance with FERC's January 2017 order (*EL14-37*). In that order, FERC instructed PJM to change how it implements the forfeiture rule, saying the RTO's focus on individual transactions failed to capture the impact of a market participant's overall portfolio of virtual transactions on a constraint. (See *FERC Orders Portfolio Approach for PJM FTR Forfeiture Rule*.)

PJM filed Tariff revisions in April and June 2017 describing its new approach (*ER17-1433*). In September 2017, the RTO began billing forfeitures based on its new approach, XO said in its complaint, even though the commission has never acted on it.

"It's been pending at FERC for three years, which is a significant amount of time, even by FERC standards," DeVita said.

Comments on the XO complaint are due June 1.

PJM Seeking Consultant on ARR FTR Task Force

PJM is seeking a consultant to aid the ARR FTR Market Task Force in a review of the FTR and other markets.

PJM's Dave Anders *said* the consultant is being hired in response to a recommendation of the *Report of the Independent Consultants on the GreenHat Default*, which called for expert help "to conduct a general review of the FTR market and other PJM markets in order to evaluate risks and rewards of structural reforms."

After focusing primarily on the education portion of the key work activities, Anders said the task force has reached the point of needing to engage expert help in the review process.

The scope and timing of the review is currently being developed, Anders said, with PJM looking at the task force's remaining key work activities to determine what can be accomplished and what should be put on hiatus during the external consultant review. The scope and timing plan will be discussed at the next task force meeting on May 27, Anders said, which has been cut back to a half-day of discussion.

Gary Greiner, director of market policy for Public Service Enterprise Group, asked if PJM has a sense of what the external consultant's mission will be. He said it would be important to have an idea of the scope of the work ahead of time in order to pick the right consultant.

Anders said PJM is currently working on the scope and welcomed ideas from stakeholders on what they would like to see included in the work.

"We want to share the scope with stakeholders, but we're not really ready yet because it's still in development," Anders said. "The selection is going to be interesting because there certainly are a number of experts out there that have deep knowledge of the products and the market."

'Quick Fix' for NITS Rule

The MIC approved an *issue charge* and a "quick fix" Tariff revision to address a regulatory change in Ohio concerning the billing of network integration transmission service (NITS). PJM requires load-serving entities to sign NITS agreements and post collateral based on their peak market activity. The expected duration for Tariff revisions is two to three months. (See "'Quick Fix' on PMA Credit Requirements," *PJM MIC Briefs: April 15, 2020*.) ■

— Michael Yoder

Dave Anders, PJM | © *RTO Insider*

Moving Ahead on MOPR

Webinars @ RTO Insider

RTO Insider Editor Rich Heidorn Jr. moderated a webinar on PJM's expanded minimum offer price rule last week with (clockwise from top) Rob Gramlich, representing the American Council on Renewable Energy; Jim G. Davis, Dominion Energy; Kathleen Barrón, Exelon; Todd Snitchler, Electric Power Supply Association (EPSA); and Independent Market Monitor Joe Bowring (not pictured).| © *RTO Insider*

RTO Insider Editor Rich Heidorn Jr. moderated a webinar on PJM's expanded minimum offer price rule (MOPR) last week with Rob Gramlich, president of Grid Strategies, representing the American Council on Renewable Energy; Jim G. Davis, electric market policy consultant for Dominion Energy; Kathleen Barrón, senior vice president of federal regulatory affairs and wholesale market policy for Exelon; Todd Snitchler, CEO of the Electric Power Supply Association (EPSA) and Independent Market Monitor Joe Bowring.

Below is a transcript of the session, which has been lightly edited for clarity.

RTO Insider:

Good afternoon, everybody. We're thrilled you've all joined us for what we hope will be a lively and enlightening discussion on the future of the PJM capacity market under FERC's expanded minimum offer pricing rule — MOPR to its friends. I've been involved with PJM on and off since the late 1990s, covering it closely since 2013 when we launched *RTO Insider*. In the last seven years, we've seen continued tinkering with PJM's capacity market and increasing dissatisfaction with it. Now this is not all PJM's fault — the failure of the federal government to deal with carbon emissions has left the states on their own.

But the reality is, there are now two bills before the Illinois legislature to pull the ComEd zone out of the market for a fixed resource requirement [FRR]. Regulators in New Jersey and Maryland are also looking at exiting the market. So that sets the stage for today's discussion on moving forward with MOPR. We scheduled this webinar for today because Friday is the deadline for comments on PJM's first compliance filing in response to FERC's December order. If you recall that order extended the MOPR to new and existing state subsidized resources, with some exceptions mainly existing DR, energy efficiency, self-supply and renewables in RPS programs. Since we scheduled the webinar, we've had the commission reject the hearing requests, which opened the door to appeals to the federal courts. We'll be touching on all of these issues today. Let me say at the onset that we invited PJM to join us in this conversation, but the RTO chose not to send a representative. No matter, we've got a terrific lineup of speakers. And let me introduce them one at a time here.

First, we have Jim Davis, who is the electric policy consultant for Dominion Energy. Welcome, Jim.

Jim G. Davis, Dominion:

Thank you, Rich.

RTO Insider:

And Todd Snitchler, CEO of the Electric Power Supply Association.

Todd Snitchler, EPSA:

Good afternoon, Rich.

RTO Insider:

And Rob Gramlich, who is president of Grid Strategies, who is representing the American Council on Renewable Energy. Next, we have Kathleen Barrón, senior vice president of federal regulatory affairs and wholesale market policy for Exelon. Did I get the accent better that time, Kathleen?

Kathleen Barrón, Exelon:

Well done, Rich.

RTO Insider:

Thank you, thank you. And last but not least, from apparently a bunker at an undisclosed location is Independent Market Monitor Joe Bowring, who has security restrictions that block him from using video. Hey Joe, can you hear us?

IMM Joe Bowring:

I can, can you hear me?

RTO Insider:

We can hear you, excellent. Well what we're going to do is, I've got some questions for each of you and for the group as a whole. We'll also, as Merry mentioned, do several polling questions. We'll start off with some opening comments from each of you on how you're coping with the pandemic and your top-of-mind comments on where we are in the ongoing [MOPR] saga. We ask you to limit your comments to two to three minutes. Merry will

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be timing and we'll send you an electric shock if you go over.

So, let's start with you, Jim. Tell us where you're at.

Jim G. Davis, Dominion:

OK, thank you. Appreciate being here today. I know this is an unusual time for us all but we at Dominion, we believe that the capacity market should accommodate state initiatives, their clean energy policies and the planning of clean, renewable energy. Driven by our commitment to achieve net zero emissions by 2050 and recent legislation in our state, we submitted our 2020 IRP [integrated resource plan] to our respective state commissions. It provides a forecast of the variety of options that we may pursue, with a total of 23,700 MW of clean, renewable generation over the next 15 years, including over 5 GW of offshore wind.

As Rich mentioned, in a few days we'll be filing our comments with the commission in response to PJM's March compliance filing. The FERC's recent orders defined state subsidies and provided guidance for PJM to implement the expanded MOPR. Unfortunately, the overly broad definition creates a significant amount of ambiguity that has heightened concerns amongst PJM stakeholders over the development of new, clean, renewable resources. Some of these concerns are warranted because the FERC's orders virtually require all new resources to offer at higher replacement rate, which puts them at risk of not clearing the capacity auction, leaving states and self-supply entities contemplating other options.

Although the recent FERC orders on rehearing attempted to clarify the December 2019 order, they may have compounded the confusion over the broad definition of state subsidy. It is for this reason that we advocated, as a company, for a simpler definition of a state subsidy.

In terms of timing, we believe the auction timeline that PJM proposed, which hinges upon the final FERC order [on compliance], will create greater certainty for market participants. The auction timeline will allow states to enact new laws, market sellers to make the appropriate investment decisions and afford PJM the time to perform any pre-auction activities under the new capacity market construct. The impact on the new capacity auction remains to be seen. There's uncertainly how the interplay between FRR elections, resource retirements and exemptions will [affect] the capacity clearing price.

What is certain, in these extraordinary times, is that all of us, the states, market sellers and utilities, need clearly defined rules to help us make well informed decisions regarding laws, generation retirements and new project investments while maintaining reliability in the grid. Look forward to [the] discussion, thank you.

RTO Insider:

Thank you, Jim. Let's turn to Todd, who I think has a somewhat different perspective on the MOPR ruling.

Todd Snitchler, EPSA:

Thanks Rich, appreciate it and appreciate the opportunity to participate today. I think most people on this call know, EPSA represents the competitive power generators and our members own and operate north of 150,000 MW in all markets across the country. But of course, the attention today is on PJM and the effect of the MOPR order. I think it's important, as we start out, to talk about the impacts of COVID-19 and what it has meant to the states that are impacted and the country as a whole, with more than 20 million Americans who have lost their jobs since April. Approaching 20% unemployment, state and federal budgets are at a breaking point. And I think it's important to reiterate that now more than ever, we need to make sure that we have reliable and affordable electricity. And so I think we try to balance that with the impact on climate, which certainly our members — if anyone's been reading the news over the last couple of months — have made a point to try to make our position clear: that market-based outcomes or market-based mechanisms to drive environmental outcomes are things we're supportive of, including a price on carbon, if that's the preferred vehicle.

But it's important for us to look at how we get there from here. So, one of the things that we wanted to talk about today, what is the right market design and how can competitive power suppliers rely on the market to generate their revenues. Because unlike regulated utilities or vertically integrated utilities, there's no

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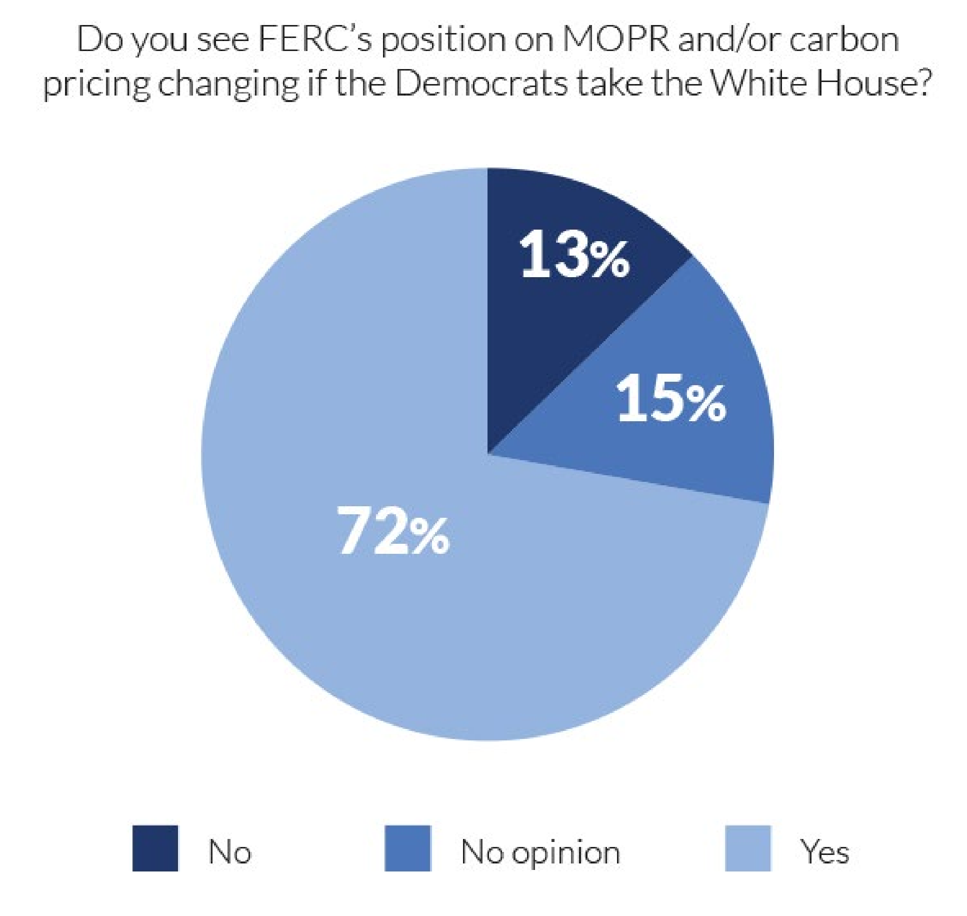

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Moving Ahead on MOPR

guarantee that our members can make money, based on their operations. They have to be efficient; they have to operate in a way that allows them to dispatch and to be competitive. And having a defined set of rules — I think Jim and I would agree on that — is the way that allows all market participants to have the opportunity to compete. And that's really what we're trying to achieve, is a level playing field for all market participants to have an opportunity to compete in a way that allows us to achieve objectives that are important.

I think it's also important to note that competition shields consumers from risk and the competitive power suppliers have shifted the risk back to their investments, to their investors and shareholders, as opposed to putting it on the backs of utility consumers. And we think that model has worked and has resulted in efficiencies and cost savings.

So to get more to the point of the MOPR, I think we've spent a lot of time over the last several months batting around what's good, what's bad, what some entities like, what some entities don't like, and what are the merits or demerits of the order. But I think what really the success of the MOPR has been to elevate our discussion around what does market design need to look like. Because the market is evolving and resources are changing and so we need to look at what the market is actually being asked to achieve. Because that would define how the market should function. But in the end, it's important that … there remains competition among power generators. When you return to a noncompetitive model, consumers lose. And that's not a particularly good outcome from our perspective.

So, the ins and the outs of the order, I'm sure we'll talk a little bit about as we go forward. But at the end of the day, when companies compete, customers win. [As] a result of competition we've seen cleaner resources being added to the queue, you've seen higher emitting resources that are uneconomic retire and move off the grid. We've seen deployment of innovation, including our members that have invested in storage and renewables projects in PJM as well as in other parts of the country. And we think that speaks well of how a properly constructed model could work. From our perspective, the ability to create a durable, regulatory framework for sustainable environmental progress is what a lot of the states seem to be suggesting they want to do. And we think that a more centralized approach — and not a patchwork of states — is the most efficient way for us to achieve those objectives. And it really is going to be incumbent upon market participants to find the right market design to try to achieve those objectives.

So, with that, I'll turn it back to you, Rich.

RTO Insider:

Thank you, Todd. Let's turn to Rob.

Rob Gramlich, ACORE:

Thank you, Rich, thanks everybody. Great to be here, as Rich mentioned, I'm representing ACORE today: American Council on Renewable Energy, which is a national organization focused on renewable energy. It occasionally gets involved in the regions and has popped up at stages of the MOPR debate, which is not just a PJM issue, it's a New York and New England issue, potentially others. And it's not even necessarily a capacity market issue. So, there's a concern about FERC and RTOs interfering with state policy. This is against the backdrop of I think a pretty broad consensus in the renewable industries that markets are absolutely critical for renewable energy development, especially large regional RTO operated markets. And so, there's not at all an attempt to retreat from that. In fact, we're trying to promote those things in the Southeast and the West. And this MOPR has done more damage than anything since the California flawed initial market design [to] that agenda. Just talk to people in those regions about why they fear moving things into FERC jurisdiction.

So, it's an unfortunate, unforced error. Hopefully, the courts will fix it. But here we are, we don't know what the courts will do, we don't know what a future FERC will do. We've got MOPR, in fact, we've got a new form of MOPR. I did an estimate of a previous version of MOPR last August and came out with an estimate of up to $5.7 billion cost of MOPR. That was again, one version. What FERC approved is now a totally new version, so the numbers are changing. This thing is a moving target. It's hard to pin down. PJM filed — generally I think — helpful compliance provisions. So, I think we'll see generally favorable compliance comments come in from renewable industries this week. But I think everybody in the renewable industries will also be clear that the fundamental premise of MOPR or at least a broad MOPR that interferes with state clean energy policy is not FERC's role or the RTOs' role. And so there will be petitions to the court, just on the fundamental premise of the whole thing.

This latest version, we're still looking at it, what FERC approved with new provisions like the utility self-supply and how it treats the demand response and energy efficiency. So, there are a lot of new aspects to it, in some ways it raises more questions than answers. It's also kind of FERC's baby now. This is not, I think, what PJM is recommending or very much close to it at this point. So, it's really what a couple commissioners at FERC want and it's kind of out of control of the PJM process, which is another reason I think states and stakeholders should be troubled by it.

> **"This MOPR has done more damage than anything since the California flawed initial market design [to] that [pro-competition] agenda."**
>
> —Rob Gramlich, ACORE

So, we'll talk, I assume in a minute about what potential state reactions are. And I think that is an important discussion because states have … to consider their options at this point. And let me close by agreeing with my friend, Todd, that a very fruitful discussion would be to think about the longer-term market design. What is really needed, let's consider a couple resource portfolio options and how do you appropriately compensate both the carbon-free resources and then whatever all their firming resources are, whatever reliability services are needed to make sure the system is balanced all year round. So, and I've heard similar comments from [PJM CEO] Manu Asthana, so I'm encouraged that there may be some forums for that type of longer-term discussion. I'll turn it back to you, Rich.

RTO Insider:

Thank you, Rob. Kathleen, why don't you weigh in here?

Kathleen Barrón, Exelon:

Sure, and good afternoon, everyone. I hope everyone is staying safe and healthy. You asked us to comment on how each of us is handling the pandemic. Here at Exelon, we have about 34,000 employees, about half of them are in the workforce, keeping the lights on. We've done refueling outages this spring and I'm happy to say, despite having — as is necessary in events like that — large numbers of workers doing important essential work [we've had] no or very low cases at each of those outages. And

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our field workers throughout the six utilities in our family are safe and doing what they're doing so that all of us can enjoy the technology in the safety of our homes as we do things like this. So, thanks to *RTO Insider* for inviting me, I think I'll dovetail somewhat with what Rob was just saying, in terms of where we sit right now.

We have a FERC that's announced MOPR as its standard solution now in three RTOs and denied rehearing on the most expansive version of it in PJM. So, the question really is: Where do we go from here? And I think the answer to that depends on what your goal is. We tend to line up with customers and our states who continue to want clean energy at an affordable price. Particularly now when the world is facing a respiratory illness that's exacerbated by air pollution. It is leading many of them to explore the FRR sort of escape hatch, because that will allow them to chart their own clean energy path, design their procurements so that they can get the clean energy future that they want while staying within the broad PJM framework for things like moment-to-moment dispatch transmission reliability planning and the like. And to the core point of what Todd said, the value of competition to our customers is clearly undisputed. What we're really talking about here is giving the states the authority to have like products compete against like products.

So have clean compete against clean and have emitting compete against emitting, as opposed to having a product that is without air pollution compete against a product that has air pollution but doesn't pay for it. So that's sort of the core issue here: Are states going to be allowed to design their own procurements and FRR as a way for them to continue to do that while staying within the broader PJM family? I do think it's again without dispute that the states really have led the way on clean energy policy. There's 47% of Americans who live in a state with either 100% RPS [renewable portfolio standard], 100% clean energy standard [CES] or a high emissions-reduction target. And there's 10 states that have carbon trading along with a credit program. Either an RPS or a CES. So, it's just not reasonable in our view to think the states are going to say, 'Oh never mind,' to a policy that has the express purpose of making their credit programs more expensive to implement. I do think there will continue to be entities that fight the states in going down that path, just as vigorously as they fought for MOPR in the first place.

As you have heard this afternoon, we should all work together on a new policy, some sort of policy that uses a tax or carbon trading as a way to internalize the cost of emissions. And as a company that's been advocating for that for over 20 years, we certainly welcome those discussions. And I hope I'm wrong about this, but I think what you will see is it's not going to change that much in terms of the ongoing debates. You'll still see entities lining up, pretty much, the way they have lined up on the debates going back 10 years. And last week was a perfect example of that. There was a vote in Pennsylvania on the issue of how Pennsylvania should move forward and should it join RGGI [the Regional Greenhouse Gas Initiative], the regional carbon trading program. The clean energy community all voted yes in that stakeholder vote and one of Todd's members, NRG, voted no. So, it's just not that surprising that entities are lining up in different places on these policies.

Given that we have an oversupply of capacity at PJM, prices are extremely low, even before COVID. There's a lot of high-emissions fossil capacity out there, sort of hoping that MOPR will keep them online and push new, clean energy out of the market. To give you an example, our company makes about the same amount of energy as three of Todd's largest members, NRG, Vistra and LS Power. We make just under 200 TWh of electricity a year and together, those three companies make a little bit more than that. But they emitted 158 million tons of carbon in 2017 while we emitted 10. So, we just have dramatically different emissions profiles and that's driving the debates over whether we should have had a MOPR in the first place and where we should go next. We do have a lot to do, we have compliance filing comments to write, we have appeals to litigate, we may have a new commission, as Rob said, at some point, that will rethink all of this. But we've been in this MOPR battle for about 10 years and it really comes down to who controls the outcome for customers, whether it's the states or the federal market. I don't see the

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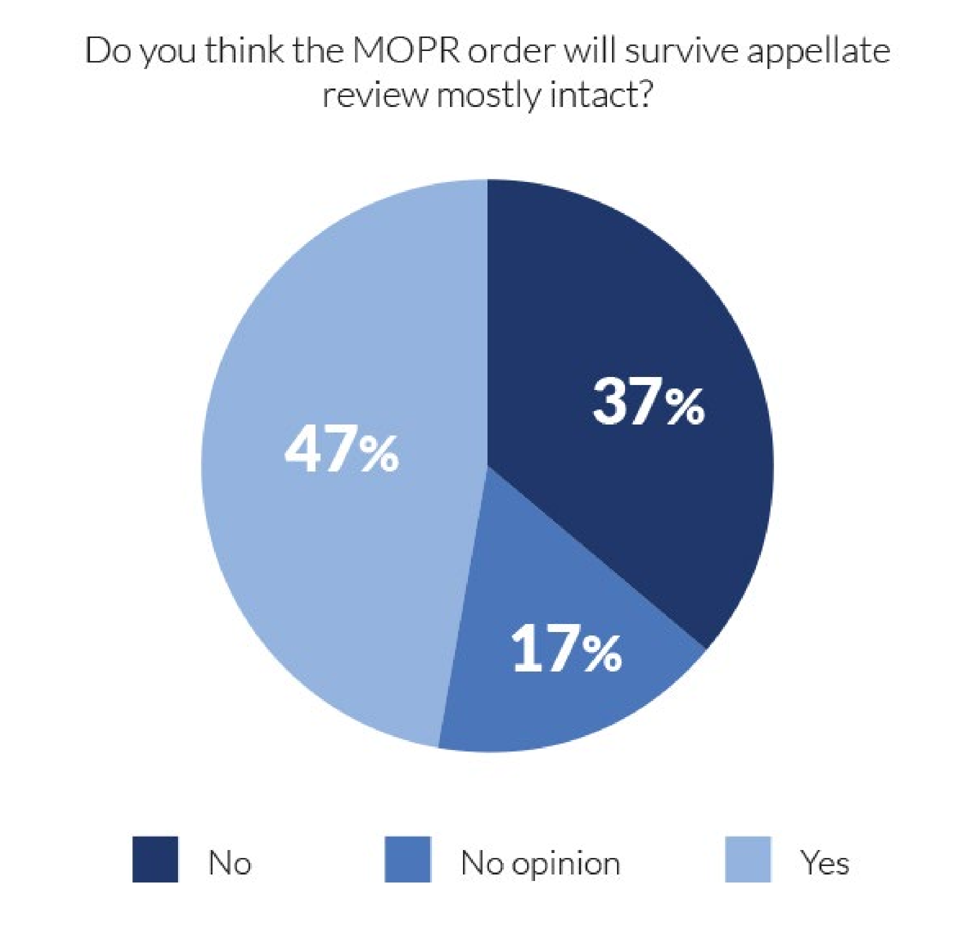

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states forgoing their right — and really what they see as their obligation — to continue to protect their customers by pushing clean energy policies. So, I'll stop there and I'll look forward to questions.

RTO Insider:

Thank you, Kathleen. I'm sure Todd will want an opportunity to respond to that one point in a moment, but first let's get Joe Bowring into the discussion. Joe, you have some breaking news today. You just released your third FRR analysis, this one for New Jersey. (See related story, *PJM Monitor Finds Capacity Exit Costly for NJ*.) Maybe you can kind of summarize your overall conclusions from these three analyses and then maybe touch on briefly, specifically what you found in New Jersey.

IMM Joe Bowring:

Sure. First of all, it's great to be here. Thank you, I hope everyone's doing well. Let me just start with an overview as the other folks did, and then go to those FRR reports for a moment. So, in this entire debate, it's essential to be analytical. I think there's been a lot of overreaction [to MOPR], multiple red herrings. I mean, FERC did what they're supposed to do. FERC drew a jurisdictional line, that's what they're supposed to do. They told the Illinois court when they decided not to take a position in the Illinois court in the case there, that they would draw that line and now they've done that. There are obviously competing areas of jurisdiction, there's state and federal. The state should not intrude on wholesale power markets and similarly, the federal government should not intrude on state decision-making authority.

I think that the FERC's line is logical, consistent and coherent. You may not like where it's drawn, but it is all those things. And despite all that, states have the authority over generation, ultimately. They can rely on cost of service, they can rely on FRR, they can rely on markets, they can do the MISO model, they can do the fully regulated model. They have total authority. And to date, in PJM the states have chosen markets and markets have proven to be an effective way of providing low cost energy to their customers.

There is no evidence that MOPR will raise prices, despite much of the talk. In fact, what we found is the FRR is likely to raise prices, although we're not predicting it will. Generator supporters of FRRs are not doing so because they expect their revenues to be reduced. Of course, they're doing it because they expect their revenues to be increased. One of the fundamental problems with the FRR model is it provides market power to small number of generators in each smaller FRR entity.

Fundamentally, FRR is a non-market approach. Under the FRR approach, state authorities and generators would set prices. There's an asserted benefit of stability over volatility; of course, regulated rates are always stable; markets are more volatile. That doesn't make non-markets better but it's a point that is made. And it's likely to support IRP over incentives. Planners will decide what the best technology is, rather than providing incentives to market to produce the lowest cost. New innovations that we have we need to start to think about. Our basic point is that markets with rules work. No one's advocating laissez faire but markets with rules work and have worked very successfully in PJM for 20 years. And in particular now, markets plus specific subsidized resources are likely to be the least-cost option for states that want to subsidize specific resources. There's no reason to reject markets, even if there are certain subsided resources that you want to support.

In fact, what we've seen is we don't believe that the subsidized resources will not clear; in fact, we think they will clear the market. And we think competitive markets are an entirely good venue for the continuation of both nuclear power plants as well as renewables.

So that was my opening, do you want me to talk for a minute about the FRR, as a segue to the next part of this? Our reports?

RTO Insider:

Yeah, briefly describe your findings.

IMM Joe Bowring:

Sure, so just very briefly, this is our third report. We've done one for ComEd, we've done one for Maryland, now we've just done one for *New Jersey today*, which we will submit to [the] New Jersey [Board of Public Utilities] and their process. Similar to the other ones, we did a high [price] case and a low [price] case. And in almost every case, it resulted in higher cost to customers in New Jersey. And we did a couple scenarios, we did all of New Jersey, we did PSEG separately and we did JCPL separately. And again, our basic overall point is that FRRs are not a panacea. FRR is a term that's really not very well defined and the exact rate making process will be the result of negotiation. It won't even be as good as former cost of service regulation. It'll be some less clearly defined way to define what customers actually pay and there are at the moment, no rules governing [it]. Every state will do it their own way. But there's simply no reason to believe that this non-market approach will be good for customers, will provide the least cost option for customers, it'll provide incentives for renewables or whatever form of energy you favor.

> **"There is no evidence that MOPR will raise prices, despite much of the talk ... Generator supporters of FRRs are not doing so because they expect their revenues to be reduced. Of course, they're doing it because they expect their revenues to be increased."**
>
> —IMM Joe Bowring

I mean, that's it, at a high level.

RTO Insider:

Great Joe, thank you very much. Let's go to our next polling question, which is as Rob alluded to, the possibility that the composition of FERC could change. So, if you can call that up, Merry, we want to ask [the audience]: Do you see FERC's position on MOPR and/or carbon pricing changing if the Democrats take the White House in November?

All right, well I think it's pretty clear, people do expect that to have an impact. We won't ask you what are the odds that that'll happen because a lot can happen between now and November. But thank you very much for participating.

Let me turn back to Jim. Jim, you alluded to the IRP that Dominion released on May 1. This would, as I understand it, quadruple the amount of solar and wind generation in your previous 15-year plan. Energy storage capacity projected to increase seven-fold, to 2,700 MW, which you say is the most ambitious target in the country. I can remember a few years back when the environmentalists were complaining that Dominion was dragging its feet on offshore wind. Now you're planning to build 2.6 GW yourself. The state has a target of 5.2 GW. Arguably, these policy shifts wouldn't have

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happened had it not been for the Democrats' takeover of the legislature and the governor's mansion. But what does it mean for the culture of Dominion to be moving so aggressively now into renewables and storage? You haven't been seen as being on the forefront of that up until recently.

Jim G. Davis, Dominion:

Sure, and appreciate the question. It is a very exciting time to be working with Dominion. We actually had our own goals to go net zero by 2050 so we're embracing change. We're seeing where the industry is going and that's kind of been a significant culture change with our organization. First, in terms of the IRP, it is a snapshot in time. It is filed every three years in Virginia, and North Carolina. We're forecasting and providing a variety of options that we may pursue, giving diverging scenarios. So, this one is a significant change. We do take into consideration the existing technology that we have and know of today, that exists today. As technology improves, the cost ... will ultimately reduce. But there's both qualitative and quantitative benefits to consider as well. So, for example, with our offshore wind projects, we see that being a way to also drive economic growth within our state. There's technology out there or that is coming down the pike that we don't even know exists yet. So, we're looking at things as that.

But in terms of the IRP, we're modeling what we know. And also, there's been essentially four models that have been presented to the state corporation commissions. So, there's different scenarios that we've evaluated.

RTO Insider:

And are all of them threatened by the MOPR? Or made more challenging, at least?

Jim G. Davis, Dominion:

I guess in terms of the cost, with these new resources being I guess MOPR'd — I don't know if that's a real term — it does run the risk of those resources not clearing the auction, and considering that our state has now mandated by law targets for our renewable portfolio standard, it definitely makes it challenging, so we are taking a look at the options, and one of those options is FRR. But at this point, we haven't made any decision because we haven't seen a final ruling.

RTO Insider:

Can you say whether the company is leaning one way or another? I know that the IRP specifically said that you are undecided.

Jim G. Davis, Dominion:

Not at this time.

RTO Insider:

OK, great. Well thanks very much. Todd, let me come back to you. You've talked about your view of what a durable, long-term solution would look like for PJMs capacity auction. What are the obstacles to achieving that vision and what would it entail?

Todd Snitchler, EPSA:

Thanks for that question, Rich. I want to come back and have a chance to respond to Kathleen's comment about emissions and the straw man that continues to be thrown up and beat around. I think it's important to note that NRG and Vistra, who she mentioned in her examples, have commitments to cut their emissions dramatically and thus far, NRG has reduced their CO_2 emissions by 40 million metric tons in the last 10 years. And Vistra has cut their CO_2 emissions by 31% since 2010, which is almost 170 million metric tons. So I think [to] say that these emitters are going to continue to just do what they do because they're not willing to make commitments to participate in what the grid may look like in the future, is a bit of a misstatement. I try not to speak for Exelon, so I'll appreciate the full story being shared when it comes to our members and what our members are doing.

But with regard to your question about the durable regulatory framework, I think there's a number of challenges. One, there's a lack of trust amongst the parties. You have states that need to be engaged and involved because they are the ones who have the authority to make those policy choices. And certainly, they have done so in many jurisdictions. And so, the states need to understand and feel comfortable that they're invited to the discussion at the table. You've got the transmission owners that also have an interest in how this would shake out. And I don't know that there's a lot

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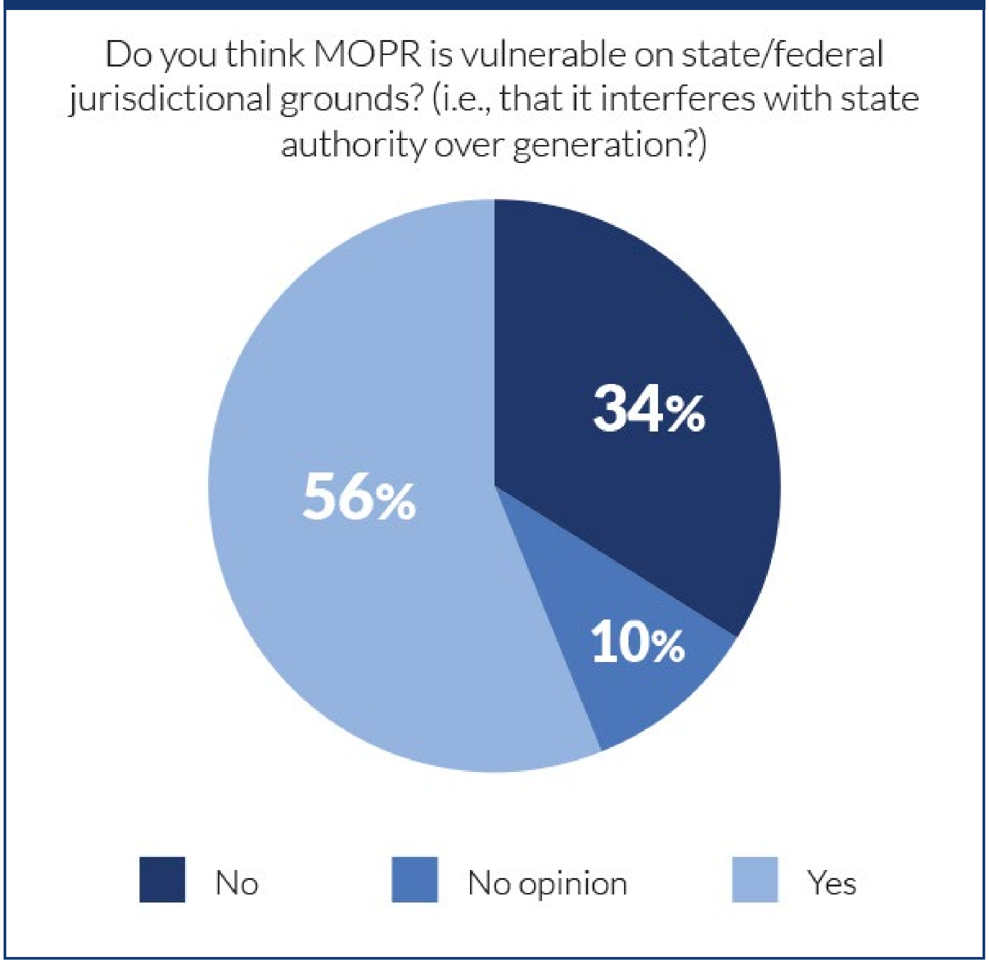

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Moving Ahead on MOPR

of trust between the transmission owners and the generators, because of course the generators are also the ones who have to be bound by whatever the new market construct would look like. Right now, the market isn't designed to achieve low emissions. It's been a side benefit of a lot of retirements of coal facilities and the addition of renewables and natural gas, but that's not what the market was designed to procure.

And so when we design a market that will look to actually do what states may want it to do, then you could get an outcome where you achieve the lowest cost by using it across the largest possible footprint instead of that state patchwork. And that's better for consumers. I can't guarantee that that's going to allow every state to achieve the exact specific goal they've set out in the timeline they would like. But if you're trying to balance a number of interests — which I think you have to do — you end up in a position where you can still advance the ball significantly, try to achieve many of those objectives and then look for ways around the edges that might help fill in some of the gaps that could exist.

But it's really getting people that want to have a meaningful dialogue around that issue— not protect the gains that they've already locked in for their organization to the determent of others — but have a real, meaningful conversation about how we could all work on this kind of a durable framework. Because frankly, at the end of the day, constant litigation and revisions are not helpful for creating market certainty, no matter what your model. And so, I think if we can get over some of the trust issues and the desire of some to put their interests ahead of others in a pronounced way, I think would help us really initiate a meaningful conversation.

RTO Insider:

Great, thank you, Todd. Let's take another poll question here. Here's another potential answer for this entire situation, which is: Do you think the MOPR order will survive appellate review mostly intact?

All right, well we seem to be settling in at about 46% yes, 37% no. That's very interesting, I would have thought it have been a little closer.

All right. Well let's turn to Rob. You mentioned that you had done your earlier computations on what you called MOPR 3.0 and they don't apply to MOPR 9.0, the version you said IMM used in its analysis. You've also said that you think the PJM compliance filing provided a better outlook for renewables than you initially feared after the December order. How confident are you in the ability of renewables to continue gaining market share under MOPR?

Rob Gramlich, ACORE:

Thanks' Rich. I think a lot of it depends on what FERC does and anybody who's tried to predict FERC decisions up til now I think has been disappointed. So, it's very hard to predict what they will do with the compliance filing. It doesn't take a lot of capacity excluded from the capacity market to have a pretty significant influence on price. A 3- to 6-GW swing in the capacity allowed to participate can swing prices $30 or $50/MW-day, or 25% or something like that. So that's what 3 to 6 GW does, and there's still about 14 GW under state RPS around the region that are subject to MOPR. That's on an unforced capacity basis.

So, there's three times more capacity subject to MOPR than the capacity needed to have a significant price swing. So there still can be a significant impact on price from MOPR even in this current construction. Again, it depends a lot on what FERC does with compliance filing, in particular as it pertains to renewables on the unit-specific [exemption] process It could come out a little better.

But I don't think anybody can conclude that MOPR has a low or minimal cost. Especially if you look after the first auction. Maybe the next upcoming auction will have limited impact because there won't be much offshore wind in that, for example. But pretty soon after that, there will be. So, I do expect there will be costs from MOPR and that states are, unsurprisingly, looking at their options as a result.

RTO Insider:

Kathleen, let me bring you into this discussion. If resources that are currently participating in state clean energy programs can't earn capacity revenues, how much of an impact do you see that having on the cost of existing clean energy programs?

Kathleen Barrón, Exelon:

Thanks for the question, Rich and I appreciate the way you put it there. Because we tend to have debate over what MOPR is going to cost customers and that's really a question of what impact MOPR will have on the capacity price. And there have been a bunch of estimates; Rob mentioned one that he did; Commissioner [Richard] Glick did another one. And those are difficult to do because they're a function both of the compliance filing process but also how folks bid and supply/demand fundamentals and a bunch of things; Joe Bowring can explain better than I can. But the question you're asking me is, to the extent renewables going forward cannot continue to participate in the capacity market — recognize that not all of them do today, because of things like Capacity Performance penalties and other things that sort of push them out. But to the extent that none of them are going to participate going forward because of the default MOPR values or because their own financing costs do not result in a unit-specific bid that would allow them to clear. What does that really mean for customers?

And so, we have done some analysis on what that means in Illinois, which in particular has a pretty aggressive emission reduction target and has some renewable goals. So if you look at the 2030 renewable goals and what they will cost to achieve if renewables are not allowed to participate and earn capacity revenues, at a pretty conservative assumption level, the cost between now, which is really 2022 when the next auction is applicable for and 2030. It's $1.5 billion that's lost revenues to renewables in the state of Illinois that would need to be made up for through an RPS budget and through rec credits. So that's what you could sort of conservatively look to as the cost of this policy, in Illinois, to customers and that's just one state, of course. If you look across all of PJM and you add up all of the renewable targets across the 13 states and the District of Columbia, you get a number that's probably 10 times that in terms of what customers need to spend in order to make up for lost capacity revenues that are, of course, going predominantly to fossil resources.

RTO Insider:

Thank you, Kathleen. Let me ask a follow up question. Last month, a broad coalition — those who support the RPS standards and generators who say state subsidies distort capacity markets — asked FERC for a technical conference on integrating carbon pricing into the wholesale markets. So, we had both Calpine, ACORE, [the American Wind Energy Association], groups that are on very different sides of the MOPR debate. But Exelon was not part of that group. Why was that? Were you not invited, or did you have policy differences with the way their letter was structured?

Kathleen Barrón, Exelon:

A couple of answers to that question. I mean the shortest one, we really tripped over a line in the petition that says that the folks filing it were not asking the commission to institute a rulemaking proceeding nor were they suggesting that FERC should direct implementation of a carbon pricing mechanism. So happy to show up, participate in any discussions over carbon pricing as we have for many, many years. But we sort of thought that line took a little bit of wind out of the sails because it's not asking for a carbon price to be implemented in the market. It's asking for FERC to have a conference, like what you're having here today, and talk about the issue. We've been talking about the issue for many, many years. In New England, we've been talking about it. In New York there's a robust plan to put a carbon price in the market in New York. We've been pushing PJM for years and years to talk about this and continue to get pushback at the state levels, even over looking into not just the carbon price but leakage mitigation, which is sort of a step below carbon pricing. So again, [we're] glad to have another conference to talk about carbon pricing. We will participate; we will file comments. But we want to see action; we don't really want to have another conference on this topic.

RTO Insider:

OK, great. Thanks. Joe, let me bring you back in here. You have said that people are hyperventilating over MOPR — my words not yours. But you have suggested that in your analysis that at least in the initial year, it will not increase costs. How can you be so confident and what are your predictions about the impact beyond years one and two? Do you think wind and solar resources really are competitive now and if so, why would states continue to spend money on renewable energy credits [RECs]?

IMM Joe Bowring:

So, the last question's a very good one, we'll get to that. There's no plausible path to short-term MOPR price increases no matter what all these estimates allegedly support. And the reason's very simple. The technologies which are asserted to be not clearing are either exempt from or extremely likely to clear in the market. So, the nuclear net MOPR floor is very low and the renewables are all exempt. So, for the first two years, it's really, I don't even think it's a question. I mean, it's quite clear there is no plausible way that the MOPR will increase prices. But it is a reasonable question to ask after that. So, the first auction will be 2022/23, the next one will be 2023/24 so when we're talking [about the] 2024/25 auction, that's a ways out. First of all, I believe that renewables are competitive right now, generally, and I believe and again from based on both what we know and what we hear from those who are in the business, even more competitive.

So, the question is, do the supporters of renewables really, truly believe that they're not competitive and can't compete in a market? I think the market's good for renewables; they're good for all technologies. And really, whether renewables succeed or fail is not a function of a FERC order. It's a function of their costs and their competitiveness. And I think they're already reacting competitively as one would expect, and we don't know what the new and improved technology coming down the road will be. So that's why we have markets, to provide incentives to people to have creative solutions. I don't think there's a plausible path to a short-term increase. And the longer-term increase will depend on the competitiveness of renewables. And one last point on that, which is that I think that if the states need to continue to subsidize what's clearly an uneconomic resource — for example in the short term, like offshore wind — that they're better off doing that directly. And even if it doesn't clear in the capacity market, [they're] better off doing that directly than they are undoing markets overall and undoing capacity markets in order to pursue one particular technology.

RTO Insider:

Great Joe, thank you very much. Let's call up another poll question: Do you think MOPR is vulnerable because it treats federal subsidies differently than state subsidies?

All right, 47% yes, 34% no.

Let me come back to you, Todd. In your rehearing request, EPSA suggested that changes to the existing FRR rules may prove necessary to address 'latent defects.' Can you elaborate on what changes you have in mind and how they're likely to effect state efforts to use the FRR option?

Todd Snitchler, EPSA:

I think the question, Rich, is more around is there in the order, language that would require that there be changes? I mean the Tariff

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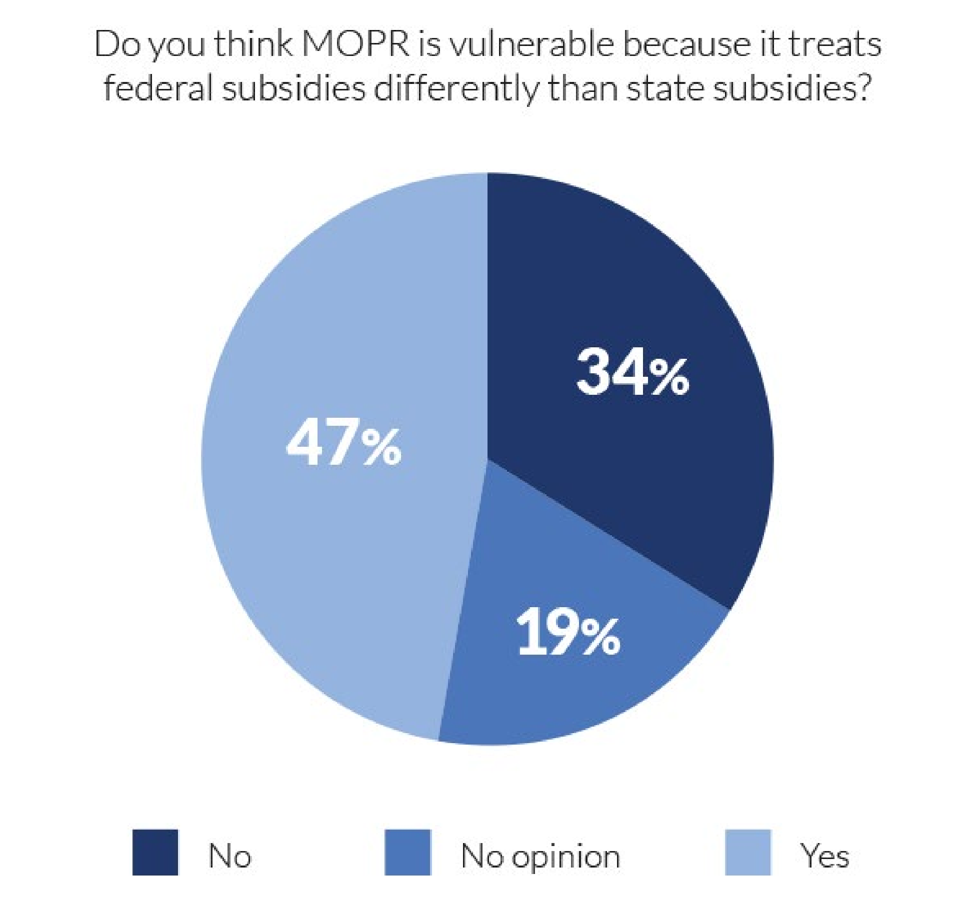

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language and provisions are already there and so there's already a demonstrable process if parties want to pursue that as an avenue to make an exit. And so, I'm not sure why there needs to be the rush in certain states to try and have some other mechanism to allow them to do that. So, I think it's a question of trying to brighten up and define the lines around ... what's required to actually do so. So, I think it's more of an open-ended question to try and get some clarity around what is actually the issue. And are further changes required? Because it's already in the tariff. It's been there for many years. And if entities want to try to use that as a vehicle, they're certainly in a position to do so.

RTO Insider:

Right, thank you. Rob, let me let you weigh in on the issue of FRRs because you've taken issue with Joe's analyses, at least the first two. I'm sure you probably haven't had a chance to look at the New Jersey one yet but why do you think he's wrong?

Rob Gramlich, ACORE:

I did look at the [New Jersey analysis]. They all use the same method. I mean, I think it is useful for Joe to provide a structure in all the data he has access to, to state policy makers. I just think the particular scenarios chosen are not useful to the questions that I'm hearing states ask. So, I guess I would wonder from Joe if he's willing to allow states to pick some of their own alternative assumptions and for him to crank out the number. I mean there's a couple of obvious things that everybody I've spoken with at the state level see as glaring inconsistencies with what they're considering doing. One is: Why [did the analyses assume] they automatically just pay the higher net CONE [cost of new entry] times B price? I mean that's half of the scenarios in each of those three state analyses. That's just assuming the answer that the price is higher and voila the cost is higher for consumers. I mean, that's not really interesting to them.

The other obvious flaw or at least difference from what states are thinking about is why are generators outside of a capacity zone paid more than they would get in the PJM auction? There's no reason an FRR needs to be designed to pay more than a competitive price. So, I don't know that states would be designing an FRR to do that.

So, I'm not pro or anti-FRR, and nor is ACORE. And I think there are probably very good and very bad ways to design an FRR. But I don't think these scenarios that have now been released in three different state reports are very useful to what the states are trying to consider.

RTO Insider:

Great, thank you. I knew you were probably biting your tongue there, so glad you had a chance to weigh in. Let's ask one other question regarding the appellate review: Do you think MOPR is vulnerable on state, federal jurisdictional grounds? That is, that it interferes with state authority over generation.

All right, 56% say yes, 34% say no. Kind of similar to the last results, which is interesting because the first question when I asked was more split, with people thinking the order would survive intact. So, people are parsing this in a variety of different ways.

We have some questions from the audience that I'd like to get into here. We have one from Robert Sweeney. It says: With some states considering leaving PJM and PJM unable to come up with amicable solutions, does this put PJM at risk of its own survival, given FERC has the authority to rescind the order that created it? Anybody want to weigh in on that?

Rob Gramlich, ACORE:

I'll jump in and say — since I'm one of the big anti-MOPR voices here and at times, criticized PJM — I sure hope everybody stays in PJM for its energy market and transmission planning benefits. Those are necessary and critical for a clean energy future. Whether states, utilities or individual customers peel out of the capacity market, I think is a wholly different question. And I think there are ways to actually promote competition, where you get many buyers and many sellers as an alternative to this sort of a single buyer capacity procurement, which is not really a market, it's a construct.

Kathleen Barrón, Exelon:

Yeah, Rich, I could chime in on that one to agree with Rob but just to add another point and to give FERC a little bit of credit here. Which is, I think they understood that, but the question he's asking is FERC going to change its mind if people start withdrawing using the FRR option? And I think the answer is no. I mean I think they explicitly contemplated that, as Todd said, the FRR provisions have been in the Tariff since the beginning of RPM. They've been used nine times; they are an option. You could use them to design a bad FRR, as Rob said, or you could use them to design a good one. But they're there and they're the option if states do not want to have to live under a MOPR regime. But they can still stay in, have the benefits of economic dispatch, reliability planning and the like and keep the fundamental core purpose of PJM intact.

IMM Joe Bowring:

This is Joe. I believe that PJM will survive. Whether you want to call it a market is another question. It's not a market if it doesn't reproduce itself, if it does not sustain itself through a capacity market. But still, it still would be a lot better than going back to cost of service regulation without an integrated energy market. So, I don't think it's going to go away. FERC has decided in the past that companies are allowed to leave RTOs; whether they continue to keep that policy in the future, remains to be seen. But FRR doesn't mean leaving PJM, it simply means leaving the capacity market.

RTO Insider:

Great, thanks Joe. We are just about out of time but we're going to run a little bit longer — if those of you can stay with us for a few minutes — since our opening statements ran a little long, Merry why don't you call up our last polling question, which is on the subject of FRRs. And that is, is an FRR a good or a bad idea for states as an alternative to the expanded MOPR?

All right. About 41% say good idea, 32% bad idea and a lot of people don't really know at this point.

So, I think that's where we'll leave that subject except let me ask one question to Joe. Scott Senchak asked the question: If the FRR elections push prices higher in states that elect the FRRs, what will prices do to the non-FRR regions in PJM? And I think the answer to that is it varies, but Joe, why won't you elaborate on that?

IMM Joe Bowring:

Sure, as a general matter, they reduce prices elsewhere. It really depends on the dynamics. So, take ComEd for example. The first one we did; we show the impact on RTO prices being substantially negative. That is, it would make the prices substantially lower if ComEd decided to become an FRR entity. The reason for that is that they would import less capacity from outside, use more internal capacity. Thousands of megawatts in ComEd didn't clear in the BRA [Base Residual Auction]. So, it really depends on the extent to which the zone, the LDA [locational deliverability area], had previously imported. But in general, I think with only one exception, we've seen that the creation of an FRR suppresses the price, makes the price lower elsewhere in the RTO.

RTO Insider:

Right, thanks for that clarification, Joe. We have a question here from Will Niver, who

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says: I can't claim any expertise here, but I keep getting caught up on the meaning of subsidy. MOPR seems to be focused on the production tax credit, investment tax credit, RPS, etc. But federal and state governments have always provided subsidies for cheap energy. Why wouldn't the direct and indirect subsidies in the U.S. tax code designed to support domestic fossil fuels count here? I'm thinking specifically of the intangible drilling cost reduction and percentage depletion.

Many people have raised that issue, including Commissioner Glick. I don't know if anybody wants to weigh in here but that certainly is one of the questions that's likely to be brought up on appeal. Anybody want to weigh in on that?

Kathleen Barrón, Exelon:

I can chime in, I think. I think it's a fair question, as you point out, Commissioner Glick has said it time and time again, as have other commissioners before him. Chairman [Norman] Bay, for example. But getting back to your question about the appeals, I think it's relevant to that question because the MOPR that we have now isn't just targeted at credits to clean energy. It's only focused on state credits to clean energy. Federal tax credits, investment tax credit, PTC, even to clean energy are exempted. So, I think FERC, my sense, is going to have a little bit of a hard time explaining that to the court of appeals. There is no basis given in the order for the logic behind that and/or at least no basis that I think is going to be compelling. So, I think it goes to that question in particular of the sustainability of the policy on appeal. Putting aside the broader questions of the fact that intangible drilling and other subsidies do have an effect on the ability of an asset to bid low in the market.

RTO Insider:

FERC said they didn't want to stand in the way of Congress's directives. Go ahead, Todd.

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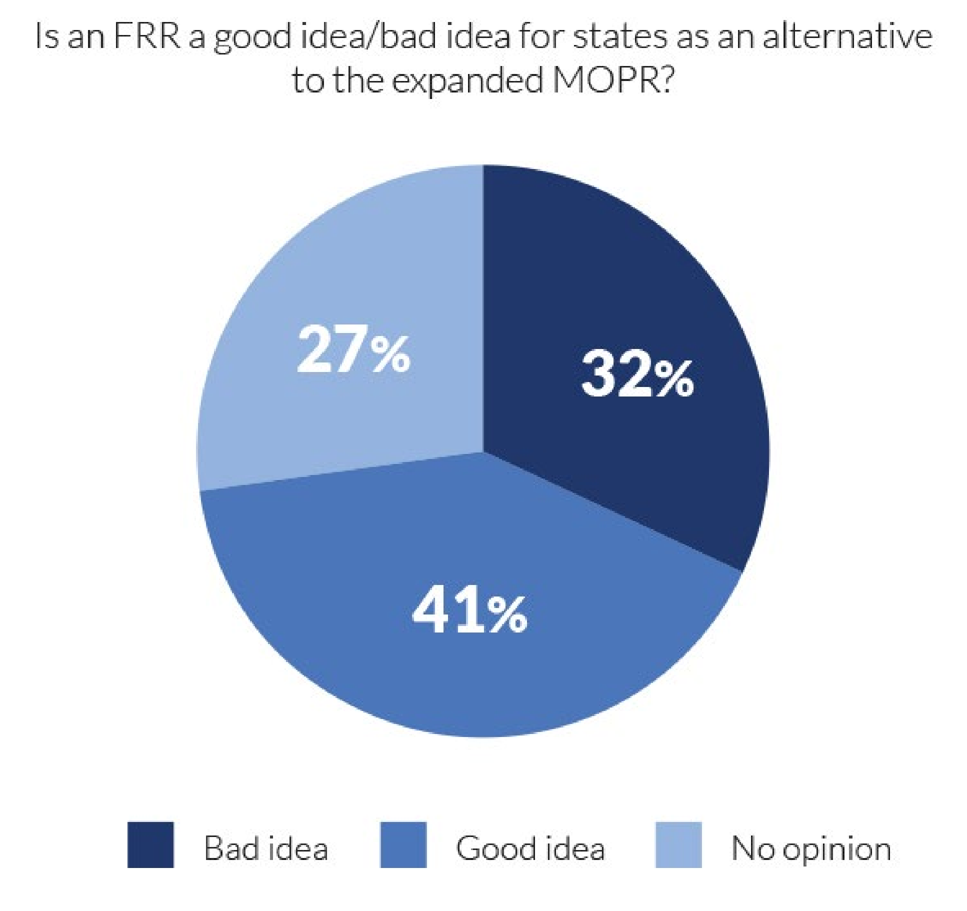

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Todd Snitchler, EPSA:

I just wanted to add a little bit from the intangible drilling credit and some of the tax code provisions. I think you walked on a very slippery slope when you move N minus one minus one into what some input costs could be and how the tax code may treat certain items versus others. As opposed to dollars that leave from consumers' pockets and go directly into the pockets of a receiving entity for a zero-emission credit or some other type of subsidy or state support payment. And so, I think there is a pretty bright line difference between something that's two steps removed and in the tax code versus something that is a direct payment from one entity to another.

IMM Joe Bowring:

I would just add that given that the nuclear industry as well as the oil and gas and coal industries who look very different, they had not been supported, subsidized, in some cases, effectively created by the federal government. That's all true. There've been very significant impacts of federal subsidies over time. I think what the MOPR order is trying to do is focus on state actions versus federal actions and it's a reasonable place to focus. We will see what the court says, as you pointed out.

Rob Gramlich, ACORE:

And I'll just say that the effect of that, both that distinction and Todd's, ends up targeting renewables. Intentionally or not, it's an unfair outcome.

RTO Insider:

Great. Well one hour hardly is enough time to tackle all of these issues. If you haven't had your fill, you can click into the [Market Implementation Committee] meeting [on MOPR], which is perhaps still going on. They were going to be discussing MOPR all afternoon. But before we wrap up, let me just give you all a chance to make one final point. If you'd like, an issue that either, maybe a question I didn't ask or a point that you didn't have a chance to make thus far. Jim, why don't you start off?

Jim G. Davis, Dominion:

I think this is a great discussion, I think it's an important one to have and we will see what comes out of the commission in terms of a final order as well as the courts, I think at this point, in terms of the courts, it's somewhat speculative of what will happen. And I think it goes to our point that ... As a decision comes down this year, we're going to be on a compressed timeline for the auctions and decisions will have to be made much quicker than what they have

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been in the past. I'll just reiterate what we've been advocating for is just clear rules that can be implemented so that participants can actually make those decisions as to how to participate. Whether it's the states enacting laws or if it's the market sellers. Making a decision whether or not to retire a resource or make the capital investment in those resources. I think all these things will have to be considered and we'll find out soon enough. So, appreciate the time. Thanks.

RTO Insider:

Thanks, Jim. Kathleen, how about you? Any parting thoughts?

Kathleen Barrón, Exelon:

Just one, we talked a little bit about the various, the value of remaining in RPM versus withdrawing and using the FRR option for states that want to continue to pursue their clean energy policies. But just focusing on the clean energy community and why there is additional value in the FRR option. And you got to this a little bit at the beginning, Rich, with the continuing battles over RPM market design. Two of the things that we didn't touch on today that I hear coming from the clean energy community. One is this sort of structural cost savings opportunity by using the 16% reserve margin that an FRR zone can use versus what customers are paying for now and the continual concern about overpaying for excess capacity that's unneeded. States can solve that problem using the FRR construct. And then the other point is on Capacity Performance penalty mitigation, and the physical option that's available in the FRR construct for resources to pool for purposes of Capacity Performance penalties is widely seen as something that will encourage more renewable participation in the market. Granted that they won't be able to participate at 100% of their capacity, they will still be derated.

But they will be able to get the value of that derated capacity in the FRR construct where many of them don't in today's version of RPM. And then I guess I'll just close on absolutely to the extent folks want to continue talking about durable solutions. I'm not sure we really got to that today but that's a worthwhile thing to keep doing. I think there's a lot of folks, including PJM as was pointed out, who don't think this is a durable solution. But we welcome that conversation and as long as we are mindful of our emissions reduction goals and achieving them in a way that's cost effective for customers, we should do that work.

RTO Insider:

Excellent, thank you very much. Todd, why don't you weigh in next.

Todd Snitchler, EPSA:

Thanks, Rich. The only thing I'd mention that we didn't talk about is the need to run the auction. And we have been very consistent for time immemorial on the importance of actually running an auction. I think it becomes even more important, based on some of the conversation we've had here today, that we get the auction run so that policymakers and entities that are investing in their resources, whether they're new or existing, have real-time data that's accurate and allows them to make informed decisions instead of speculative decisions, which I think creates all kinds of room for mischief or for people to not be able to make any decision. And that is a bad outcome across the board. And so, the sooner that we can see an auction be run and then a subsequent auction be run and get back onto a normal schedule, the better it will be for all market participants. Because it'll give them the information and the data points that I think are needed in order for us to make some very important decisions about how the grid is going to both exist in the short term but where it's going to evolve in the longer term.

RTO Insider:

Great, thank you, Todd. Rob, your final thoughts?

Rob Gramlich, ACORE:

Sure, I'll just say that if any resource wants to sell into the capacity market, it should be able to and get paid for its capacity value. That's just a fundamental, basic thing that MOPR violates. And so, we need to get back to that basic principle and just like if you sell any other product into a wholesale market, that resource should get paid for providing that product. So that's all I think renewables are asking for and I'm hopeful that we can eventually get back to that sort of basic structure.

RTO Insider:

Great. Well, Joe, I'm going to ask you to have the more or less final word here. I'm not exactly sure what's top of mind for you, but I know that in the past, you've talked about other problems with the capacity market beyond the issue of MOPR, and you've been talking about some of them for years, I know. What's your outlook, going forward?

IMM Joe Bowring:

Sure. The MOPR debate I think has matured. Kathleen pointed out it's been going on for a long time and I think it has, I think it's evolved, I think it's to the point where I think FERC took it to a logical point. They drew the line and drew it comprehensively. Now is a time for decision. However it turns out, hopefully we'll all move past it. I don't think there is a fundamental principle that subsidized resources get to compete heads up with non-subsidized. So, there's a decision needed. But we also have been pointing out and Kathleen [noted] a minute ago that there have been issues with the capacity market for some time. And if PJM and FERC had addressed them when we raised them, some of the current issues would not have arisen, for example over-procurement, we've been talking about over procurement for years. That's certainly an issue we've been talking about market power and the capacity market. We've been talking about the role of DR, the treatment of imports, whether or not they're truly substitutes for internal resources. And not [only] in the capacity market but overall in the markets, a lack of a carbon price.

So as Kathleen said, we're not sure we need another conference, but it's a little ironic to want FERC to do a carbon price when in fact what we think the RGGI model makes more sense. That is a state driven, if the states truly want to do something about carbon then the carbon price would be a great way to go. And probably last but not least, we agree that no matter what the decisions are, there's 150,000 plus megawatts of capacity out there that relies on markets or relies on PJM to continue running markets. It's essential that the markets go forward and the rules will be what they are, the decisions will be what they are and the markets will adapt. No matter what the ultimate decision is, hopefully it'll be a decision which we can all incorporate in the rules and move forward and figure out a way to have as competitive markets as possible, for the benefit of customers. Thanks.

RTO Insider:

Great, thank you Joe. Thank you everybody. Thank you both to our participants and our audience, who asked some very good questions. Sorry we ran out of time for those. But I do encourage you to send us your ideas on other issues you think we should tackle in a future webinar. This is something that seems to be especially attractive under the circumstances that people get to get out and communicate, even virtually. And so, we will be planning additional webinars in the near future. So, thank you to all of you, from all of us at *RTO Insider*. And stay healthy. ■

Commenters Weigh in on PJM MOPR Compliance Filing

Changes Sought on Auction Timing, Floor Prices, Unit-specific Rules

By Rich Heidorn Jr.

More than two dozen companies and coalitions filed responses to PJM's March minimum offer price rule (MOPR) compliance filing last week, taking issue with the RTO on auction timing, floor prices, unit-specific rules and self-supply exemptions (EL16-49).

PJM made the 683-page filing in response to FERC's December order expanding the MOPR to new and existing state-subsidized resources with exceptions for existing demand response, energy efficiency, self-supply and resources receiving payments under renewable portfolio standards. (See *PJM Makes MOPR Compliance Filing*.)

Below is a summary of the issues raised in the comments and protests filed last week.

Wind farm near Altoona, Pa. | © *RTO Insider*

Auction Timing

Commenters weighed in on both sides of PJM's proposal to hold the Base Residual Auction for delivery year 2022/23, six and a half months after a final compliance order but no later than March 31, 2021.

The Electric Power Supply Association, PJM Power Providers (P3) Group, NRG Power Marketing and Calpine — whose complaint led to the December order — all called for an earlier auction.

"For its part, EPSA is deliberately refraining from wading into the details of the compliance filing in order to focus on the importance of conducting the 2022/23 BRA as soon as possible," it said.

PJM proposed delaying the auction to as late as March 2021 if it is requested by regulators in a state that approves legislation before June 1 opting out of the capacity market for a fixed resource requirement (FRR).

EPSA noted that FERC's April order rejecting rehearing of the December ruling requires PJM to make a second compliance filing June 1. "Realistically, even assuming a shortened comment period for the second compliance filing and a lightning quick turnaround on the commission's part, it is hard to see the commission issuing an order earlier than July 1, 2020, which, under PJM's schedule, would have the 2022/2023 BRA being conducted in mid-January 2021," EPSA said. That would leave a forward period for the BRA of only 14 to 16 months, versus the three years under the Reliability Pricing Model's (RPM) normal schedule.

"EPSA recognizes that PJM's request may be moot if no state enacts FRR-enabling legislation by the end of this month, but the commission will undoubtedly be asked to extend the June 1, 2020, deadline or to deem it satisfied by something less than legislation 'enacted' by that date," Calpine added. (Indeed, New Jersey regulators said the extension should also accommodate state regulatory processes. See below.)

P3 said the yearlong delay in the 2022/23 auction has already "thwarted" decisions on investments and maintenance; "projects have not been financed or refinanced" because of the lack of forward price signals.

"The delay … is well beyond the pale of acceptable. For the sake of suppliers, consumers and the sanctity of the PJM wholesale market, resumption of these auctions must become a priority for the commission and PJM," it said. "PJM and the commission continue to look to each other to 'make the call' on the timing of the next auction. P3 urges the commission to end this back-and-forth and provide specific direction to PJM so these auctions can resume."

> **"For the sake of suppliers, consumers and the sanctity of the PJM wholesale market, resumption of these auctions must become a priority for the commission and PJM."**
>
> —P3

P3 and NRG questioned whether PJM needs more than six months to prepare for the next auction, noting it proposed a 4.5-month time preparation period the subsequent BRAs.

P3 urged the commission to "settle the issue of the definition of a state subsidy" and finalize net cost of new entry (CONE) and avoidable-cost rate (ACR) values in its order on the compliance filing and give capacity resources 21 days to determine whether they are subject to the MOPR. "For those units that are considered subsidized and not eligible for an exemption, PJM and the [Independent Market Monitor] could immediately commence the unit-specific review process for those units that elect that process.

"PJM should not be idly waiting for the commission's second order on compliance.

Moving Ahead on MOPR

Instead, the commission should direct PJM to commence its auction preparation following its approval in this compliance proceeding and then direct PJM, as part of the second compliance process, to derive a timeline shorter than six and a half months," P3 said.

"Suspension of market milestones in deference to states embroiled in special interest lobbying does not simultaneously freeze all other factors that contribute to the economics of supply and demand of a 180,000-MW market, which serves 65 million customers," NRG said.

The company said it has spent more than $500 million over the last six years to modernize and add environmental controls to its Illinois fleet "based on a market structure that was regularly generating price signals while at the same time enhancements such as Capacity Performance were being incorporated into PJM's capacity construct."

"Absent RPM price signals, NRG will blindly face investment decisions for commitment years that are rapidly approaching. Environmental regulators, both state and federal, will press on with deadlines that could require near-term capital spending for compliance with regulations such as the Effluent Limitations Guidelines for Steam Electric Generating Facilities and Coal Combustion Residuals."

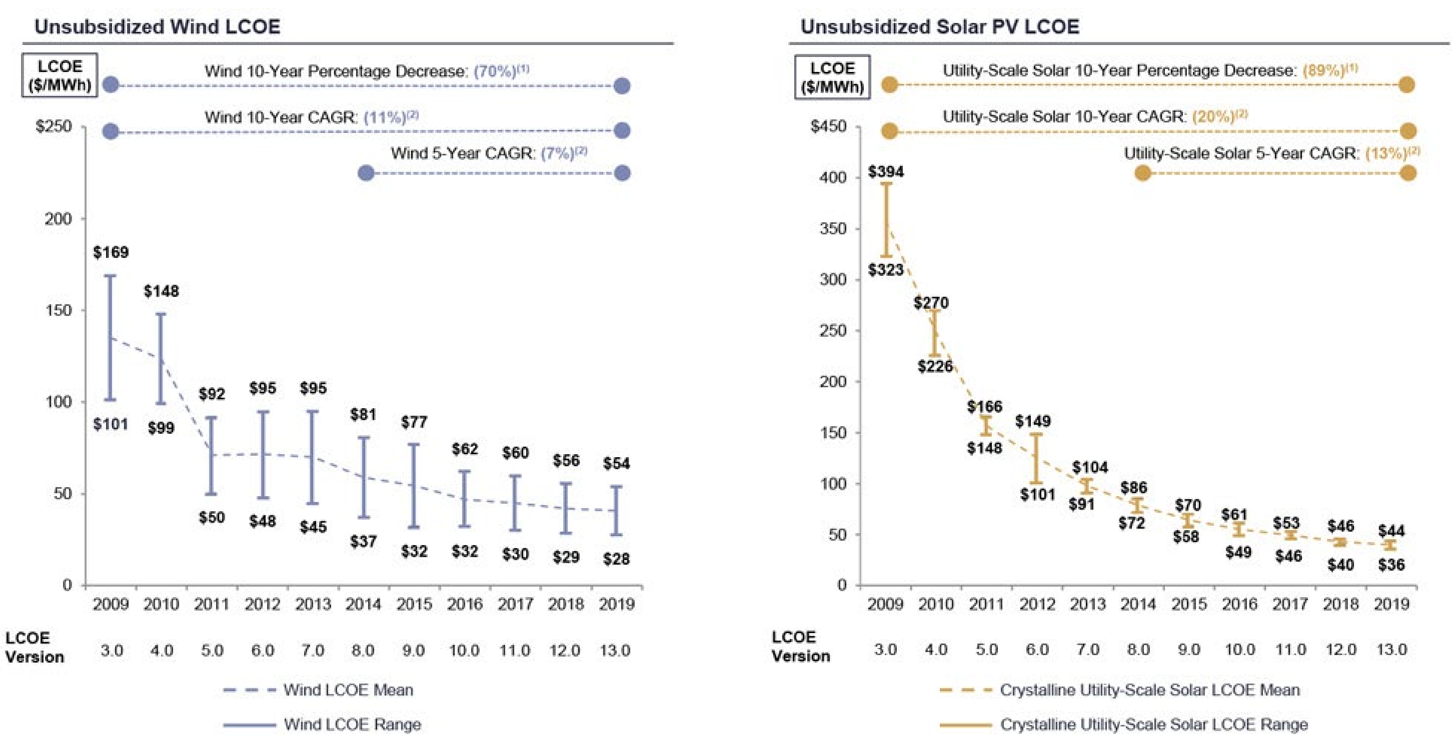
NRG and P3 also noted that utilities have had to adjust their default procurement programs because of the delay.

FERC Chairman Neil Chatterjee (left) and Commissioner Richard Glick chat before the start of the commission's open meeting in September 2019. | © *RTO Insider*

New Jersey electric distribution companies told the state Board of Public Utilities that bidders in the state's Basic Generation Service default procurement program were likely to include risk premiums in their bids and that some potential bidders may not participate, "which could result in higher prices in the auction," NRG said.

State regulators, consumer advocates and environmental groups argued in favor of the Organization of PJM States Inc.'s (OPSI) call to delay the auction until as late as May 2021, several of them noting that the coronavirus pandemic caused the suspension of state legislative sessions. The Maryland General Assembly adjourned March 18, failing to complete its full session for the first time since the Civil War.

"With the commission's recent determination that capacity resources indirectly benefiting



In the last decade, the levelized cost of energy (LCOE) for utility-scale solar has dropped by 89% and the LCOE for onshore wind has declined by 70%. | *Lazard*

Moving Ahead on MOPR

from state default service auction process are also subject to the MOPR, the impact of the MOPR on state policies has become only more disruptive, further supporting OPSI's request," the Natural Resources Defense Council, the Sierra Club and the Sustainable FERC Project said.

"The FRR alternative is not the only step that states might need to take to protect consumers and state policies from the harm of the MOPR," the environmental groups said. "States may also need to revisit the structure of their default service auctions, the manner in which state objectives relating to generation are pursued or budgets for bill payment assistance."

Exelon — which is supporting legislation to create an FRR in its Commonwealth Edison territory in Northern Illinois — also endorsed the May date. (See *Clock Ticking on Exelon Illinois Nukes Under MOPR*.)

In a joint filing, consumer advocates for New Jersey, D.C., Maryland, Delaware, Illinois and Pennsylvania said the auction schedule should allow for a "complete load forecast similar in scope and depth" to those used in prior auctions.

"The ongoing COVID-19 pandemic and attendant reduction in economic activity only highlight the need for regular updates over the coming BRAs," the advocates said, noting that PJM's load has dropped by an average of almost 8%, with peak impacts as high as 15%. "These significant reductions in demand will be all the more impactful because the time between the next four BRAs and the actual delivery year will be reduced from three years to as little as one year. In other words, updated load forecasts will reflect not just the long-term outlook but short- and medium-term operating conditions."

The New Jersey BPU said PJM's proposed extension should not be triggered only by FRR legislation. "Implementation of the FRR alternative could also involve efforts by state regulators and state regulatory processes — even where no change in legislation is required," it said. "The [BPU], for example, has initiated an investigation into resource adequacy alternatives, which includes exploration of its own statutory authority to implement these changes without additional legislation."

Demand Response

The PJM Industrial Customer Coalition called for Tariff changes to clarify that neither year-to-year fluctuations in customer consumption nor changes in state subsidy levels should cause an existing DR resource to lose its MOPR exemption.

The ICC said its proposed changes would "clearly distinguish between capability fluctuations that occur as a result of year-to-year modifications in consumption and the 'step-jumps' associated with uprates to physical capacity. The former is MOPR-exempt, the latter is not."

Default Floor Prices

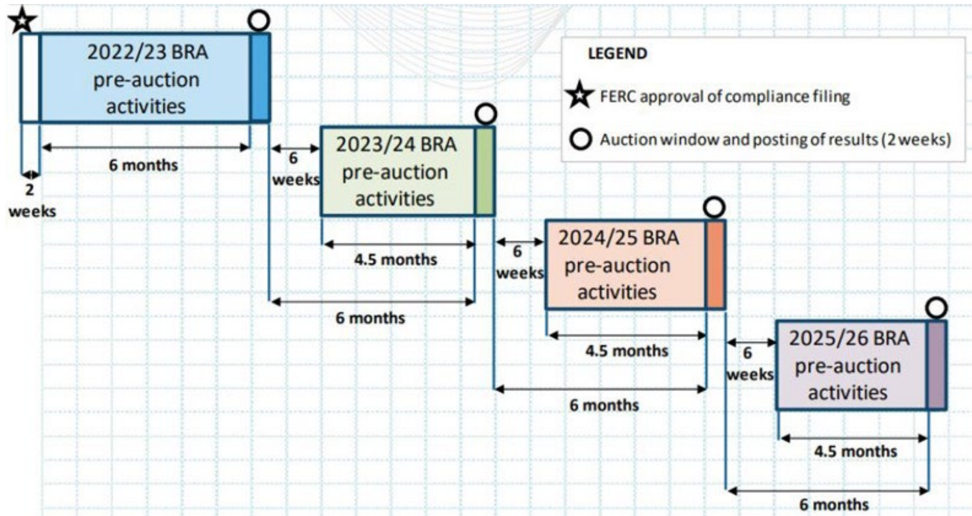
Members of the Maryland House Economic

"With the commission's recent determination that capacity resources indirectly benefiting from state default service auction process are also subject to the MOPR, the impact of the MOPR on state policies has become only more disruptive."

—Natural Resources Defense Council, the Sierra Club and the Sustainable FERC Project

PJM would seek to eliminate the first and second Incremental Auctions for delivery year 2022/23 if the Base Residual Auction is not held until December 2020. | *PJM*

Moving Ahead on MOPR



Proposed capacity auction schedule | *PJM*

Matters and Senate Finance committees, which oversee state energy policy, complained that the default floors proposed by PJM will likely prevent many renewable resources, especially offshore wind and storage, from clearing the auction.

"The mere possibility that renewable energy and storage projects will be able to obtain resource-specific offer price floors allowing them to clear the auction does not allay states' concerns," they said. "The outcomes of such an idiosyncratic and opaque resource-specific offer floor process are unpredictable and therefore cannot be relied upon by state lawmakers that need to understand the costs and benefits of different legislative proposals."

The Pennsylvania Public Utility Commission took issue with PJM's use of "speculative" cost adders, saying MOPR floor prices "should not be 'maximum offer prices' but prices that reflect actual costs of competitive entry."

It said PJM's traditional price escalation factors are at odds with the declining costs of solar, batteries and onshore wind, noting new crystalline solar PV resources' nominal levelized cost of energy have declined from $359/MWh to $41/MWh since 2009.

For onshore wind, PJM proposed using the Energy Information Administration's 2019 value of $1,677/kW, which the PUC said is 14% higher than any alternative published value and outside Lazard's range of values ($1,100 to $1,500/kW).

PJM's gross CONE value for onshore wind assumes a 17-by-2.8-MW configuration (about 50 MW). "However, PJM's current interconnect queue as of May 6, 2020, for onshore wind projects shows an average project size of 205 MW over 80 projects," the PUC said.

"For newer declining cost technologies, annual price adjustments should be adopted to reflect current and projected nominal costs at the time of development," it said.

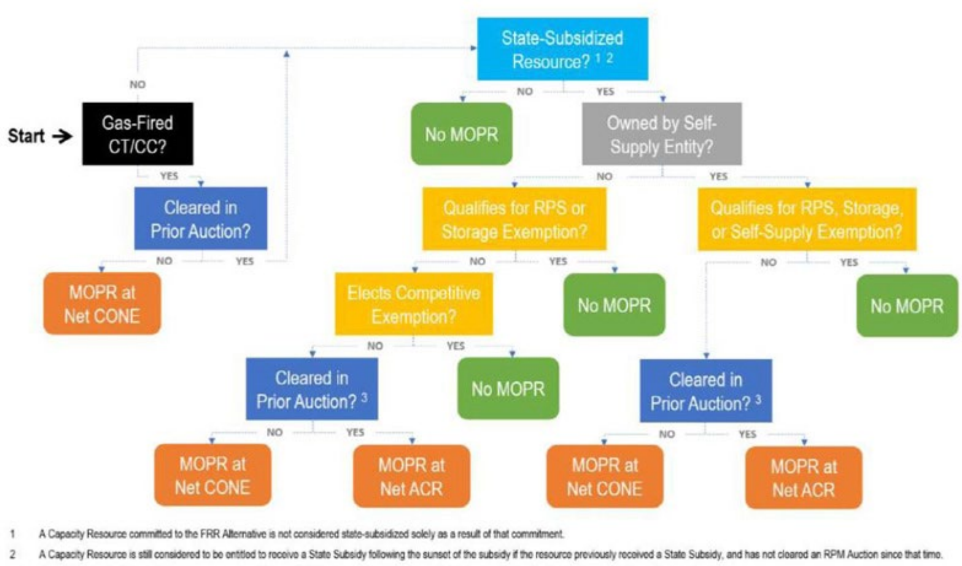
Unit-specific Rules

PJM's proposal for unit-specific exemption requests also drew criticism, with some calling for more flexibility and Calpine calling for rigorous vetting.

"The unit-specific review process must be carefully conducted in order to ensure that it does not defeat the purpose of offer-floor mitigation," Calpine said. "PJM and the IMM should vigorously review any such submissions to ensure that the seller has adequately demonstrated that it is reasonable to assume an asset life of more than 20 years for the specific resource at issue. As another example, to the extent that a seller relies on 'long-term power supply contracts, tolling agreements or tariffs on file with state regulatory agencies' in order to support its projected energy and ancillary services markets revenues, PJM and the IMM should take pains to ensure that such contracts, agreements or tariffs are not disguised state subsidies."

OPSI and the Pennsylvania PUC complained that although PJM said it would allow evidence of a longer than 20-year asset life, it proposed standardizing the other five financial modeling assumptions used to calculate resource-specific offers: nominal levelization of gross costs; no residual value; all project costs included with no sunk costs excluded; use of first year revenues; and weighted average cost.

"While each of the assumptions may have a material impact on the calculation of the offer floor, PJM only proposes flexibility with respect to the 20-year unit life element," OPSI said. "If a resource owner maintains its financial records using real levelized costs rather than nominal, or can document residual value for its unit, or uses a different protocol for sunk costs, the resource-specific cost review



MOPR eligibility flow chart | © *RTO Insider*

Moving Ahead on MOPR

process for the purpose of calculating MOPR floor prices should permit that flexibility to be reflected."

State Procurements

Calpine also called for tightening PJM's proposal for exempting state default service procurements.

It said the state subsidy definition should only exempt "nondiscriminatory, competitive, and fuel- and emissions-neutral state-directed default service procurement programs."

"Without this modification, the proposed definition could allow a state to evade the MOPR by requiring a procurement process that is nominally competitive and neutral with respect to fuel type but that is structured in a way that will exclude potential competitors for the benefit of favored resources," Calpine said.

Self-supply

Dominion Energy called for broadening the competitive exemption to include self-supply entities.

"Self-supply entities that are vertically integrated utilities, such as Dominion Energy Virginia, currently own and are developing new solar resources [that] are not part of its rate base and whose costs are 'ring fenced' and not recovered from ratepayers," it said. "As a result, these resources are not receiving a 'state subsidy' as defined by the Dec. 19 order even though they are owned by a 'self-supply entity.'"

OPSI called for exempting all existing bilateral contracts, saying PJM's proposal discriminates against load-serving entities in restructured states.

The organization said it supports PJM's proposal to exempt bilateral contracts where the buyer is a self-supply entity but said the RTO's "justification for the exemption applies equally to other, bilateral contracts of non-self-supply entities."

"This exemption should be extended further to include enforceable supply purchase contracts entered into by non-self-supply entities entered into prior to Dec. 19, 2019, in reliance upon then-existing commission guidance. Load-serving entities in restructured states should not be precluded from using the business arrangement provided for self-supply entities in PJM's compliance filing."

Voluntary RECs

The Advanced Energy Buyers Group, a coalition of large energy users, said FERC should order PJM to create "an additional pathway" for capacity resources that sell a portion of their output to a voluntary purchaser and a portion to a compliance purchaser to avoid applying the expanded MOPR to the voluntary transaction.

"PJM's compliance filing would subject such projects to the MOPR in their entirety. That result could also limit the market for voluntary purchases of renewable energy by forcing buyers to purchase the entire output of a project to avoid the MOPR, which many buyers may not be in a position to do," the group said.

Subsidy Determinations

The American Wind Energy Association, the Solar Energy Industries Association, Advanced Energy Economy and the Solar Council, filing jointly as "Clean Energy Associations," asked the commission for assurances that capacity market sellers "will be allowed to rely upon guidance from PJM and the IMM" in determining which state and local programs constitute state subsidies. They urged FERC to "direct PJM to create an ongoing process for market participants to timely obtain such determinations."

The NRDC, Sierra Club and Sustainable FERC Project called for a transparent process, including a public list of which policies have been determined to be subject to MOPR; a process for parties to submit a policy for consideration with timelines for the decision-making process; and a process for determinations to be clarified or challenged at FERC.

"Absent clear reporting requirements, expanded discovery powers for PJM and/or the Market Monitor, and possibly some form of safe harbor for resource owners, uncertainty regarding the ultimate purchaser of power is likely to result in over mitigation of resources that do not receive a subsidy but are unable to verify they do not," the groups said.

"This kind of uncertainty, case-by-case analysis and lack of transparency or oversight is likely to result in inconsistent application of the MOPR in a manner that introduces discriminatory treatment of resources."

American Electric Power complained that PJM's proposed MOPR exemption for voluntary bilateral transactions was unduly restrictive. FERC said voluntary bilateral transactions were not state subsidies but "permissible out-of-market revenue."

"PJM appeared to limit the applicability of the commission's holding in its March compliance filing by only addressing its treatment of bilateral transactions in which one party is a self-supply entity," AEP said.

Accounting for Federal Tax Credits

AWEA and SEIA also said that while PJM properly proposed accounting for the federal investment tax credit in default gross CONE calculations for wind and solar resources, it "does not expressly provide comparable treatment for other types of federal subsidies," such as the federal production tax credit. ■

Zone	Solar PV (Tracking)	Solar PV (Fixed)	Onshore Wind	Offshore Wind	Battery Energy Storage	Demand Response Generator	2021/2022 BRA Clearing Price ($/MW-day)
APS	$165	$357	$994	$3,116	$1,042	$254	$140.00
BGE	$135	$333	$869	$2,999	$977	$254	$200.30
DPL	$180	$374	$955	$3,092	$994	$254	$165.73
PEPCO	$147	$343	$909	$3,038	$1,001	$254	$140.00

Default net CONE ($/ICAP MW-day) | *Maryland legislators*

Moving Ahead on MOPR

PJM Monitor Finds Capacity Exit Costly for NJ

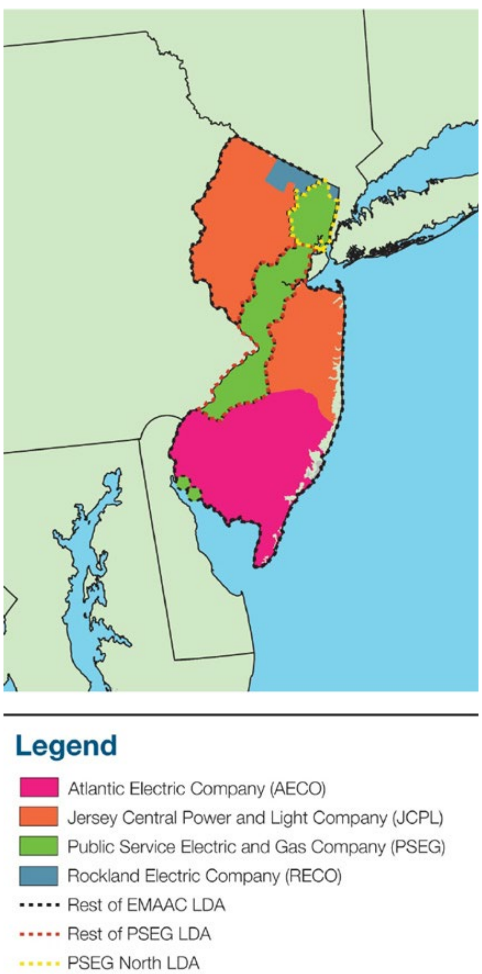
RTO Briefs Stakeholders on Upcoming Compliance Filing

By Rich Heidorn Jr.

PJM's Independent Market Monitor released a report Wednesday concluding that New Jersey ratepayers would likely see costs increase if the state left the RTO's capacity market and instituted a fixed resource requirement (FRR).

The New Jersey Board of Public Utilities opened a docket March 27 to investigate whether remaining in PJM's capacity market under the expanded minimum offer price rule (MOPR) will impede Gov. Phil Murphy's goals of 100% clean energy sources in the state by 2050 (Docket No. EO20030203). Comments are due this Wednesday.

The BPU acted in response to FERC's Dec. 19 order that expanded the MOPR to new and existing state-subsidized resources. The order granted exceptions for some existing resources: demand response, energy efficiency, self-supply and resources receiving payments under renewable portfolio standards.



MISO's March 2019 Board of Directors meeting in New Orleans | © *RTO Insider*

The order could prevent New Jersey nuclear plants receiving zero-emission credits (ZECs) and future offshore wind generators from clearing the capacity market, leaving ratepayers paying twice for some capacity. Unless the order is overturned on appeal, New Jersey's only alternative to the PJM capacity market is to provide its own capacity under the FRR.

Monitoring Analytics' *report* concluded that a statewide FRR would increase costs by almost 30% if prices were at the PJM offer cap of $235.42/MW-day but only 2.4% if prices equaled the $186.16/MW-day weighted average price for the state in the 2021/22 Base Residual Auction held in 2018, the most recent auction.

Using similar assumptions, the Monitor found that ratepayers in an FRR for the PSEG locational deliverability area (LDA) would pay 6.4 to 27% more. Those in an FRR for the JCPL zone could save 2.1% or see prices rise by 28%. (The Monitor did not provide separate analyses for the AECO or RECO areas, which represent only 15% of the state's load.)

"Based on the analysis, the creation of a New Jersey FRR, a PSEG FRR or a JCPL FRR is likely to increase payments for capacity by customers in New Jersey," the Monitor said.

The Monitor's analysis was requested by Stefanie Brand, director of the New Jersey Division of Rate Counsel.

The BPU said Wednesday "it is premature to comment on the IMM's report or anticipate what the results of the investigation may be."

"Staff has an obligation to review the comments filed in the docket and take any necessary action to continue the investigation (through further requests for comment, technical conferences or hearings) before making recommendations for the board's consideration," the BPU said.

The Monitor said an FRR creates market power for the few local generation owners from whom generation must be purchased to meet reliability requirements. New Jersey has 15,005 MW of unforced capacity within its borders, 4,711 MW less than the 19,716 MW needed to meet its FRR reliability requirement.

"All participants in the New Jersey, JCPL and PSEG FRRs fail the one- and three-pivotal-supplier test, which reinforces the conclusion that there is structural market power in each case," it said.

Because of the impact of market power, "even the higher estimates of the cost impact to the customers of New Jersey from the creation of an FRR are likely to be conservatively low," the Monitor said. "If New Jersey were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs."

"Our basic overall point is that FRRs are not a panacea," Monitoring Analytics President Joe Bowring said Wednesday during an *RTO Insider* webinar on the MOPR.

"FRR is a term that is really not very well defined, and the exact ratemaking process will be the result of negotiation. … There are, at the moment, no rules governing it; every state will do it their own way. But there is simply no reason to believe that this nonmarket approach … will provide the least-cost option for customers or provide incentives for renewables or for any form of energy you favor."

The Monitor's findings were similar to those of its previous *analysis* on the impact of Exelon's Commonwealth Edison in Northern Illinois leaving the capacity market for an FRR and one on Maryland's options.

Others have disputed those findings. Rob Gramlich, president of Grid Strategies, said FRRs won't necessarily raise costs because they can use a lower reserve margin than PJM. (See *PJM Monitor Defends FRR Analyses in MOPR Debate*.)

Exelon is pushing legislation in the Illinois General Assembly to switch to the FRR. (See *Clock Ticking on Exelon Illinois Nukes Under MOPR*.) And Public Service Enterprise Group CEO Ralph Izzo said May 4 that it would be "logical" for New Jersey to abandon PJM's capacity market for the FRR. (See *PSEG Turns Bullish on NJ FRR Option*.)

Both Exelon and PSEG are trying to protect their nuclear units receiving state ZEC subsidies. ■

Moving Ahead on MOPR

PJM Refining Default Service Rules Under MOPR

By Michael Yoder

PJM officials have revised some of their proposed rules for applying the minimum offer price rule (MOPR) to state default service procurements in response to stakeholder feedback.

At the Market Implementation Committee meeting Wednesday, PJM attorney Chen Lu outlined a revised definition of an "entity providing default retail service." The new definition defines the term as any entity "providing default retail service, including but not limited to a load aggregator or power marketer that enters into a contract or similar obligation with an electric distribution company to provide default electric services for retail customers who do not participate in the selection of a competitive retail provider that has been granted the authority."

Exemption Criteria

Lu also provided a revised "state subsidy definition" exempting "bilateral transactions" used to fulfill default retail service obligations from the MOPR if the state default procurement auction meets certain criteria:

- being subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a nondiscriminatory and competitive bidding process;
- does not impose conditions based on the ownership, location, affiliation or resource type — except for meeting state renewable portfolio standard requirements;
- does not require bilateral transactions to be sourced from any specific resource or resource type to satisfy retail supply obligations; and
- costs can be avoided by retail customers who elect to obtain supply from a competitive retail supplier.

Wednesday's two-and-a-half hour discussion picked up on talks at the MIC's special session May 6 over straw proposals attempting to address Paragraph 386 of FERC's April 16 rehearing order of its Dec. 19 order expanding the MOPR. That paragraph said that state procurement auctions are a form of a state subsidy because they provide a payment or other financial benefit to capacity resources that are part of a state-sponsored or state-mandated process. PJM must make a compliance filing in response to the April order by June 1.

NRC Chairman Kristine L. Svinicki tours Energy Harbor's Beaver Valley nuclear plant. Energy Harbor announced April 30 that it was awarded 18 tranches in the recent Pennsylvania provider of last resort (POLR) auction. | *NRC*

Lu said the RTO reconsidered the definitions based on stakeholders' opinions that their "potential compliance approach" was "likely too complicated and potentially unworkable." (See *PJM, IMM Present MOPR Rules for State Procurements*.)

Jason Barker of Exelon said Wednesday he was "concerned" by the new language and requested PJM consider how the selected wording would impact businesses participating in the provider of last resort (POLR) auctions. He said focusing the exemption on the existence of bilateral contracts could have major implications on most capacity auctions because some POLR auction suppliers also own generation.

"You could have the potential impact of tens of thousands of megawatts of potential supply into those auctions," Barker said. "We would certainly ask you to sharpen the pencils on that point."

Lu said the new language was proposed as another alternative after hearing stakeholder concerns at the May 6 special session and that the RTO has not finalized its decision on the issue.

Consultant Roy Shanker said he liked the new wording, calling it a "simple solution" that seemed to address concerns voiced by Sam Randazzo, chairman of the Public Utilities Commission of Ohio, at the May 6 meeting. Shanker said a simple way to look at the new language was that if the auction is asking for more than megawatts or megawatt-hours, then it's discriminatory.

"This is an efficient way to send the right signal about who you are trying to exempt," Shanker said.

Gary Greiner, director of market policy for Public Service Enterprise Group, said he was

Moving Ahead on MOPR

taken aback early on in Wednesday's discussion as to what constitutes a "bilateral transaction." In the commercial world, "bilateral" means direct one-to-one transactions between two parties, he said.

The issue, Greiner said, is that a generation-owning entity typically engages in multiple POLR contracts and other supply arrangements, and that anything that happens within a portfolio could be considered a bilateral transaction. He said there's nothing that doesn't come through a bilateral transaction that is fulfilling an obligation in a default service program. Theoretically, he said, just about anything could be exempt.

"It's impossible to paint the megawatts that are being used to fulfill the state retail service obligations," Greiner said. "It's just all baked in there."

Marji Philips, LS Power's vice president of wholesale market policy, said she viewed the new language as clearer than what PJM initially proposed. Philips said if stakeholders take the FERC order to its literal conclusion, then no generation owner could do any hedging in the PJM market, whether it's with public power or a load-serving entity.

Philips said what PJM could do as a work-around is having the ability to track capacity obligations for transparency.

"What PJM is proposing is a good solution to what is a financial market that FERC has told them they have some obligation to oversee," Philips said. "I think it really tries to solve a very difficult conundrum."

Sticking to the Order

But Philips and David "Scarp" Scarpignato took issue with PJM's plan to introduce in its June 1 compliance filing a new term, "re-entry capacity resource with state subsidy," for resources that return to the capacity market after failing to offer into a BRA.

MIC Chair Lisa Morelli said such resources would have a MOPR floor price of net CONE, like new-entry resources. However, PJM is proposing to treat them like existing resources regarding the penalty for accepting a subsidy after electing the competitive exemption. It would require them to forfeit capacity revenues for the delivery year but not subject them to the asset life ban applied to new resources that violate the competitive exemption.

Because FERC was "silent" on this particular issue, Morelli said, PJM decided banning such existing resources from the capacity market for their lifespan "seemed a bit harsh."

Scarp said the new definition appeared to be an attempt to "improve upon" the order.

"This is kind of pushing the envelope on whether you're complying with the order or not," he said. "I'm worried you're going to unintentionally cause a delay in getting a final order out of FERC. You're risking FERC coming back and ordering a third compliance filing."

Morelli said failing to address the issue would be unfair to resources that had accepted subsidies under rules in effect before the December FERC order expanding the MOPR. "We're not trying to get cute with the language, but it's a very real issue," she said.

Philips said PJM's proposal "so clearly contradicts what the order says."

"As Scarp noted, we have plenty of time to change the rules. As it is, the auction is on a very tight schedule," she continued. "I would encourage PJM to stick to the issues and not reinterpret what it thinks is right." ■

SPP News

SPP Briefs

MMU Releases Market Report, MISO Seam Study

SPP's Market Monitoring Unit last week released the final version of its 2019 State of the Market *report* and a study conducted for state regulators working on improving issues across the MISO seam.

The MMU shared a draft of the market report in April with the Board of Directors. (See "Lowest Prices Ever for Integrated Marketplace," *SPP Board/Members Committee Briefs: April 28, 2020*.)

The Monitor said SPP's energy prices were the lowest since its Integrated Marketplace went live in 2014. Day-ahead prices averaged about $22/MWh and real-time prices about $21/MWh, both down from $25/MWh in 2018.

The report also lists several new market-improvement recommendations, including strengthening price formation during emergencies and scarcity events, incentivizing capacity performance, and updating and improving outage coordination methodology.

The MMU will discuss the report with stakeholders during a *May 26 webinar*.

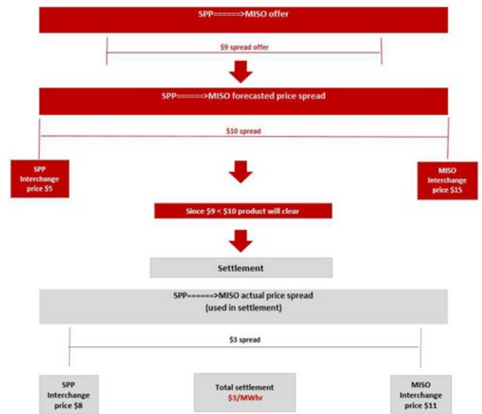
The *second report* analyzes coordinated transaction scheduling (CTS) as part of the MMU's work for the SPP Regional State Committee and the Organization of MISO States' Liaison Committee.

The study estimated that the RTOs are incurring $9.4 million to $11.2 million in economic inefficiency losses because they lack a CTS product. The MMU looked at cost and benefit information from other markets' CTS products and estimated the potential increase in flow across the SPP and MISO seam.

The MMU said several roadblocks are hampering efficiency gains, such as transmission fees and non-energy market charges for CTS transactions, ramp-rate restriction on net scheduled interchange, and price forecasting accuracy, volatility and uncertainty.

Potomac Economics, MISO's Independent Market Monitor, has also filed a *study report* with the regulatory committee that evaluates the market-to-market (M2M) coordination processes. The M2M process allows the RTOs to manage together congestion on transmission constraints that affect both SPP and MISO.

The IMM study says that "even modest improvements" in the M2M process can lead to large changes in congestion costs and efficiency savings. The RTOs' congestion costs during the one-year study period exceeded $150 million.



The flow for the coordinated transaction scheduling process across the SPP-MISO seam | *Market Monitoring Unit*

WEIS Market Participants Prep for Tests

David Kelley, SPP's director of seams and market design, told participants in the RTO's nascent Western Energy Imbalance Service (WEIS) market to "buckle up" with market trials just weeks away.

"Ensure your systems are working," Kelley told members of the Western Markets Executive Committee during a webinar Friday. "You will start to get flooded with a lot of information around market trials. It's about to be a wild ride."

In July, WEIS market participants will conduct connectivity testing to ensure their systems can "talk" with SPP's. Structured and unstructured testing will be held from August through Nov. 20.

The WEIS market, with eight participants signed up, is scheduled to go live in February 2021. Kelley said the implementation project is in yellow status only while it waits on a second release of its markets software.

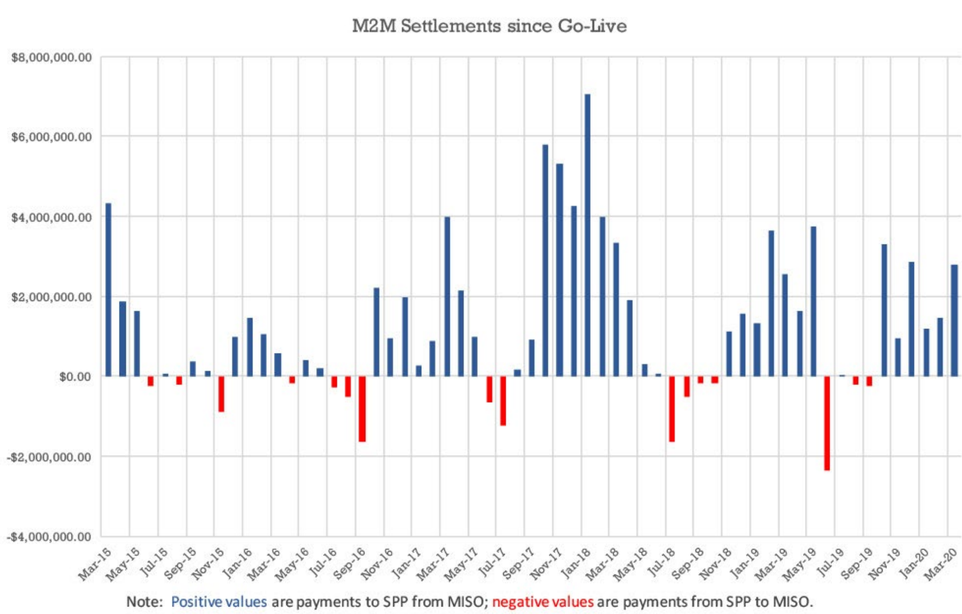
SPP, MISO Begin Year 5 of M2M Process

SPP and MISO began their fifth year of M2M operations across their seam by continuing the trend set during the first four years, with SPP again benefiting from settlements in its favor.

The RTO piled up $2.77 million in M2M settlements in March, raising its 61-month total to $76.35 million, staff told the Seams Steering Committee on Wednesday. M2M settlements have accrued to SPP for 45 months since the two RTOs began the process in March 2015.

Temporary and permanent flowgates on the RTOs' seam were binding for 681 hours during March. Temporary flowgates accounted for 429 of the binding hours. ■

— Tom Kleckner



SPP has piled up $76.35 million in market-to-market settlements from MISO since March 2015. | *SPP*

Company Briefs

Alliant Anticipates Reduction in Sales

Alliant Energy last week said the COVID-19 pandemic will likely cause a 5% decline in sales but should not affect shareholder profits the year.

The company said it expects the pandemic to result in lower commercial and industrial sales — which should be offset by an increase in residential sales — as well as pandemic-related expenses such as protective equipment for employees and unpaid bills.

Alliant announced first-quarter profits of 70 cents/share, which was up from 53 cents during the same period last year. It attributed the gains to growing ratepayer-backed investments by its Wisconsin and Iowa utilities.

More: *Wisconsin State Journal*

Clean Energy Sector Has Shed Nearly 600,000 Jobs from Pandemic

The U.S. clean energy sector has lost nearly 600,000 jobs (17% of the workforce) as COVID-19 stay-at-home orders halted production and slowed installations at homes and businesses, according to the analysis of unemployment data by the BW Research Partnership.

The sector lost 447,200 jobs in April, which was almost triple the 147,100 jobs it lost in March when states first began implementing lockdown orders to combat the spread of COVID-19. It might not get any better, as BW Research projects 500,000 more job losses sector-wide by the end of June and expects 850,000 job losses — about a quarter of all clean energy jobs — in that time.

The 594,347 jobs lost is more than double the number the sector has created since 2017, the report said.

More: *Reuters*

DTE Energy to Curb Pollution at 5 Plants as Part of Settlement

As part of a settlement agreement with DTE Energy, EPA last week said the company will reduce pollution at five coal-fired power plants in southeast Michigan, pay a $1.8 million civil penalty and pursue a $5.5 million mitigation project to improve regional air quality. The settlement is subject to a 30-day public comment period and final court approval.

EPA sued DTE in 2010 and alleged the company violated the New Source Review requirements of the Clean Air Act. The agency claimed a multimillion-dollar overhaul was made at a plant without installing the best technology available to minimize specific emissions.

In a statement, DTE said it "agreed to resolve this matter at this time and it is consistent with the company's path to drastically reduce emissions by 80% and retire its coal operations by 2040."

More: *The Detroit News*

Energy Harbor Moves to Increase Share Buybacks by $300M Amid Bailout

Energy Harbor's board of directors has voted to increase authorization for its stock buyback program from $500 million to $800 million, according to an investor presentation on the company's website. The company can buy back the stock any time until Aug. 27 under the terms of a plan approved as it spun off from FirstEnergy as it emerged from bankruptcy earlier this year.

The stock buybacks come less than a year after a multiyear lobbying effort by FirstEnergy that culminated in Gov. Mike DeWine and other lawmakers approving $1 billion in bailout money funded by surcharges on Ohioans' electric bills. The company argued that without the state money, the power plants and their parent company would become insolvent.

Energy Harbor's stock was trading at $36.01/share when markets closed on May 12, which was more than double the $15.75 price when shares first began trading on April 7.

More: *The Plain Dealer*

First Solar to Open First Southeastern Distribution Hub

Arizona-based First Solar said last week it plans to open its first Southeastern distribution hub in Greenville, S.C., near Inland Port Greer.

The company plans to open the 450,000-square-foot hub to warehouse and stage deliveries for its customers in the U.S. It will benefit from an overnight rail connection from Port Greer to the Port of Charleston, which will provide access to international markets.

More: *American Journal of Transportation*

Magnolia LNG Project Sold to Global Energy Megatrend

Global Energy Megatrend has agreed to pay $2.25 million to LNG Ltd. for its Magnolia LNG project near Lake Charles, La. The deal also includes land, detailed engineering plans and a contract for development, along with underlying LNG technology.

Magnolia LNG was expected to export 8.8 million tons of LNG each year but has yet to start construction. The project has already received permits from FERC.

More: *The Acadiana Advocate*

Majority of MidAmerican Energy's Power Came from Renewables in 2019

MidAmerican Energy last week reported that the majority (61.3%) of the power it delivered to its Iowa customers in 2019 stemmed from renewable sources, which was up 19% from 2018.

MidAmerican led the U.S. in wind project installations last year, adding more than 1 GW of new capacity, according to the American Wind Energy Association. The efforts also helped wind energy become the top source of generation in Iowa in 2019.

More: *Daily Energy Insider*

Williams' Proposed Pipeline Under Raritan Bay Denied

Williams' proposed Transco Northeast Supply Enhancement project, a proposed $1 billion natural gas pipeline that would have cut through New Jersey and under Raritan Bay, was denied key permits last week from New Jersey and New York.

New York Gov. Andrew Cuomo said the pipeline would be incompatible with a new climate law that aims to reduce greenhouse gas emissions by 85% from 1990 levels by 2050. The New York Department of Environmental Conservation also feared the pipeline would impair water quality in the Raritan Bay. A day later, the New Jersey Department of Environmental Protection followed with a denial of a wetlands permit and cited New York's rejection of the water quality permit.

More: *New Jersey Spotlight*

Federal Briefs

Chatterjee Rejects States' Request for Pipeline Approval Moratorium

FERC Chairman **Neil Chatterjee** last week rejected a request from 10 states and D.C. to pause the approvals of new infrastructure projects such as natural gas pipelines, saying energy projects are important to the country's infrastructure and a moratorium would be "short-sighted and impractical."

The attorneys generals wrote a letter saying that waiting to approve projects was necessary in order to protect the due process rights of people who might be affected by them. To that, Chatterjee said FERC continues to post all submittals and issuances on its eLibrary website and continues to receive comments, which lets the commission consider and address parties' concerns.

More: *The Hill*

Fed Makes Initial Purchases in Corporate Debt Buying Program

The Federal Reserve Bank of New York last week rolled out the first stage of its estimated $750 billion corporate bond buying program, in which it will start buying exchange-traded funds. The funds trade like stocks but have broad exposure to corporate bonds. The bank said it will then begin to buy bonds directly "in the near future."

The bank first announced it would set up the programs to restart the frozen corporate debt market on March 23. The promise immediately revived the market, allowing companies to issue debt to raise needed cash amid the economic downturn. Once they are up and running, the programs will buy both newly issued debt on the primary market and debt that is already being traded on a secondary market.

Fossil fuel companies and coal-powered utilities are set to be a part of the bond bailout. At least 90 fossil fuel companies, including ExxonMobil, Chevron and Koch Industries, stand to gain from the bond buyback program. More than 150 utilities, such as American Electric Power and Duke Energy, also stand to benefit.

More: *The New York Times*; *The Guardian*

House COVID-19 Bill Aims to Stop Utility Shutoffs

The House of Representatives on Friday voted 208-199 to pass a new, $3 trillion COVID-19 relief package, part of which aims to prevent the shutoffs of water and power in households that cannot afford to pay. The legislation would provide $3 billion ($1.5 billion each) to low-income households to pay for drinking water services and energy.

The bill also says energy or water providers that receive federal aid should not shut off customers' water or power during the pandemic because they can't pay. The drinking water assistance funding would be given to public water system owners and operators, who will then be expected to reduce rates for low-income households. The energy assistance would go through the existing Low Income Home Energy Assistance Program.

The Senate is not expected to take up the bill, which Majority Leader Mitch McConnell (R-Ky.) has dismissed as a "totally unserious effort."

More: *POLITICO*; *The Hill*

Nevada Gemini Project OK'd by Interior Department

NV Energy's $1 billion Gemini Solar Project, which would be the largest solar energy project in the U.S., was approved by U.S. Secretary of the Interior David Bernhardt last week.

The Nevada Public Utilities Commission last year approved NV Energy's integrated resource plan, which aimed to add three projects totaling up to 1,190 MW of solar energy, as well as an additional 590 MW of storage capacity. Gemini is the first to get state and federal approval.

The 690-MW solar plant will encompass 7,100 acres, making it the largest in the U.S. and the eighth-largest in the world. It will also include a 380-MW solar-powered battery system. The project will bring the company closer to complying with Senate Bill 358, which requires state energy providers to get at least half of their energy from renewable resources by 2030.

More: *Las Vegas Review-Journal*

Paringa Sues Government over Access to SBA Aid Loans During Bankruptcy

Hartshorne Mining and the Hartshorne Mining Group, subsidiaries of coal producer Paringa Resources, said last week they are suing the U.S. government after being denied $2.3 million from the federal COVID-19 relief program because the company is in the middle of a bankruptcy restructuring.

A complaint was filed against the Small Business Administration (SBA) alleging its rule barring companies in bankruptcy from accessing the Paycheck Protection Program is contrary to the statute, arbitrary and unlawfully discriminates against businesses that are in bankruptcy. Hartshorne said the companies meet every one of the statutes eligibility standards but were denied a loan because of the rule.

More: *S&P Global Market Intelligence*

Trump Admin Hits Solar, Wind Operators with Retroactive Rent Bills

The Trump administration ended a two-year rent hiatus for solar and wind projects operating on federal lands by issuing them retroactive bills when the industry is struggling with the fallout of the COVID-19 outbreak. About 96 utility-scale solar, wind and geothermal projects operate on lands run by the Interior Department's Bureau of Land Management, according to The Wilderness Society and Yale Center for Business and the Environment.

The Interior Department had stopped charging rent at the end of 2018 to review company complaints that the Obama administration had increased them too much, making them uncompetitive with rents on private property. A budget document on the department's website shows it expects to collect $50 million in rent fees for wind and solar projects in 2020.

Avangrid said it received a bill for more than $3 million for two years of rent on its 131-MW Tule wind project on federal land near San Diego. Officials at two other renewable projects also confirmed they had received retroactive rent bills.

More: *Reuters*

State Briefs

ARIZONA

Court Says Utility Regulator will be Left off Re-election Ballot

The Supreme Court last week upheld a lower court ruling that said Corporation Commissioner Boyd Dunn did not submit enough valid signatures on his nominating papers and will be removed from the re-election ballot. A campaign worker admitted in court to forging some names.

Dunn, who was first elected in 2016, came up 92 names short of qualifying for the primary after 166 names were eliminated.

More: *Capitol Media Services*

ARKANSAS

PSC Approves SWEPCO's Oklahoma Wind Purchases

The Public Service Commission last week gave its approval of Southwestern Electric Power Co.'s partial acquisition of a 1,485-MW wind project portfolio in Oklahoma. The company's investment will be $1.01 billion.

SWEPCO said it wants to acquire 810 MW (54.5%) of three power plants, collectively called the North Central Energy Facilities. Public Service Company of Oklahoma, SWEPCO's sister company, will buy the remaining 45.5% of the portfolio.

While FERC has also approved the acquisition, the utility noted that it is seeking approval from regulators in Louisiana and Texas.

More: *Renewables Now*

INDIANA

Utilities Want to Charge Customers for Lost Revenue During Pandemic

NIPSCO, Duke Energy Indiana, Indiana Michigan Power, Indianapolis Power & Light, Vectren and five other utilities last week petitioned the Utility Regulatory Commission to let them charge ratepayers for bad debt and late fees after the state temporarily banned shutoffs and late fees during the COVID-19 pandemic.

The utilities told the state they have suffered financially from lower gas and electricity use and seek to track their pandemic losses "for future recovery," letting customers pay arrearages over longer periods of time and establishing bad debt trackers to collect bad debt expense.

Consumer groups are urging Gov. Eric Holcomb to reject the "unprecedented utility greed."

More: *The Northwest Indiana Times*

KENTUCKY

PSC Approves LG&E/KU to Provide Solar Power to Toyota, Dow

The Public Service Commission last week approved a renewable power agreement (RPA) between LG&E/KU and Toyota and Dow Silicones.

As part of the RPA, Toyota will purchase 50% of the energy produced by a 100-MW solar facility in Hardin, while Dow will buy another 25%. The rest will be dispersed to customers.

More: *Daily Energy Insider*

MAINE

NECEC Gets 3rd Permit Approval; Avangrid Sues State over Referendum

Central Maine Power last week received a third key state permit, this one from the Department of Environmental Projection, needed for its proposed $1 billion New England Clean Energy Connect transmission corridor stretching from the Quebec border to Lewiston, although a challenge awaits the project at the ballot box this November.

The Land Use Planning Commission voted to grant the project a land-use certification in January, while the Public Utilities Commission approved its permit for the project in April 2019. The project still needs a U.S. Army Corps of Engineers wetlands permit, an ISO-NE section 1.3.9 approval and a Department of Energy presidential permit. It also needs municipal approval for construction projects, including substations and transmission structures along the corridor's path.

A day later, CMP parent company Avangrid Networks filed a lawsuit in Cumberland County against Secretary of State Matthew Dunlap, saying the proposed referendum violates the state constitution.

More: *Bangor Daily News*; *Bangor Daily News*

Utility Critics Plot Public Takeover of Grid

In response to the state recording longer and more frequent power outages than any other, a bipartisan bill, HP 1181, was proposed last week and suggests a newly created Power Delivery Authority that would buy the transmission and distribution infrastructure of Central Maine Power and Emera and operate it. Power plants and other generation sources would not change hands.

The bill's author, Rep. Seth Berry, and supporters say the benefits of a "consumer-owned utility" are clear: Residents would save money and it would create thousands of green jobs while improving one of the most unreliable grids. It would also give the state control over utility infrastructure, which is essential to decarbonizing and meeting climate goals. Berry estimated it would cost between $10 billion and $15 billion to fully modernize the grid.

The proposal was in committee and had yet to be voted on in March when the state's Legislature adjourned indefinitely.

More: *Energy News Network*

MONTANA

PSC Sues Media Outlets that Asked for Public Information

The Public Service Commission last week said it filed a lawsuit on April 30 against the *Billings Gazette* and others who have asked for public records about the commission's recent email spying scandal.

The Gazette's inclusion stems from a Feb. 13 public records request about PSC Commissioner Randy Pinocci and employee Drew Zinecker obtaining the emails of Commissioner Roger Koopman, who said he had no idea the eavesdropping was going on. The emails were turned over to another website, where the host read them aloud and put them on display. PSC attorney Justin Kraske asked the Lewis and Clark County District Court to determine what information the commission is obligated to turn over and cited employees' privacy concerns.

These strategic lawsuits against public participation (SLAPP suits) have become common in states that don't prevent governments from filing lawsuits when confronted with public information requests. State law provides residents the right to examine and obtain a copy of any public information, though it is balanced with an individual's right to privacy.

More: *Billings Gazette*

WYOMING

Solar Project Gets Approval from Natrona County Planning Commission

The Natrona County Planning Commission last week approved a permit for Dinosolar to build a 240-MW, utility-scale solar farm near the town of Bar Nunn. If constructed, it would be the largest in the state.

Dinosolar, a subsidiary of Enyo Renewable Energy, plans to construct the commercial PV system on 1,170 acres of leased private land, according to the permit application. However, the project still needs a conditional-use permit, granted by the county, along with other regulatory requirements, before it can proceed. Pending county and state approval, the owners hope to begin construction in September 2022 and bring it into operation by the end of 2023.

The company said the project will generate

$2.04 million in property taxes for the county in the first year of operation and $46.7 million over its 35-year lifespan.

More: *Casper Star-Tribune*